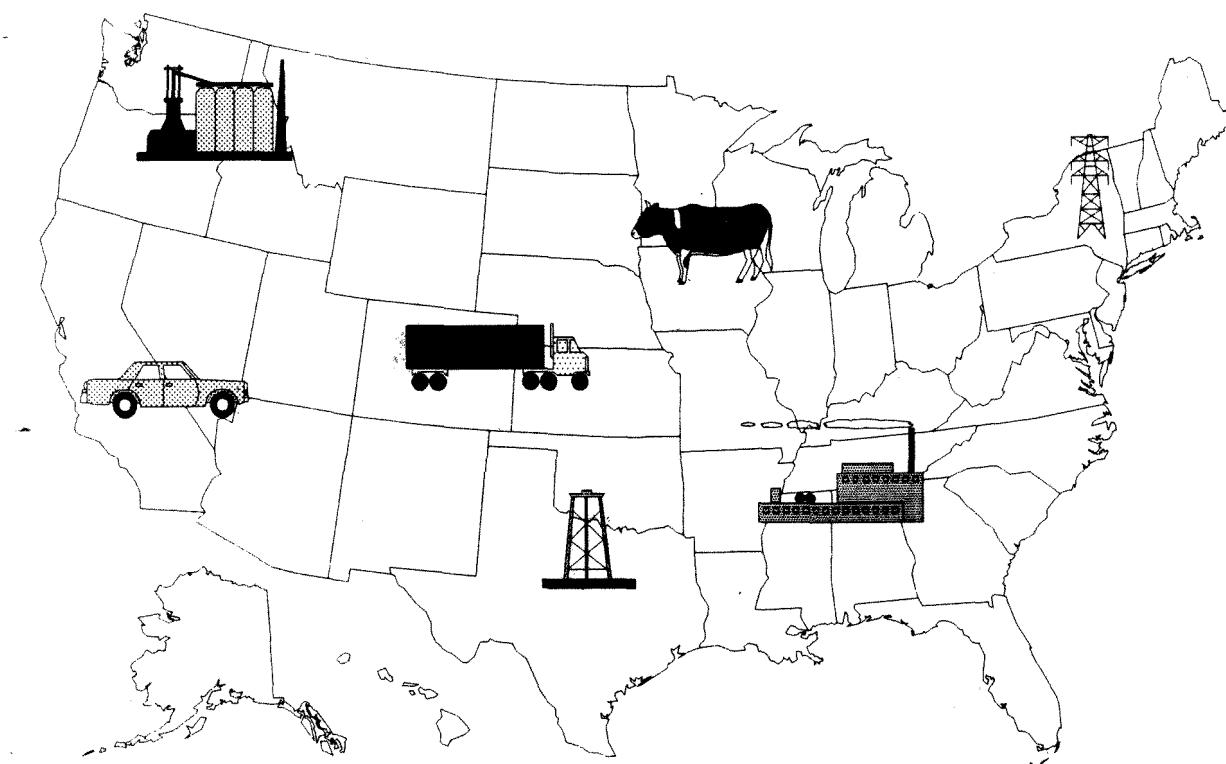


EPA

State Workbook

Methodologies For Estimating Greenhouse Gas Emissions

Second Edition



STATE WORKBOOK

METHODOLOGIES FOR ESTIMATING GREENHOUSE GAS EMISSIONS

Second Edition

**U.S. Environmental Protection Agency
Office of Policy, Planning and Evaluation
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Washington, DC 20460**

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INTRODUCTION

A. THE PURPOSE OF THE WORKBOOK

This workbook is intended to provide states with a set of methodologies to estimate their emissions of greenhouse gases and guidelines for reporting these emission estimates. Compiling an emissions inventory is a critical first step toward developing policies and strategies to mitigate greenhouse gas emissions and to assess the various options available for responding to the effects of climate change. This workbook offers both simple and more sophisticated approaches to conducting an emissions inventory, depending on the resources available and the level of effort a state can undertake.

B. GREENHOUSE GASES AND CLIMATE CHANGE

The climate of the Earth is affected by changes in radiative forcing attributable to several sources including the concentrations of radiatively active (greenhouse) gases, solar radiation, aerosols, and albedo.¹ Greenhouse gases in the atmosphere are virtually transparent to sunlight (shortwave radiation), allowing it to pass through the air and to heat the Earth's surface. The Earth's surface absorbs the sunlight and emits thermal radiation (longwave radiation) back to the atmosphere. Because some gases, such as carbon dioxide (CO₂), are not transparent to the outgoing thermal radiation, some of the radiation is absorbed, and heats the atmosphere. In turn, the atmosphere emits thermal radiation both outward into space and downward to the Earth, further warming the surface. This process enables the Earth to maintain enough warmth to support life: without this natural "greenhouse effect," the Earth would be approximately 55° F colder than it is today. However, increasing concentrations of these greenhouse gases are projected to result in increased average temperatures, with the potential to warm the planet to a level that could disrupt the activities of today's natural systems and human societies.

Naturally occurring greenhouse gases include water vapor, carbon dioxide (CO₂), methane (CH₄), nitrous oxide (N₂O), and ozone (O₃).² Some human-made compounds, including chlorofluorocarbons (CFCs) and partially halogenated fluorocarbons (HCFCs), their substitutes hydrofluorocarbons (HFCs), and other compounds such as perfluorinated carbons (PFCs), are also

¹ Albedo is the fraction of light or radiation that is reflected by a surface or a body. For example, polar ice and cloud cover increase the Earth's albedo. "Radiative forcing" refers to changes in the radiative balance of the Earth, *i.e.*, a change in the existing balance between incoming and outgoing radiation. This balance can be upset by natural causes, *e.g.*, volcanic eruptions, as well as by anthropogenic activities, *e.g.*, greenhouse gas emissions.

² Ozone exists in the stratosphere and troposphere. In the stratosphere (about 12.4 - 31 miles above the Earth's surface), ozone provides a protective layer shielding the Earth from ultraviolet radiation and subsequent harmful health effects on humans and the environment. In the troposphere (from the Earth's surface to about 6.2 miles above), ozone is a chemical oxidant and major component of photochemical smog. Most ozone is found in the stratosphere, with some transport occurring to the troposphere (through the tropopause, *i.e.*, the transition zone separating the stratosphere and the troposphere) (IPCC, 1992).

greenhouse gases. In addition, there are photochemically important gases such as carbon monoxide (CO), oxides of nitrogen (NO_x), and nonmethane volatile organic compounds (NMVOCs) that, although not greenhouse gases, contribute indirectly to the greenhouse effect. These are commonly referred to as tropospheric ozone precursors because they influence the rate at which ozone and other gases are created and destroyed in the atmosphere. Box I-1 contains a brief description of these gases, their sources, and their roles in the atmosphere.³

Although CO_2 , CH_4 , and N_2O occur naturally in the atmosphere, their recent atmospheric buildup appears to be largely the result of anthropogenic activities. This buildup has altered the composition of the earth's atmosphere, and possibly will affect future global climate. Since 1800, atmospheric concentrations of carbon dioxide have increased about 25 percent, methane concentrations have more than doubled, and nitrous oxide concentrations have risen approximately 8 percent (IPCC, 1992). And, from the 1950s until the mid-1980s, when international concern over CFCs grew, the use of these gases increased nearly 10 percent per year. The consumption of CFCs is declining quickly, however, as these gases are phased out under the *Montreal Protocol on Substances that Deplete the Ozone Layer*.⁴ Use of CFC substitutes, in contrast, is expected to grow significantly.

Despite these increases, it is impossible at this juncture to predict with certainty, the timing, magnitude, or regional distribution of any climatic change. Uncertainties about the climatic roles of oceans and clouds as well as the climate feedbacks from oceans, clouds, vegetation, and other factors make it difficult to predict the exact amount of warming that a given level of greenhouse gases, such as doubled CO_2 concentration, would cause and the rate at which any climate change would occur. If the predicted levels of climate change occur (an average global temperature change between 1.5 and 4.5°F by 2050 (IPCC, 1992)), however, the areas most vulnerable to this disruption include: forests, fisheries, coastal zones, agriculture, water resources, energy demand and supply, air quality, and human health. Potential impacts on these sectors include: loss of tree species and reduced land area of healthy forests, resulting from drier soils or increased pestilence and disease; reduced shellfish populations resulting from the loss of coastal wetlands; northward regional shifts in agricultural productivity; increased annual demand for electricity for summer cooling thereby increasing the need for total generating capacity; water use conflicts as water availability declines and demand for water, such as for irrigation and power plant cooling, increases; and increased air pollution, as air quality is directly effected by weather variables such as higher temperatures which speed the reaction rates among chemicals in the atmosphere, causing higher ozone pollution and urban smog (Smith and Tirpak, 1989).

³ For convenience, all gases discussed in this document are generically referred to as "greenhouse gases," although the reader should keep in mind the distinction between actual greenhouse gases and photochemically important trace gases.

⁴ Recognizing the harmful effects of chlorofluorocarbons and other halogenated fluorocarbons on the atmosphere, many governments signed the *Montreal Protocol on Substances that Deplete the Ozone Layer* in 1987 to limit the production and consumption of a number of these compounds. As of June 1994, 133 countries had signed the *Montreal Protocol*. The United States furthered its commitment to phase out these substances by signing and ratifying the *Copenhagen Amendments* to the *Montreal Protocol* in 1992. Under these amendments, the United States committed to eliminating the production of all halons by January 1, 1994, and of all CFCs by January 1, 1996.

Box I-1. Greenhouse Gases and Photochemically Important Gases

The Greenhouse Gases

Carbon Dioxide (CO_2). The combustion of liquid, solid, and gaseous fossil fuels is the major anthropogenic source of carbon dioxide emissions. Some other non-energy production processes (e.g., cement production) also emit notable quantities of carbon dioxide. CO_2 emissions are also a product of forest clearing and biomass burning. Atmospheric concentrations of carbon dioxide have been increasing at a rate of approximately 0.5 percent per year (IPCC, 1992), although recent measurements suggest that this rate of growth may be moderating (Kerr, 1994).

In nature, carbon dioxide is cycled between various atmospheric, oceanic, land biotic, and marine biotic reservoirs. The largest fluxes occur between the atmosphere and terrestrial biota, and between the atmosphere and surface water of the oceans. While there is a small net addition of CO_2 to the atmosphere (i.e., a net source of CO_2) from equatorial regions, oceanic and terrestrial biota in the Northern Hemisphere, and to a lesser extent in the Southern Hemisphere, act as a net sink of CO_2 (i.e., remove more CO_2 from the atmosphere than they release) (IPCC, 1992).

Methane (CH_4). Methane is produced through anaerobic decomposition of organic matter in biological systems. Agricultural processes such as wetland rice cultivation, enteric fermentation in animals, and the decomposition of animal wastes emit methane, as does the decomposition of municipal solid wastes. Methane is also emitted during the production and distribution of natural gas and oil, and is released as a by-product of coal production and incomplete fuel combustion. The atmospheric concentration of methane, which has been shown to be increasing at a rate of about 0.6 percent per year (Steele et al., 1992), may be stabilizing (Kerr, 1994).

The major sink for methane is its interaction with the hydroxyl radical (OH) in the troposphere. This interaction results in the chemical destruction of the methane compound, as the hydrogen molecules in methane combine with the oxygen in OH to form water vapor (H_2O) and CH_3 . After a number of other chemical interactions, the remaining CH_3 turns into CO which itself reacts with OH to produce carbon dioxide (CO_2) and hydrogen (H).

Halogenated Fluorocarbons, HFCs, and PFCs. Halogenated fluorocarbons are human-made compounds that include: chlorofluorocarbons (CFCs), halons, methyl chloroform, carbon tetrachloride, methyl bromide, and hydrochlorofluorocarbons (HCFCs). All of these compounds not only enhance the greenhouse effect, but also contribute to stratospheric ozone depletion. Under the Montreal Protocol and the Copenhagen Amendments, which control the production and consumption of these chemicals, the U.S. phased out the production and use of all halons by January 1, 1994 and will phase out the production of CFCs, HCFCs, and other ozone-depleting substances by January 1, 1996. Perfluorinated carbons (PFCs) and hydrofluorocarbons (HFCs), a family of CFC and HCFC replacements not covered under the Montreal Protocol, are also powerful greenhouse gases.

Nitrous Oxide (N_2O). Anthropogenic sources of N_2O emissions include soil cultivation practices, especially the use of commercial and organic fertilizers, fossil fuel combustion, adipic and nitric acid production, and biomass burning.

Ozone (O_3). Ozone is both produced and destroyed in the atmosphere through natural processes. Approximately 90 percent resides in the stratosphere, where it controls the absorption of solar ultraviolet radiation; the remaining 10 percent is found in the troposphere and could play a significant greenhouse role. Though ozone is not emitted directly by human activity, anthropogenic emissions of several gases influence its concentration in the stratosphere and troposphere. For example, the emission of chlorine and bromine-containing chemicals, such as CFCs, deplete stratospheric ozone.

Increased emissions of carbon monoxide, nonmethane volatile organic compounds, and oxides of nitrogen have contributed to the increased production of tropospheric ozone (otherwise known as urban smog). Emissions of these gases, known as criteria pollutants, are regulated under the Clean Air Act of 1970 and subsequent amendments.

Photochemically Important Gases

- **Carbon Monoxide (CO).** Carbon monoxide is created when carbon-containing fuels are burned incompletely. Carbon monoxide elevates concentrations of methane and tropospheric ozone through chemical reactions with atmospheric constituents (e.g., the hydroxyl radical) that would otherwise assist in destroying methane and ozone. It eventually oxidizes to CO_2 .
- **Oxides of Nitrogen (NO_x).** Oxides of nitrogen, NO and NO_2 , are created from lightning, biomass burning (both natural and anthropogenic fires), fossil fuel combustion, and in the stratosphere from nitrous oxide. They play an important role in climate change processes due to their contribution to the formation of ozone.
- **Nonmethane Volatile Organic Compounds (NMVOCs).** Nonmethane VOCs include compounds such as propane, butane, and ethane. Volatile organic compounds participate along with nitrogen oxides in the formation of ground-level ozone and other photochemical oxidants. VOCs are emitted primarily from transportation and industrial processes, as well as forest wildfires and non-industrial consumption of organic solvents (U.S. EPA, 1990).

Source: U.S. EPA, 1994

Drastic cuts in emissions would be required to stabilize atmospheric composition. Because greenhouse gases, once emitted, remain in the atmosphere for decades to centuries, merely stabilizing emissions at current levels would allow the greenhouse effect to intensify for more than a century. For example, emissions of carbon dioxide might have to be reduced by 50 to 80 percent to hold its current concentration constant. While it is not possible to stabilize greenhouse gas concentrations immediately, implementation of measures to reduce emissions would decrease the risk of global warming, regardless of the uncertainties about the response of the climate system (Lashof and Tirpak, 1990).

C. INTERNATIONAL, NATIONAL, AND STATE ACTIONS

Scientific consensus that the threat of climate change is real has triggered a wave of response actions by governments at the international, national, and state levels. For example, since the mid-1980s, the U.S. has taken an active role in fostering international cooperation and furthering research into understanding the causes and impacts of climate change. Initially, the U.S. worked with technical experts from over 50 countries and the Organization for Economic Cooperation and Development (OECD) to develop methods for estimating emissions and uptake of greenhouse gases. This cooperative effort supported the charge of the Intergovernmental Panel on Climate Change (IPCC), a committee jointly established by the United Nations Environment Program (UNEP) and the World Meteorological Organization (WMO) in 1988 to assess scientific information related to climate change issues. These activities culminated in the compilation of a set of internationally-accepted methods for conducting national emission inventories, the *IPCC Guidelines for National Greenhouse Gas Inventories: Vols. 1-3* (IPCC, 1994).

In June of 1992, the U.S. further demonstrated its concern about climate change by joining with 154 other nations at the United Nations Conference on Environment and Development in signing the Framework Convention on Climate Change (FCCC). Later, in October of 1992, the U.S. became the first industrialized nation to ratify the Treaty, which came into force on March 21, 1994. The FCCC commits signatories to stabilizing anthropogenic greenhouse gas emissions to "levels that would prevent dangerous anthropogenic interference with the climate system." To facilitate this, Article 4-1 requires that all parties to the FCCC develop, periodically update, and make available to the Conference of the Parties, national inventories of anthropogenic emissions of all greenhouse gases not controlled by the *Montreal Protocol*, using comparable methodologies. To fulfill its obligation under the FCCC, the U.S. government published the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1993* (U.S. EPA, 1994) and the *U.S. Climate Action Report* (U.S. Government, 1994).⁵

At the national level, the Clinton Administration developed and published the *Climate Change Action Plan* (CCAP; Clinton and Gore, 1993) to assist the U.S. in meeting its obligation under the FCCC — to return greenhouse gas emissions to 1990 levels by the year 2000. The *Climate Change Action Plan* promotes the development and expansion of approximately 50 initiatives that span all sectors of the economy and focus on reducing emissions of greenhouse gases in a cost-effective

⁵ The *Climate Action Report* represents the first formal U.S. communication under the FCCC as required by Article 4.2 and 12. It is a description of the current U.S. program. It does not seek to identify additional policies or measures that might ultimately be taken as the U.S. continues to move forward in addressing climate change, nor is it a revision to the *Climate Change Action Plan*. It is intended to identify existing policies and measures, and thus assist in establishing a basis for considering future actions.

manner. These initiatives call for cooperation between government, industry, and the public, and, since they are primarily voluntary in nature, are designed for rapid implementation. Also, the Department of Energy has recently released a set of draft guidelines for entities to report voluntarily their reductions of greenhouse gas emissions and fixation of carbon, achieved through any measure. The purpose of these guidelines is (1) to provide a database of information for entities seeking to reduce their own greenhouse gas emissions; (2) to establish a formal record of emissions and emission reductions and carbon sequestration achievements; and (3) to inform the public debate in future discussions on national greenhouse gas policy.

At the state level, the U.S. EPA's Climate Change Division, State and Local Outreach Program, has been working with states to assist them in (1) identifying their greenhouse gas emission sources and estimating their overall contribution to radiative forcing, (2) assessing the areas of the state that are most vulnerable to climate change, and (3) developing state-specific greenhouse gas mitigation strategies. In November of 1992, the Climate Change Division published the original version of this document *State Workbook: Methodologies for Estimating Greenhouse Gas Emissions* (U.S. EPA, 1992). As part of the next phase of the State and Local Outreach Program, the Climate Change Division will publish the *States Guidance Document: Policy Planning to Reduce Greenhouse Gas Emissions* (forthcoming). In addition to these activities, the National Governors' Association Task Force on Global Warming has proposed more than 20 strategies, consistent with international goals, for responding to the threat of global warming (NGA, 1991). Also, the Council of State Governments' Global Climate Change Task Force has published a plan that recommends 30 ways for Northeastern states to reduce emissions of greenhouse gases (Environmental Information Networks, Inc., 1994a).

D. THE ROLE OF THE STATES

States will need to consider a variety of issues, ranging from mass transit to reforestation, and from the recycling of wastes to the reduction of energy use, in order to develop climate change policies that reduce emissions of greenhouse gases while maintaining economic growth and development. Many states have already begun to address these issues. Examples include: a California law calling for the California Energy Commission to study the potential impact of climate change on the state's energy supply/demand, economy, environment, and agricultural and water resources; a Connecticut law establishing a broad range of energy conservation measures; the adoption of higher levels of energy efficiency standards and the initiation of an energy efficiency program focused on the reduction of CO₂ emissions by the Energy Division of the Minnesota Department of Public Service; and, an Oregon law requiring the Oregon Department of Energy to develop strategies for reducing greenhouse gas emissions (Silbiger and Gongring, 1992 and Environmental Information Networks, Inc., 1994b).

There are several reasons why states can significantly affect their emissions of greenhouse gases. First, state governments hold direct regulatory authority over the sources of more than half of all CO₂ emissions: gas and electric utilities. Second, states also determine the acceptability of building specifications and land-use planning, thereby affecting emissions from the residential, commercial, and transportation sectors. Third, states also have jurisdiction over determining regulations concerning the use and recycling of paper, glass, and plastic products, the management of municipal solid wastes (and consequently methane emissions), and the promotion of energy savings from secondary manufacturing. Finally, many states currently regulate forestry practices on non-federal lands.

A wide variety of policy options are available that have the technical potential to reduce greenhouse gas emissions. Many appear to be consistent with other economic, development, environmental, and social goals. One such policy includes identifying and implementing opportunities for cost-effective energy efficiency improvements. For example, efficiency investments that pay for themselves over the life of the equipment, through reduced energy costs, suggest that the accompanying reduction in carbon dioxide emissions may be essentially a cost-free by-product of a more efficient economy.⁶ Efficiency improvements can also reduce emissions of other pollutants, improve economic competitiveness, and enhance U.S. environmental quality, energy independence, national security, and public health (NGA, 1991). Expanding the use of non-fossil energy sources, capturing and reusing methane from landfills and coal mines, and increasing afforestation and reforestation efforts are other possible policy options with multiple benefits.

Policy-makers and planners will need to design policies and strategies to deal with the uncertainties of climate change, the potentially significant impacts climate change could have on their region's natural resources, and ways to reduce emissions of greenhouse gases to help curb climate change.⁷ This requires a three-step process: (1) an assessment of the vulnerability of resources to climate change impacts; (2) an evaluation of adaptation options; and (3) an evaluation of mitigation options.

Assessing the vulnerability of a state or region to climate change impacts involves estimating a range of regional climate change scenarios on local resources. After vulnerability assessments have been completed, a state can weigh its vulnerabilities against the economic, environmental, and social costs and benefits of various response options to the possibility of such events as sea-level rise, changes in rainfall and temperature, water conservation, forest health and production, and protection of biological diversity. The efficient implementation of these policies can best be achieved through the establishment of priorities among suggested anticipatory options (EPA, 1991).

Considerable uncertainty exists, however, regarding the economic and social costs and benefits associated with preventative measures to combat the potential effects of climate change and strategies to mitigate greenhouse gas emissions. Some estimates show that the costs associated with stabilizing greenhouse gas emissions will range anywhere from 0 to 6 percent of the U.S. GNP (Manne and Richels, 1989), while a National Academy of Sciences panel has concluded that the potential exists to reduce greenhouse gas emissions in the United States by 10 to 40 percent of 1990 levels at a very low cost and possibly at a net savings (NAS, 1991). The actual costs and benefits of alternative mitigation and adaptation strategies in an individual state will, of course, depend on the particular sectoral sources of emissions, currently available technologies, and the vulnerabilities of the agricultural, forestry, energy, and other important sectors in that state.

⁶ According to the National Academy of Science report "Policy Implications of Greenhouse Warming--Mitigation Panel", NAS Press, 1991, as quoted by Richard A. Kerr, "the most cost-effective measures for reducing emissions are by increasing the energy efficiency of residential and commercial buildings and activities, vehicles, and industrial processes that use electricity." (Science, Vol 252, 21 June 1991, pg. 252.)

⁷ Adaptation options will be necessary in the future if current and planned capabilities are found to be insufficient to address the adverse impacts of climate change. Under these options falls the debate over anticipatory versus reactive measures. Reactive measures are those which are made as climate change impacts occur; anticipatory measures are made before climate change impacts are felt. Crucial to this debate is the analysis of the economic, environmental, and social costs and benefits of any suggested options (EPA, 1991).

E. GLOBAL WARMING POTENTIAL (GWP)

When discussing greenhouse gases in a policy context, especially when attempting to estimate the costs and benefits of greenhouse gas emission reduction strategies, it is useful to have some means of estimating the relative effects of each greenhouse gas on radiative forcing of the atmosphere over some future time horizon, without performing the complex and time-consuming task of calculating and integrating changes in atmospheric composition over the period. In short, the need an index is needed that translates the level of emissions of various gases into a common metric in order to compare the climate forcing effects without directly calculating the changes in atmospheric concentrations (Lashof and Tirpak, 1990). This information can then be used for calculations of the cost-effectiveness of reductions, e.g., CO₂ emissions compared to CH₄ emissions.

A number of approaches, called Global Warming Potential (GWP) indices, have been developed in recent years. These indices account for the direct effects of growing concentrations of carbon dioxide, methane, chlorofluorocarbons, nitrous oxide, hydrofluorocarbons, and perfluorinated carbons in the atmosphere on radiative forcing. They also estimate indirect effects on radiative forcing due to emissions which are not themselves greenhouse gases, but lead to chemical reactions that create or alter greenhouse gases. These emissions include carbon monoxide, nitrogen oxides, and nonmethane volatile organic compounds, all of which contribute to formation of tropospheric ozone, which is also a greenhouse gas (Lashof and Tirpak, 1990).

This workbook follows the methodology used by the IPCC (IPCC, 1992). However, there is no universally accepted methodology for combining all the relevant factors into a single global warming potential for greenhouse gas emissions. In addition to the IPCC, there are several other noteworthy attempts to define a concept of global warming potential, including Lashof and Ahuja (1990), Rodhe (1990), Derwent (1990), WRI (1990), and Nordhaus (unpublished).

The concept of the global warming potential, as developed by the IPCC, is based on a comparison of the radiative forcing effect of the concurrent emission into the atmosphere of an equal quantity of CO₂ and another greenhouse gas. Each gas has a different instantaneous radiative forcing effect. In addition, the atmospheric concentration attributable to a specific quantity of each gas declines with time. In general, other greenhouse gases have a much stronger instantaneous radiative effect than does CO₂; however, CO₂ has a longer atmospheric lifetime and a slower decay rate than most other greenhouse gases. Atmospheric concentrations of certain greenhouse gases may decline due to atmospheric chemical processes, which in turn create other greenhouse gases or contribute to their creation or longevity. There is a substantial amount of uncertainty in our understanding of many atmospheric chemical processes, including latitudinal and temporal variations, that makes it impossible to quantify how certain gases may indirectly affect climate. Due to these uncertainties over the indirect effects, they have not been included in the GWP of each gas at this time (IPCC, 1992). Only the ability of gases to directly affect radiative forcing is included here.⁸

⁸ The one exception is methane which has a direct GWP of 11. The indirect effects of methane, however, are considered comparable in magnitude to the direct effects, therefore a GWP of 22 is used in this document (IPCC, 1992). Using a GWP of 22 for methane is also consistent with the GWP used in the *Climate Change Action Plan* (Clinton and Gore, 1993), and follows the suggestion of the International Negotiating Committee's (INC) 9th Session that requests that indirect effects of greenhouse gases be included where applicable. The magnitude of the indirect effects of other gases are either zero or uncertain, and, therefore, are not recommended for use at this time.

Following this convention, the GWP is defined as the time-integrated commitment to climate forcing from the instantaneous release of 1 kilogram of a trace gas expressed relative to that from 1 kilogram of carbon dioxide. The magnitude of the GWP is, however, sensitive to the time horizon over which the analysis is conducted (*i.e.*, the time period over which the integral is calculated). For example, Box I-2 summarizes the GWPs of key greenhouse gases assuming a 100-year time horizon. The assumed integration period defines the time period over which the radiative effects of the gas are measured. These GWPs indicate, for example, that 1 kilogram of nitrous oxide emissions is estimated to have approximately 270 times the direct impact on radiative forcing as 1 kilogram of carbon dioxide for a 100-year time horizon.

If a 500-year time horizon is assumed, however, nitrous oxide is estimated to have only 170 times the direct impact on radiative forcing compared to an equivalent amount of carbon dioxide. The differences between the values for 100 years and 500 years incorporate the differences in atmospheric lifetime.

For the discussion included in this document, the GWPs presented in Box I-2 for a 100-year time horizon are used to convert all greenhouse gases to a CO₂-equivalent basis so that the relative magnitudes of different quantities of different greenhouse gases can be readily compared. There is nothing particularly unique about this time horizon. Nevertheless, it is sufficiently long that many of the atmospheric processes currently thought to affect concentrations can be considered without excessively weighing longer-term impacts on atmospheric processes that are not well understood.

Using the GWPs presented in Box I-2, the relative contribution of each greenhouse gas to global warming for any greenhouse gas emission estimates can be calculated. For example, in Figure I-1, U.S. contributions to global warming by the primary greenhouse gases are represented using U.S.

Box I-2
Global Warming Potentials for Various Greenhouse Gases
(Direct Effects Only)

Trace Gas	GWP (100-years)	Sign of Indirect Effect
Carbon Dioxide	1	none
Methane ^a	11/22	positive
Nitrous Oxide	270	uncertain
CFC-11 ^b	-	uncertain
CFC-12 ^b	-	uncertain
CFC-113 ^b	-	uncertain
CFC-114 ^b	-	uncertain
HCFC-22 ^b	-	uncertain
HFC-134a	1,200	positive
HFC-23	10,000	positive
HFC-152a	150	positive
PFCs	5,400	positive
CO	-	positive
NO _x	-	uncertain
NMVOCs	-	positive

^a The direct GWP of methane is 11, however, the indirect effects of methane are considered comparable in magnitude to the direct effects, therefore, a GWP of 22 is recommended for use in this document.

^b Although CFCs and related compounds have very large direct GWPs, their indirect effects are believed to be negative and, therefore, could significantly reduce the magnitude of their direct effects (IPCC, 1992). Given the uncertainties surrounding the net effect of these gases, no GWP has been provided at this time.

Source: IPCC 1992.

emission estimates for the year 1990 based on conversion to a CO₂-equivalent basis using 100-year GWPs.

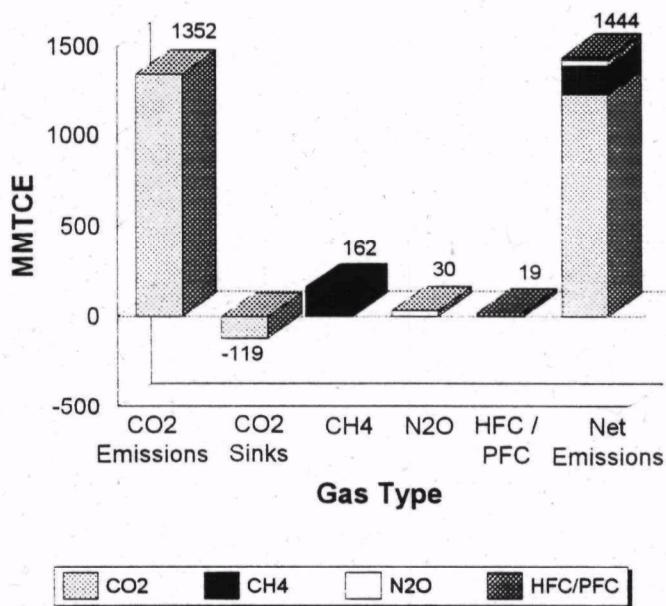
The GWP potential will be an important concept for states in determining the relative importance of each of the major emissions sources and in developing appropriate mitigation strategies.

F. THE INVENTORY PROCESS

Before a state can effectively develop policies to reduce greenhouse gas emissions and respond to climate change, it needs to identify its anthropogenic emissions sources and estimate the contribution of these emission sources to overall radiative forcing. The methodologies presented in this workbook to assist states in identifying and estimating their emissions of greenhouse gases have been adapted from Volumes 1-3 of the *IPCC Guidelines for National Greenhouse Gas Inventories* (IPCC, 1994)⁹ and the *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1993* (U.S. EPA, 1994). In many cases, the methodologies presented are consistent with the *IPCC Guidelines*, however, for emission sources considered to be major sources in the U.S., the IPCC default methodologies have been expanded and more comprehensive, U.S.-specific methods are provided.

These instances include, energy consumption, forest sinks, and some methane sources. It is suggested, however, that if a state has access to state- or region-specific emissions factors or has the ability to take on-site emission measurements at various sources, then the state should pursue these options.

Figure I-1
U.S. Greenhouse Gas Emissions and Sinks: 1990



Source: U.S. EPA, 1994

Note: MMTCE stands for million metric tonnes of carbon-equivalent.

⁹ Discussions of inventory methods can also be found in *Estimation of Greenhouse Gas Emissions and Sinks: Final Report from the OECD Experts Meeting, 18-21 February 1991* (August 1991). That report documents baseline inventory methodologies for a variety of source categories, which have subsequently been further refined based on recommendations provided at an IPCC-sponsored experts workshop held in Geneva, Switzerland in December 1991 and at an OECD/Netherlands-sponsored workshop in Amersfoort, Netherlands in February 1993. The proceedings from these meetings, the *Final Report* (OECD 1991), as well as several other international meetings, form the basis for the current *IPCC Guidelines*.

While these methods provide a solid foundation for the development of a more detailed and comprehensive emission inventory, they have several strengths and weaknesses. First of all, there are uncertainties associated with some of the emission coefficients presented. Some of the current emission coefficients, such as those for CO₂ emissions from energy-related activities and cement processing, are considered accurate. For other categories of emissions, however, a lack of data or an incomplete understanding of how emissions are generated limit the scope or accuracy of the emission coefficients. For certain categories, emission coefficients are given as a specified range to reflect the associated uncertainty. Where applicable, specific factors affecting the accuracy of these estimates are discussed in detail.

Secondly, while the methodologies provided in the *IPCC Guidelines* and the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* represent baseline methodologies for a variety of source categories, many of these methodologies are still being refined. Specific areas requiring further research include:

- Understanding the relationship between emissions and sources. This is a crucial step in completing and refining existing methodologies and in developing methodologies for emission source categories where none currently exist. For example, a great deal of uncertainty exists in how nitrous oxide emissions are produced from energy-related activities and fertilizer consumption. As a consequence, the quality of emission factors and activity data for these categories are particularly weak. In addition, methods for estimating emissions from some land-use activities and industrial processes are not included in this workbook because the scientific understanding surrounding these source categories is uncertain.
- Improving the accuracy of emissions factors. A substantial amount of research is underway that could improve the accuracy of emission factors used to calculate estimates for a variety of sources. For example, the accuracy of current emission factors used to estimate emissions from rice production is limited by a lack of available data. Emission factors for methane from landfills are also currently undergoing revision. To more accurately assess methane emissions from landfills, researchers are working to determine the relationship between moisture, climate, and waste composition and methane generation rates. Emission factors used to estimate greenhouse gas emissions from biomass burning and land use are also being revised.
- Providing appropriate activity data. Although methodologies exist for estimating emissions for some source categories, problems arise in obtaining data that are compatible with methodology requirements. For example, the ability to estimate emissions from oil and gas systems is constrained by a lack of information on compressor type, amount of leakage, and emission control technology. In the agricultural sector, estimating emissions from enteric fermentation of domesticated livestock, using the more sophisticated approach as recommended in the *IPCC Guidelines*, is arduous because of the complexity of the data required. Obtaining information on animal weights, work habits, and feeding practices by animal type is difficult. Efforts need to be made to collect activity data appropriate for use in these more sophisticated methodologies.

The uncertainties and limitations associated with calculating greenhouse gas emissions are both qualitative and quantitative. The methods provided reflect current best scientific understanding.

Efforts need to be made to improve existing methodologies and data collection activities, so that methodologies and data are consistent with one another and so that they allow states to estimate emissions with greater ease, certainty, and consistency.

Regardless of the methodologies or estimation techniques a state may decide to use, the key to a sound emissions inventory is documentation of the activity data and emission factors being used. This includes information on their derivation and clear definitions of activities. Any emissions inventory that is not accompanied by sound documentation is unverifiable. Without clear documentation on the methods employed and data used, it will be impossible to refine and improve the accuracy of greenhouse gas inventories. States may also at some point want to compare their inventories with other states, or pool statistics in a regional inventory. This can only be done if emissions are estimated using comparable and consistent methods, with data that are understandable and verifiable.

The remainder of this report is divided into two main sections: *I. Workbook Calculations* and *II. Discussion of Emission Sources and Sinks*. The Workbook Section contains simplified instructions for completing a state inventory of greenhouse gas emissions. The Discussion Section contains background information on each source and more detailed information on the recommended methods for estimating emissions as well as a description of alternate methods. The *Directions*, beginning on page xiv, provide specific instructions for completing the workbook in the most efficient manner.

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DIRECTIONS

The objectives of this report are: (1) to provide states with methodologies for estimating greenhouse gas emissions from the major anthropogenic sources; and (2) to provide analysts with important background information these source categories. In order to best achieve these two objectives, the report is divided into two sections:

- (1) **Workbook, and**
- (2) **Discussion.**

The workbook section presents step-by-step instructions for estimating emissions from each source category. For each workbook section, there is a companion discussion chapter that contains background information on emissions sources and more detailed information on the methods presented in the workbook. For example, Workbook Section 1 presents the steps for calculating CO₂ emissions from fossil fuel combustion, while Discussion Section 1 of the discussion section offers more detailed information on CO₂ emissions from energy combustion.

Analysts should first read through the background information in the discussion section. The background should provide a sufficient informational foundation to allow analysts to begin working on the calculations as presented in the workbook. Each workbook chapter contains simplified instructions for estimating emissions from a particular source. The methods presented in the workbook sections are intended to be straightforward and to require a limited amount of time to complete. Once the calculations have been completed for each source category, emissions estimates should be recorded in the Summary Table provided on page xvi.

The discussion chapters provide more detailed information on the methodology used to develop the methods presented in the workbook chapters. Therefore, analysts seeking a more thorough understanding of the methods should consult the corresponding discussion chapter. Additionally, some discussion chapters provide alternative methods for estimating emissions. These alternate methods typically are more time consuming to complete and require more detailed emissions data than those presented in the workbook section. However, in some instances they may also result in more precise estimates. States that have access to detailed data are encouraged to estimate emissions following the alternate methodologies.

WORKBOOK SECTIONS

The Workbook contains 12 sections, each pertaining to a particular anthropogenic activity that results in emissions of greenhouse gases. This section is organized as follows:

Section 1:	Carbon Dioxide Emissions from Fossil and Biomass Fuel Combustion
Section 2:	Greenhouse Gas Emissions from Production Processes
Section 3:	Methane Emissions from Oil and Natural Gas Systems
Section 4:	Methane Emissions from Coal Mining
Section 5:	Methane Emissions from Landfills
Section 6:	Methane Emissions from Domesticated Animals
Section 7:	Methane Emissions from Manure Management
Section 8:	Methane Emissions from Rice Cultivation
Section 9:	Nitrous Oxide Emissions from Fertilizer Use

- Section 10:** Greenhouse Gas Emissions from Land-Use Activities
Section 11: Greenhouse Gas Emissions from the Burning of Agricultural Crop Wastes
Section 12: Methane Emissions from Wastewater Treatment

It is recommended that states complete all 12 chapters.¹ While all chapters are important, states should spend the greatest amount of time on Chapter 1, since CO₂ emissions from fossil fuel combustion are likely to be the single greatest source of greenhouse gas emissions. After this chapter, states should work on Chapters 2 through 9, because these chapters address the next largest sources of greenhouse gas emissions.

Each workbook section includes suggested sources for the data that are required to complete the emissions calculations. In some cases, default values are provided in the event that state information is not available. However, in all cases, state information should be used where possible.

DISCUSSION SECTIONS

As mentioned previously, each Workbook Section has a corresponding Discussion Section. The purpose of the discussion chapter is to provide more complete background information on the emissions sources and to describe the method for calculating emissions in greater detail. Additionally, the discussion chapters provide information on alternate methods for calculating emissions, where appropriate. Finally, the discussion chapters indicate the potential limitations of the methods presented and provide additional reference information.

Discussion Sections 13 and 14 (Greenhouse Gas Emissions from Mobile Sources and Greenhouse Gas Emissions from Stationary Sources, respectively) do not have corresponding workbook chapters because the calculations required to estimate these emissions are very time consuming, data intensive, and complex. Moreover, states may already be estimating these emissions (at least CO, NO_x, and NMVOCs) as a result of ongoing efforts to monitor their compliance with the *Clean Air Act*. Accordingly, it is not recommended that states estimate emissions from these sources. However, it is recommended that the analyst read through the background information in the discussion chapters.

OTHER INFORMATION

In addition to the Workbook and Discussion Sections, included in this document are the following:

- **Glossary:** Includes definitions of terms related to climate change and a list of chemical symbols and conversion factors.
- **Contacts:** Includes a list comprised of state environmental and energy offices that could aid analysts in their work on climate change.
- **Bibliography:** Includes a list of key reports on climate change impacts, adaptation measures, and emissions mitigation activities that could be useful to a state developing mitigation and adaptation strategies.

¹ Most states, however, will not need to complete Chapters 4 and 8, because coal is mined only in thirteen states and rice is produced in only seven.

SUMMARY TABLE FOR REPORTING EMISSIONS ESTIMATES

SOURCE	GAS	EMISSIONS (tons, on a full molecular basis)	GWP	EMISSIONS (CO ₂ -Equivalent)
Fossil Fuel Combustion	CO ₂		1	
Biomass Fuel Combustion	CO ₂		1	
Production Processes	CO ₂		1	
	N ₂ O		270	
	PFCs		5,400	
	HFC-23		10,000	
Natural Gas and Oil Systems	CH ₄		22	
Coal Mining	CH ₄		22	
Landfills	CH ₄		22	
Domesticated Animals	CH ₄		22	
Manure Management	CH ₄		22	
Rice Cultivation	CH ₄		22	
Fertilizer Use	N ₂ O		270	
Forest Management & Land-Use Change	CO ₂		1	
Burning of Agricultural Crop Wastes	CH ₄		22	
	N ₂ O		270	
	NO _x		—	
	CO		—	
Wastewater Treatment	CH ₄		22	
Total Emissions (All sources, excluding biomass fuels)	CO ₂		1	
	CH ₄		22	
	N ₂ O		270	
	NO _x		—	
	CO		—	
	PFCs		5,400	
	HFC-23		10,000	

PART I

WORKBOOK SECTIONS

WORKBOOK 1

CARBON DIOXIDE EMISSIONS FROM COMBUSTION OF FOSSIL AND BIOMASS FUELS

Carbon dioxide is emitted during the combustion of fossil and biomass fuels. Fossil fuels include coal, oil, and natural gas. For this calculation, biomass fuels primarily include wood, charcoal, bagasse, agricultural wastes, and vegetal fuels.

To estimate state emissions of carbon dioxide from fossil and biomass fuels, seven steps should be performed: 1) obtain the required energy data; 2) estimate the total carbon content of the fuels; 3) estimate the total carbon stored in products; 4) estimate the carbon potentially emitted from bunker fuel consumption; 5) estimate the carbon emitted from interstate electricity consumption; 6) calculate net potential carbon emissions; 7) estimate the carbon actually oxidized from energy uses; and, 8) convert net carbon emissions from energy consumption to total CO₂ emissions. These seven steps are outlined in detail below. A worksheet has been provided in Table 1-1 to assist in the calculations. A more detailed description of the method used to calculate carbon dioxide emissions is provided in Discussion Section 1.

Step (1) Obtain Required Energy Data (Table 1-1, Column A)

- *Required Energy Data.* The information needed to perform these calculations is annual state energy consumption data based on fuel type (e.g., gasoline, residual oil, bituminous coal, lignite, natural gas, etc.) by sector (i.e., residential, commercial, industrial, transportation, and electric utility). A list of suggested sector/fuel categories is provided in Table 1-1. Additionally, further disaggregation may be done (i.e., by individual industries within the industrial sector or by specific fuel types not listed) if the appropriate data are available.
- *Data Sources.* In-state sources, such as state energy commissions or public utility commissions, should be consulted first. Alternatively, state energy data by fuel type and sector for fossil fuels can be found in the U.S. Department of Energy (U.S. DOE), Energy Information Administration's (EIA) *State Energy Data Report* and *Coal Production*. For users attempting to disaggregate the data further (e.g., by specific end user, such as chemical manufacturers), there is currently no nationally published source providing this type of information. An appropriate source would need to be obtained at the state level to obtain these data.
- *Units for Reporting Data.* Fossil fuel statistics should also be provided on an energy basis (i.e., million Btu). Wood data should be reported in pounds, while ethanol should be reported on an energy basis. If fuel data are reported in other units and documented conversion factors cannot be obtained within the state, the conversion factors listed in Table 1-2 may be applied in order to convert to million Btu.

Example	According to the EIA <i>State Energy Data Report 1992</i> , total U.S. energy consumption of distillate fuel for the transportation sector in 1990 was 658 million barrels, which is equivalent to approximately 3.83×10^{15} Btu, or 3,832,850,000 million Btu as shown in the following calculation:
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$$658,000,000 \text{ barrels} \times 5.825 \text{ million Btu/barrel} = 3,832,850,000 \text{ million Btu}$$

Table 1-1. Worksheet to Calculate CO₂ Emissions from Fossil & Biomass Fuels

Sector/Fuel	Input (A)	Input (B)	$(A) \times (B) \div 2000$	Input (C)	Input (D)	$(C) \div (D) \div (E)$	$(F) \times$ <i>Fraction Oxidized</i>	$(G) \times 44/12$
	Consumption (10 ⁶ Btu)	Carbon Content Coefficient (lbs C/10 ⁶ Btu)	Total Carbon (tons C)	Stored Carbon (tons C)	International Bunkers (tons C)	Net Carbon (tons C)	Total C Oxidized (tons C)	CO ₂ Emissions (tons CO ₂)
RESIDENTIAL								
Asphalt and Road Oil								
Aviation Gasoline								
Distillate Fuel Oil								
Jet Fuel: Kerosene Type								
Jet Fuel: Naphtha Type								
Kerosene								
LPG								
Lubricants								
Misc. Petroleum Products								
Motor Gasoline								
Naphtha (<104°F)								
Other Oil (>104°F)								
Pentane Plus								
Petroleum Coke								
Residual Fuel Oil								
Still Gas								
Waxes								
Anthracite Coal								
Bituminous Coal								
Sub-bituminous Coal								
Lignite Coal								
Coke								
Natural Gas								
Wood								
Ethanol								
Residential Total								

Table 1-1. Worksheet to Calculate CO₂ Emissions from Fossil & Biomass Fuels

Table 1-1. Worksheet to Calculate CO₂ Emissions from Fossil & Biomass Fuels

Sector/Fuel	Input (A) Consumption (10 ⁶ Btu)	Input (B) Carbon Content Coefficient (lbs C/10 ⁶ Btu)	(A) x (B) ÷ 2000 (C)	Input (D) Stored Carbon (tons C)	Input (E) International Bunkers (tons C)	(C) - (D) - (E) (F)	(F) x Fraction Oxidized (G)	(G) x 44/12 (H)
	Total Carbon (tons C)	Stored Carbon (tons C)	Net Carbon (tons C)	Total C Oxidized (tons C)	CO ₂ Emissions (tons CO ₂)			
INDUSTRIAL								
Asphalt and Road Oil								
Aviation Gasoline								
Distillate Fuel Oil								
Jet Fuel: Kerosene Type								
Jet Fuel: Naphtha Type								
Kerosene								
LPG								
Lubricants								
Misc. Petroleum Products								
Motor Gasoline								
Naphtha (<104°F)								
Other Oil (>104°F)								
Pentane Plus								
Petroleum Coke								
Residual Fuel Oil								
Still Gas								
Waxes								
Anthracite Coal								
Bituminous Coal								
Sub-bituminous Coal								
Lignite Coal								
Coke								
Natural Gas								
Wood								
Ethanol								
Industrial Total								

Table 1-1. Worksheet to Calculate CO₂ Emissions from Fossil & Biomass Fuels

Table 1-1. Worksheet to Calculate Emissions from Fossil & Biomass Fuels

Sector/Fuel	Input (A) Consumption (10 ⁶ Btu)	Input (B) Carbon Content Coefficient (lbs C/10 ⁶ Btu)	(A) x (B) ÷ 2000 (C) Total Carbon (tons C)	Input (D) Stored Carbon (tons C)	Input (E) International Bunkers (tons C)	(C) - (D) - (E) (F) Net Carbon (tons C)	(F) x Fraction Oxidized (G) Total C Oxidized (tons C)	(H) CO ₂ Emissions (tons CO ₂) (G) x 44/12
ELECTRIC UTILITIES								
Asphalt and Road Oil								
Aviation Gasoline								
Distillate Fuel Oil								
Jet Fuel: Kerosene Type								
Jet Fuel: Naphtha Type								
Kerosene								
LPG								
Lubricants								
Misc. Petroleum Products								
Motor Gasoline								
Naphtha (<104°F)								
Other Oil (>104°F)								
Pentane Plus								
Petroleum Coke								
Residual Fuel Oil								
Still Gas								
Waxes								
Anthracite Coal								
Bituminous Coal								
Sub-bituminous Coal								
Lignite Coal								
Coke								
Natural Gas								
Wood								
Ethanol								
Utilities Total								

Table 1-2. Conversion Factors to Million Btu.^a

Fuel Type	If data is in	Multiply by
<i>Petroleum</i>		
Asphalt and Road Oil	barrels	6.636
Aviation Gasoline	barrels	5.048
Distillate Fuel Oil	barrels	5.825
Jet Fuel: Kerosene Type	barrels	5.670
Jet Fuel: Naphtha Type	barrels	5.355
Kerosene	barrels	5.670
Liquified Petroleum Gases	barrels	4.011
Lubricants	barrels	6.065
Miscellaneous Petroleum Products and Crude Oil	barrels	5.800
Motor Gasoline	barrels	5.253
Naphtha (<104°F) ^b and Special Naphthas	barrels	5.248
Other Oil (>104°F) ^b and Unfinished Oils	barrels	5.825
Pentane Plus	barrels	4.620
Petroleum Coke	barrels	6.024
Residual Fuel Oil	barrels	6.287
Still Gas ^b	barrels	6.000
Waxes	barrels	5.537
<i>Coal^c</i>		
Anthracite ^e	short tons	21.668
Bituminous	short tons	23.89
Sub-bituminous	short tons	17.14
Lignite	short tons	12.866
Coal Coke	short tons	24.800
<i>Natural Gas</i>		1.03 x 10 ⁶
	Teracalories	3968
<i>Biofuels</i>		
Wood ^d	Btu	0.116x10 ³ (lbs/Btu)
Ethanol	gallons	0.764
<i>Interstate Electricity Consumption^f</i>		10,000 (Btu/kWh)
a. Heat contents of many fuels vary somewhat by source, year, and consumer. Except for coal, biomass, and blended petroleum products, this variation tends to be relatively small. The values here are national averages for 1990.		
b. By EIA definition naphtha (<104°F), other oil (>104°F), and still gas are collectively termed petrochemical feedstocks.		
c. Thermal conversion factors for coal can vary extensively by source. More complete state and sector specific factors are available through U.S. DOE/EIA.		
d. The energy content of wood varies with moisture content and type of wood. The conversion factor given is a nationally averaged value based on dry mass of hardwood. Since wood consumption figures should be in pounds, the factor should be used to convert consumption from Btu to pounds.		
e. The anthracite factor presented here is a national average. Actual anthracite factors could range from as low as 17.5 MMBtu/ton for anthracite reclaimed from refuse piles to 26 MMBtu/ton or higher for anthracite mined directly from the original seam.		
f. This is a national average heat rate based on EIA data (EIA, 1994e) and should only be used for interstate electricity consumption for which the specific heat rate of the source is unknown.		
Source: Petroleum, natural gas, and wood heat-equivalents are from EIA's <i>Annual Energy Review 1993</i> . Coal heat-equivalents are from EIA's <i>State Energy Data Report 1992</i> , <i>Cost and Quality of Fuels for Electric Utility Plants</i> , and <i>Quarterly Coal Report</i> . Ethanol heat-equivalents are from EIA's <i>Estimates of U.S. Biomass Consumption 1992</i> .		

Step (2) Estimate Total Carbon Content in Fuels (Table 1-1, Columns B and C)

- Carbon content represents the total amount of carbon that could be emitted if 100 percent was released to the atmosphere. To estimate the total carbon that could be released from the fuels, multiply energy consumption for each fuel type by the appropriate carbon content coefficient. This calculation should be done for all fuel types in each sector. To estimate carbon content of wood, the carbon coefficient is replaced by the fraction of carbon in biomass. Table 1-3 presents default carbon content coefficients, including a national carbon content coefficient for ethanol as well as a default value for the percent of carbon in wood. State-specific data should be used in place of these values when they are available and well documented. Multiplying fuel consumption by these coefficients yields potential emissions in pounds of carbon. The equations will take the following form:

$$TC_i = C_i \times CCC_i$$

where: TC_i = Total carbon contained in fuel i (lbs C);

C_i = Fuel consumption for fuel i (10^6 Btu); and

CCC_i = Carbon content coefficient for fuel i (lbs C/ 10^6 Btu).

- For each fuel type, divide the results by 2000 lbs/ton to obtain tons of carbon.
- For each sector, sum the results of the fuel types to obtain the total carbon content in tons. The figures for carbon from biomass consumption *should not* be included in total emissions (see Discussion Section 1 for an explanation).

Example To calculate the total carbon content for distillate fuel in the U.S. transportation sector for the year 1990, obtain the result from Step 1 (3,832,850,000 million Btu of distillate fuel) and perform the following calculations:

(a) 3,832,850,000 million Btu \times 44.0 lbs C/ 10^6 Btu = 168,645,400,000 lbs C

(b) 168,645,400,000 lbs C \div 2000 lbs/ton = 84,322,700 tons C

Step (3): Estimate Carbon Stored in Products (Table 1-1, Column D)

- Estimate the quantity of each fuel type that is consumed in non-fuel uses. In-state sources, such as state energy commissions or public utility commissions, should be consulted first. Otherwise, rough national estimates can be found in U.S. DOE/EIA *Annual Energy Review* and the assumption can be made that the fraction of a fuel used in non-fuel uses at the state level is roughly equivalent to the fraction used at the national level.
- Calculate the carbon content of fuels consumed in non-fuel uses by multiplying the non-fuel use quantities by their respective carbon coefficients in Table 1-3.
- Estimate the fraction of carbon in each fuel which is stored for a long period of time (*i.e.*, 20 years or more). National default values are given in Table 1-4, but state level fractions may differ depending on the type of non-fuel uses present. The values in Table 1-4 should be used only as

a last resort and with careful consideration given to their defining assumptions (see Discussion Section 1). State-specific estimates should be used whenever possible and presented with adequate supporting documentation.

- Calculate the carbon stored by multiplying the carbon content of non-fuel uses by the fraction sequestered.
- Enter the resulting values in Column D of Table 1-1. These values are eventually subtracted from total carbon potentially emitted (Table 1-1, Column C).

Example

To calculate carbon stored by non-fuel use of LPG at the national level in 1990, obtain the quantity consumed from Table 1.15 of *Annual Energy Review 1993* and perform the following calculations:

- (a) 1,280,000,000 million Btu \times 37.8 lbs C/10⁶ Btu = 48,384,000,000 lbs C
- (b) 48,384,000,000 lbs C \div 2000 lbs/ton = 24,192,000 tons C
- (c) 24,192,000 tons C \times 0.80 = **19,353,600 tons C stored**

Step (4): Estimate Carbon from Bunker Fuel Consumption (Table 1-1, Column E)

- International bunker fuels and domestic bunker fuels are fuels used in international and interstate transportation respectively (see Discussion Section 1 for a more detailed description of these categories). Emissions from domestic bunkers are not addressed in state emission inventories due to difficulties in obtaining the necessary data. Emissions from international bunkers are calculated, but should not be included in a state's total emissions figures. This omission of bunker fuel consumed internationally is consistent with international greenhouse gas reporting guidelines developed by the IPCC (1994).
- International bunker fuel emissions are calculated in the same manner as other emissions from fossil fuel combustion. Once consumption of international bunker fuels are determined, they are multiplied by their appropriate carbon content coefficients (see Table D1-3). This results in the amount of carbon potentially emitted by combustion of these fuels, or total carbon contained in the fuels, as shown in the equation below:

$$TC_i = C_i \times CCC_i$$

where: TC_i = Total Carbon contained in bunker fuel i (pounds);

C_i = Consumption of bunker fuel i (million Btu); and

CCC_i = Carbon Content Coefficient for bunker fuel i (lbs C / million Btu)

- The total carbon contained in each bunker fuel should be entered in Column E of Table 1-1. These values should be subtracted from total carbon (Column C of Table 1-1) *only* if international bunkers have been captured in the total carbon figures. If the carbon values in Column C do not include international bunker fuels, then the values in Column E should not be deducted.

Example

At the national level, distillate fuel oil used for international bunkers is obtained from U.S. DOE/EIA *International Energy Annual*. The 1990 figure for the U.S. and its territories is 19,345,000 barrels. The following calculations are performed to compute carbon in distillate fuel used for international bunkers:

- (a) 19,345,000 barrels X 5.825 million Btu/barrel = 112,685,000 million Btu
- (b) 112,685,000 million Btu X 44.0 lbs C/million Btu = 4,958,140,000 lbs C
- (c) 4,958,140,000 lbs C + 2000 lbs/ton = **2,479,070 tons C**

Step (5): Estimate Carbon Emitted from Interstate Electricity Consumption (Reported Separately)

- Electricity derived from fossil fuels is often consumed across state boundaries (*i.e.*, fuel can be consumed in one state to generate electricity which is consumed in another state). To obtain a complete accounting of emissions from fossil fuel consumption, emissions from this interstate flux of energy should be estimated. The first step in calculating these emissions is to estimate the quantity of electricity imported to and exported from a state (*i.e.*, the amount of fuel consumed in-state to produce energy which is used out of state and vice versa). Energy consumption data should be reported in million Btu (see Table 1-2 for conversion from physical units and kilowatthours).
- Determine the source of interstate electricity (*e.g.*, electricity generated at coal fired plants, natural gas plants, etc.). Source identification is necessary in order to derive accurate heat rates and proper carbon content coefficients for interstate electricity consumption.
- After interstate electricity sources have been identified and data obtained in the appropriate units, then the carbon content of the energy can be determined. Carbon contents are directly related to the type of fuel associated with each energy source. Once the fuel type for each source has been identified, the carbon content coefficients in Table 1-3 can be applied to fuel quantities in order to estimate the carbon content of interstate energy consumption.
- The following equation summarizes the steps outlined above:

$$EI_i = Imp_i \times HR_i \times CCC_i$$

$$EE_j = Exp_j \times HR_j \times CCC_j$$

where: EI = Emissions of carbon due to imports from source i (lbs carbon);

EE = Emissions of carbon due to exports from source j (lbs carbon);

Imp = Electricity imported from source i (kwh);

Exp = Electricity exported from source j (kwh);

HR = Heat Rates of generating facilities (Btu/kwh); and

CCC = Carbon Content Coefficients for source fuels (lbs carbon /Btu).

Table 1-3: Carbon Content Coefficients for Fuel Combustion^a
 (lbs C/ 10^6 Btu)

Fuel Consumed	Carbon Coefficient
Asphalt and Road Oil	45.5
Aviation Gas	41.6
Distillate Fuel Oil	44.0
Jet Fuel (all kinds)	43.5
Kerosene	43.5
LPG	37.8
Lubricants	44.6
Motor Gasoline	42.8
Residual Fuel Oil	47.4
Misc. Petroleum Products and Crude Oil	44.7
Naphtha (<104°F)	40.0
Other Oil (>104°F)	44.0
Pentanes Plus	40.2
Petrochemical Feed	42.7
Petroleum Coke	61.4
Still Gas	38.6
Special Naphtha	43.8
Unfinished Oils	44.6
Waxes	43.7
Anthracite Coal	62.1
Bituminous Coal	56.0
Sub-bituminous Coal	57.9
Lignite Coal	58.7
Natural Gas	31.9
Wood ^b	0.475
Ethanol	41.8

Except as noted all coefficients are given as pounds of carbon emitted per million Btu of fuel consumed (lbs C/ 10^6 Btu). When multiplied by consumption in 10^6 Btu, or pounds for wood, they result in emissions of carbon in pounds (lbs C).

a. Content coefficients are sometimes called carbon content coefficients or carbon coefficients.

b. The wood coefficient is a percent of total carbon in biomass (%C).

Sources: Natural gas and petroleum coefficients are from U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1993*. Coal coefficients are full combustion figures based on EIA's *Emissions of Greenhouse Gases in the United States: 1985-1990*. The wood carbon fraction is from the *IPCC Guidelines for National Greenhouse Gas Inventories*. The ethanol coefficient is from OTA's *Changing by Degrees*.

Table 1-4: Percent of Carbon Sequestered by Non-fuel Uses^a

Fuel Type	Fraction Stored
Coal Oils and Tars from coke production	0.75
Natural Gas as a chemical feedstock	1.00
Asphalt and Road Oil	1.00
LPG	0.80
Lubricants	0.50
Petrochemical Feedstocks ^b	0.80
Waxes and Miscellaneous Products ^c	1.00

a. Before using these fractions, see Discussion 1 for assumptions on which they are based.
 b. By EIA definition, "Petrochemical Feedstocks" include naphtha (<104°F), other oil (<104°F), and still gas.
 c. By EIA definition, "Waxes and Miscellaneous Products" includes waxes, Misc. petroleum products, residual fuel oil and distillate fuel oil.
Sources: Figures for coal oil and tars, asphalt and road oil, LPG, and lubricants are from Marland and Rotty (1984). The Figure for natural gas is from communication with EIA (Rypinski, 1994). Petrochemical feedstocks and waxes and miscellaneous products are from U.S. EPA (1994).

- Emissions from interstate electricity consumption are then summed over all fuel types, and exported electricity emissions are subtracted from imported electricity emissions.

$$NE = \sum EI_i - \sum EE_j$$

where: NE = Net Emissions from interstate electricity consumption (lbs carbon);
 EI = Emissions of carbon due to imports from source i (lbs carbon); and
 EE = Emissions of carbon due to exports from source j (lbs carbon);

- Report the resulting values separately from other emissions from fossil fuel consumption for energy. These values *should not* be used to adjust state emission totals. A negative number for net emissions indicates a net export of carbon from interstate electricity, while a positive number indicates a net import of carbon from interstate electricity. If these emissions were distributed across end-use consumers, a net import would result in an increase in state emission totals, because it represents additional consumption attributable to end-users within the state. A net export would result in a decrease in state totals, because it represents fuel consumed in a state to produce energy used by out-of-state consumers.

Step (6): Calculate Net Potential Carbon Emissions (Table 1-1, Column F)

- Subtract the carbon stored (Table 1-1, Column D) and, if necessary, the carbon emitted from bunker fuel consumption (Table 1-1, Column E) from the total carbon (Table 1-1, Column C).
- The resulting value is "net carbon content" and should be entered in Column F of Table 1-1.

Example At the national level the carbon content of LPG consumed in the U.S. is approximately 30,400,000 tons carbon, the amount sequestered in non-fuel uses is about 19,400,000 tons carbon, and there is no consumption of LPG for international bunkers. To calculate the net carbon content of LPG combusted in the industrial sector perform the following calculation:

$$(a) 30,400,000 \text{ ton C} - 19,400,000 \text{ ton C stored} - 0 \text{ ton C bunkers} = 11,000,000 \text{ ton C}$$

Step (7): Estimate Carbon Oxidized from Energy Uses (Table 1-1, Column G)

- Multiply the net carbon content for each fuel and sector by the fraction of carbon oxidized to obtain the total amount of carbon oxidized to carbon dioxide from the combustion of the fuel. The fraction of carbon oxidized is 0.99 for solid and liquid fuels, 0.995 for natural gas, and 0.90 for wood. This calculation will take the following form:

$$\text{Net Carbon Content (tons)} \times \text{Fraction Oxidized} = \text{Total Oxidized Carbon (tons C)}$$

- Sum the results to obtain the total amount of carbon oxidized from all fuel types. The figures for carbon from biomass consumption *should not* be included in total emissions (see Discussion Section 1 for an explanation).

Example To calculate the total amount of Carbon Oxidized from the combustion of LPG in the U.S. industrial sector perform the following calculation, where the net carbon content of industrial LPG is about 11,000,000 ton C:

$$(a) 11,000,000 \text{ tons C} \times 0.99 = 10,890,000 \text{ tons C}$$

Step (8): Convert to Total CO₂ Emissions from Energy Consumption (Table 1-1, Column H)

- Multiply Total Carbon Oxidized for each fuel and sector by the molecular weight ratio of CO₂ to C (44/12) to obtain Total CO₂ Emissions.
- Sum across each fuel and each sector to find total state emissions of CO₂ from energy consumption. The figures for carbon from biomass consumption *should not* be included in total emissions (see Discussion Section 1 for an explanation).

Example To convert the amount of carbon emitted due to LPG consumption (10,890,000 tons C) to the amount of CO₂ emitted, perform the following calculation.

$$(a) 10,890,000 \text{ tons C} \times 44 / 12 = 39,930,000 \text{ tons CO}_2$$

WORKBOOK 2

GREENHOUSE GAS EMISSIONS FROM PRODUCTION PROCESSES

Emissions are often produced as a by-product of various non-energy related activities. That is, these emissions are produced directly from the process itself and are not a result of energy consumed during the process. For example, in the industrial sector raw materials are chemically transformed from one state to another. This transformation often results in the release of greenhouse gases such as carbon dioxide, nitrous oxide, hydrofluorocarbons, and perfluorinated carbons. The production processes addressed in this section include: cement production, nitric acid production, adipic acid production, lime production, limestone use (*e.g.*, for iron and steel making, flue gas desulfurization, and glass manufacturing), soda ash production and use, carbon dioxide manufacture, aluminum production, and HCFC-22 production.

Greenhouse gases are emitted from a number of industrial processes not covered in this section. For example, ammonia production is believed to be an industrial source of methane, nitrous oxide, and NMVOC emissions. However, emissions for these sources have not been estimated at this time due to a lack of information on the emission processes, the manufacturing data, or both. As more information becomes available, emission estimates for these processes will be calculated and included in future greenhouse gas emission inventories.

The emission methodologies presented here generally follow the IPCC-recommended guidelines, although the only processes for which the IPCC provides a specific methodology for estimating emissions are cement, adipic acid, and nitric acid production. The IPCC has not provided specific details (*e.g.*, default emission factors) to calculate emissions from the other sources, but recommends a basic approach that can be followed for each source category, *i.e.*, multiplying production data for each process by an emission factor per unit of production. The methods provided to estimate emissions in this section generally follow this basic approach. Most of the emission factors provided below were taken from U.S. EPA (1994), in which they were derived using calculations that assume precise, efficient chemical reactions. As a result, uncertainties in the emission coefficients can be attributed to impurities contained in the raw materials or to inefficiencies in the chemical reactions associated with each production process. Additional sources of uncertainty specific to an individual source category are discussed in *Part II* of this document.

2.1 CO₂ FROM CEMENT PRODUCTION

Step (1) Obtain Required Data

- *Required Data.* The information needed to calculate CO₂ emissions from cement production is annual clinker production and annual masonry cement production in short tons in the state.
- *Data Source.* In-state sources should be consulted first. Additionally, cement production by state can be found in the *Cement: Annual Report*, published by the U.S. Bureau of Mines.
- *Units for Reporting Data.* Annual production of clinker and portland and masonry cement

should be supplied in short tons.

Example According to the Bureau of Mines *Cement Annual Report: 1990* (Bureau of Mines 1992a), total U.S. clinker production in 1990 was **70,939,000 short tons**, and total masonry cement production was **3,208,000 short tons**.

Step (2) Estimate CO₂ Emissions from Clinker Production

- Multiply clinker production by an emissions factor of 0.507 tons CO₂/ ton of clinker produced to yield total CO₂ emissions from clinker production.

$$\text{Total CO}_2 \text{ Emissions (tons)} = \text{Total Clinker Production (tons)} \times 0.507 \text{ (tons CO}_2/\text{ton of clinker produced)}$$

Example To calculate Total CO₂ Emissions from U.S. clinker production in 1990:

$$70,939,000 \text{ tons} \times 0.507 \text{ tons CO}_2/\text{ton cement} = \mathbf{35,966,073 \text{ tons CO}_2}$$

Step (3) Estimate CO₂ Emissions from Masonry Cement

- Multiply masonry cement production by an emissions factor of 0.0224 tons of CO₂/ ton of masonry cement produced

$$\text{Total CO}_2 \text{ Emissions (tons)} = \text{Total Masonry Cement Production (tons)} \times 0.0224 \text{ (tons CO}_2/\text{ton of masonry cement produced)}$$

Example To calculate Total CO₂ Emissions from masonry cement production in 1990:

$$3,208,000 \text{ tons} \times 0.0224 \text{ tons CO}_2/\text{ton masonry cement} = \mathbf{71,859 \text{ tons CO}_2}$$

Step (4) Sum the Results of Steps (1) and (2)

Total CO₂ emissions from cement production are the sum of the results obtained through Steps (1) and (2).

Example To calculate Total CO₂ Emissions from cement production in 1990,

$$35,966,073 \text{ tons CO}_2 \text{ (clinker)} + 71,859 \text{ tons CO}_2 \text{ (masonry cement)} = \mathbf{36,037,932 \text{ tons CO}_2}$$

2.2 N₂O FROM NITRIC ACID PRODUCTION

Step (1) Obtain Required Data

- *Required Data.* The only information needed to calculate N₂O emissions from nitric acid production is annual nitric acid production in short tons in the state.
- *Data Source.* In-state sources should be consulted first. Additionally, nitric acid production can be found in *Chemical and Engineering News* (C&EN; published by the American Chemical Society, Washington, D.C.).
- *Units for Reporting Data.* Annual production of nitric acid should be supplied in short tons.

Example According to C&EN (1994), total U.S. nitric acid production in 1990 was approximately **8 million short tons**.

Step (2) Estimate N₂O Emissions from Nitric Acid Production

- Multiply nitric acid production by an emissions factor of 0.0055 tons N₂O/ton of nitric acid produced to yield total N₂O emissions from nitric acid production.

$$\text{Total N}_2\text{O Emissions (tons)} = \text{Total Nitric Acid Production (tons)} \times 0.0055 \text{ (tons N}_2\text{O/ton of nitric acid produced)}$$

Example To calculate Total N₂O Emissions from U.S. nitric acid production in 1990,
8 million tons \times 0.0055 tons CO₂/lbs nitric acid = **44,000 tons N₂O**

2.3 N₂O FROM ADIPIC ACID PRODUCTION

Step (1) Obtain Required Data

- *Required Data.* The information needed to calculate N₂O emissions from adipic acid production is annual adipic acid production in short tons and the pollution control equipment used at production facilities in the state.
- *Data Source.* In-state sources should be consulted first. Additionally, adipic acid production can be found in *Chemical and Engineering News*.
- *Units for Reporting Data.* Annual production of adipic acid should be supplied in short tons.

Example According to C&EN (1993), total U.S. adipic acid production in 1990 was approximately **810,000 short tons**.

Step (2) Estimate N₂O Emissions from Adipic Acid Production

- Multiply adipic acid production by an emissions factor of 0.3 tons N₂O/ton of adipic acid produced to yield total N₂O emissions from adipic acid production. Subtract the amount of N₂O that is not released as a result of pollution control equipment.

Total N₂O Emissions (tons) = Total Adipic Acid Production (tons) x 0.3 (tons N₂O/ton of adipic acid produced) - Amount N₂O not Released as a Result of Pollution Control Equipment.

Example To calculate Total N₂O Emissions from U.S. adipic acid production in 1990,¹

$$810,000 \text{ tons} \times 0.3 \text{ tons N}_2\text{O/tons adipic acid} - 181,057 \text{ tons N}_2\text{O} = 61,943 \text{ tons N}_2\text{O}$$

¹

Due to existing levels of pollution control, 181,057 tons of N₂O were kept from being released to the atmosphere.

2.4 CO₂ FROM LIME MANUFACTURE

Step (1) Obtain Required Data

- *Required Data.* The information needed to calculate CO₂ emissions from lime manufacture is annual lime production in short tons and the amount of CO₂ recovered during manufacturing and used for other purposes in the state.
- *Data Source.* In-state sources should be consulted first. Additionally, lime production by state can be found in *Lime Annual Report* (Bureau of Mines, Washington, D.C.)
- *Units for Reporting Data.* Annual production of lime should be supplied in short tons.

Example According to the Bureau of Mines (1992b), total U.S. lime production in 1990 was approximately **17,481 thousand short tons** and **573 thousand tons of CO₂** were recovered and used in sugar refining and precipitated calcium carbonate production.

Step (2) Estimate CO₂ Emissions from Lime Manufacture

- Multiply lime production by an emissions factor of 0.785 tons CO₂/ton of lime produced to yield total CO₂ emissions from lime manufacture. If any CO₂ is recovered and used for other purposes, subtract this amount from the total.

Total CO₂ Emissions (tons) = Total Lime Production (tons) x 0.785 (tons CO₂/ton of lime produced) - Amount CO₂ Recovered (tons).

Example To calculate Total CO₂ Emissions from U.S. lime production in 1990,

$$[17,481,000 \text{ tons} \times 0.785 \text{ tons CO}_2/\text{tons lime}] - 573,000 \text{ tons CO}_2^1 = 13,150,000 \text{ tons CO}_2$$

¹ Some of the CO₂ generated during the production process, however, is recovered for use in sugar refining and precipitated calcium carbonate (PCC) production. Lime production by these producers was 911 thousand short tons, generating 716.5 thousand short tons of carbon dioxide. Approximately 80 percent of this CO₂ is recovered and not emitted.

2.5 CO₂ FROM LIMESTONE USE

Step (1) Obtain Required Data

- *Required Data.* The data required for use in this method is the amount of limestone consumed in each state by type: (1) limestone (calcite), and (2) dolomite.
- *Data Source.* In-state sources should be consulted first. Additionally, lime production by state can be found in *Crushed Stone: Annual Report* (Bureau of Mines, Washington, D.C.).
- *Units for Reporting Data.* Annual consumption of limestone and dolomite should be supplied in short tons.

Example According to the Bureau of Mines (1993b), total U.S. limestone use in 1990 was approximately **12,606,000 short tons**: 11,582,000 short tons limestone (calcite) and 1,024,000 short tons dolomite.

Step (2) Estimate CO₂ Emissions from Limestone Use

- Depending on the type of limestone used, multiply the amount of limestone consumed by the appropriate emissions factor: (1) 0.12 for limestone (calcite) and (2) 0.13 for dolomite. This will provide the amount of carbon emitted from the use of limestone. Next, this number will be multiplied by 44/12 to obtain the amount of carbon dioxide actually emitted.

a) Limestone (Calcite)

$$\begin{aligned} \text{Total CO}_2 \text{ Emissions (tons)} &= \text{Limestone Used (tons)} \times 0.12 \text{ tons C/ton Limestone (Calcite)} \\ &\times 44/12 \text{ CO}_2/\text{C.} \end{aligned}$$

b) Dolomite

$$\begin{aligned} \text{Total CO}_2 \text{ Emissions (tons)} &= \text{Limestone Used (tons)} \times 0.13 \text{ tons C/ton Dolomite} \times 44/12 \\ &\text{CO}_2/\text{C.} \end{aligned}$$

Example To calculate Total CO₂ Emissions from lime consumption in 1990,

Calcite

$$[11,582,000 \text{ tons} \times 0.12 \text{ tons C/ton limestone (calcite)}] \times 44/12 \text{ CO}_2/\text{C} \\ = 5,096,080 \text{ tons CO}_2$$

Dolomite

$$[1,024,000 \text{ tons} \times 0.13 \text{ tons C/ton limestone (dolomite)}] \times 44/12 \text{ CO}_2/\text{C} \\ = 488,100 \text{ tons CO}_2$$

Step (3) Sum the Results of Steps 2a and 2b to Obtain Total Emissions

Total CO₂ Emissions from Limestone Use = Total CO₂ from Limestone (Calcite) (tons CO₂) + Total CO₂ from Dolomite (tons CO₂).

Example To calculate Total CO₂ Emissions from limestone use in 1990,

$$5,096,080 \text{ tons CO}_2 \text{ limestone (calcite)} + 488,100 \text{ tons CO}_2 \text{ (dolomite)} = 5,584,180 \text{ tons CO}_2$$

2.6 CO₂ FROM SODA ASH MANUFACTURE AND CONSUMPTION

Step (1) Obtain Required Data

- *Required Data.* The data required for use in this method is the amount of trona (the principal ore from which natural soda ash is made) produced and the amount of finished soda ash consumed in short tons in each state.
- *Data Source.* In-state sources should be consulted first. Additionally, trona production and soda ash consumption by state can be found in *Soda Ash: Annual Report* (Bureau of Mines, Washington, D.C.) and *Current Industrial Reports* (Bureau of Census, U.S. Department of Commerce, Washington, D.C.).
- *Units for Reporting Data.* Annual production of trona and consumption of soda ash should be supplied in short tons.

Example According to the Bureau of Mines (1993c), total U.S. trona production in 1990 was approximately 16,241,200 short tons, while soda ash consumption was 7,194,700 short tons.

Step (2) Estimate CO₂ Emissions Soda Ash Manufacture

- Multiply the amount of trona produced by the emissions factor 0.0974 tons CO₂/ton trona:

Total CO₂ Emissions (tons) = Trona Produced (tons) x 0.0974 tons CO₂/ton Trona.

Example To calculate Total CO₂ Emissions from trona production in 1990,

$$16,241,200 \text{ tons} \times 0.0974 \text{ tons CO}_2/\text{ton trona} = 1,581,893 \text{ tons CO}_2$$

Step (3) Estimate CO₂ from Soda Ash Consumption

- Multiply the amount of soda ash consumed by the emissions factor 0.415 tons CO₂/ton soda ash consumed.

Total CO₂ Emissions (tons) = Soda Ash Consumed (tons) x 0.415 tons CO₂/ton Soda Ash.

Example To calculate Total CO₂ Emissions from soda ash consumption in 1990,

$$7,194,700 \text{ tons} \times 0.415 \text{ tons CO}_2/\text{ton soda ash} = 2,985,800 \text{ tons CO}_2$$

Step (4) Sum the Results of Steps 3 and 4 to Obtain Total Emissions

Total CO₂ Emissions from Soda Ash Manufacture and Use = Total CO₂ from Trona Production (tons CO₂) + Total CO₂ from Soda Ash Consumption (tons CO₂).

Example To calculate Total CO₂ Emissions from soda ash manufacture and consumption in 1990,

$$\begin{aligned} 1,581,893 \text{ tons CO}_2 (\text{manufacture}) + 2,985,800 \text{ tons CO}_2 (\text{consumption}) \\ = 4,567,693 \text{ tons CO}_2 \end{aligned}$$

2.7 CO₂ EMISSIONS FROM CARBON DIOXIDE MANUFACTURE

Step (1) Obtain Required Data

- Required Data.** The data required for use in this method is the amount of carbon dioxide produced that is not accounted for in other emission sources (e.g., combustion or non-fuel use).
- Data Source.** In-state sources should be consulted first. Additionally, carbon dioxide manufacture by state can be found in *Business Research Report B286: Carbon Dioxide* (Freedonia Group, Inc., Cleveland, Ohio).
- Units for Reporting Data.** Annual production of carbon dioxide should be supplied in short tons.

Example According to The Freedonia Group (1991), total U.S. carbon dioxide manufacture in 1990 for already unaccounted for uses (i.e., enhanced oil recovery) was approximately **1,322,760 short tons**.

Step (2) Estimate CO₂ Emissions Carbon Dioxide Manufacture

- Multiply the amount of carbon dioxide consumed by the emissions factor 1 ton CO₂/ton CO₂.

$$\text{Total CO}_2 \text{ Emissions (tons)} = \text{Carbon Dioxide Consumed (tons)} \times 1 \text{ tons CO}_2/\text{ton CO}_2 \text{ consumed.}$$

Example To calculate Total CO₂ Emissions from carbon dioxide manufactured in 1990,

$$1,322,760 \text{ tons CO}_2 \text{ manufactured} \times 1 \text{ ton CO}_2/\text{ton CO}_2 \text{ manufactured} = \mathbf{1,322,760 \text{ tons CO}_2}$$

2.8 PFC - CF₄ AND C₂F₆ — EMISSIONS FROM ALUMINUM PRODUCTION

Step (1) Obtain Required Data

- Required Data.* The data required for use in this method is the amount of aluminum produced in a state in short tons.
- Data Source.* In-state sources should be consulted first. Additionally, aluminum production by state can be found in *Aluminum, Bauxite, and Alumina: Annual Report* (Bureau of Mines, Washington, D.C.) and *Current Industrial Reports* (Bureau of Census, U.S. Department of Commerce, Washington, D.C.).
- Units for Reporting Data.* Annual production of carbon dioxide should be supplied in short tons.

Example According to the Bureau of Mines (1993a), total U.S. aluminum production in 1990 was approximately **4,462,000 short tons**.

Step (2) Estimate PFC - CF₄ and C₂F₆ — Emissions from Aluminum Production

- Multiply the amount of aluminum produced by the appropriate emissions factor: 0.0006 (range of 0.0003 to 0.0009) tons CF₄/ton aluminum produced and 0.00006 (range of 0.00003 to 0.00009) ton C₂F₆/ton aluminum produced.

$$\text{Total PFC Emissions (tons)} = [\text{Aluminum Produced (tons)} \times 0.0006 \text{ tons CF}_4/\text{ton aluminum produced}] + [\text{Aluminum Produced (tons)} \times 0.00006 \text{ tons C}_2\text{F}_6/\text{ton aluminum produced}]$$

Example To calculate Total PFC Emissions from aluminum production in 1990,

$$[4,462,000 \text{ tons} \times 0.0006 \text{ tons CF}_4/\text{ton aluminum produced}] + [4,462,000 \text{ tons} \times 0.00006 \text{ tons C}_2\text{F}_6/\text{ton aluminum produced}] = 2,945 \text{ tons CO}_2$$

2.9 EMISSIONS OF HFC-23

The only HFC known to be emitted in significant quantities as a by-product from chemical production processes is HFC-23. HFC-23 is emitted as a by-product of HCFC-22 production.

Step (1) Obtain Required Data

- *Required Data.* The data required for use in this method is the amount of HCFC-22 produced in a state.
- *Data Source.* In-state manufacturers of HCFC-22 should be consulted first. Additionally the Chemical Manufacturers Association (Washington, D.C.), Alliance for Responsible CFC Policy (Arlington, VA), and Grant Thornton Consulting (Washington, D.C.) can be contacted for information on state-by-state production numbers.
- *Units for Reporting Data.* Annual production of HCFC-22 should be supplied in short tons.

Step (2) Estimate HFC-23 Emissions from HCFC-22 Production

- Multiply the amount of HCFC-22 produced by the appropriate emissions factor: 0.04 tons HFC-23/ton HCFC-22 produced (or 4% of total HCFC-22 production).

$$\begin{aligned} \text{HCFC-22 Produced (tons)} \times 0.04 \text{ tons HFC-23/ton HCFC-22 produced} \\ = \text{Total HFC-23 Emissions (tons)} \end{aligned}$$

Example To calculate Total HFC Emissions from HCFC-22 production for a state,

$$\begin{aligned} 4,000,000 \text{ tons HCFC-22} \times 0.04 \text{ tons HFC/ton HCFC-22 produced} \\ = 160,000 \text{ tons HFC-23} \end{aligned}$$

WORKBOOK 3

METHANE EMISSIONS FROM NATURAL GAS AND OIL SYSTEMS

Emissions from natural gas and oil systems are primarily methane, although smaller quantities of non-methane VOCs, carbon dioxide, and carbon monoxide can be emitted. Methane emissions occur throughout the total fuel cycles of oil and natural gas. From the natural gas systems, methane emissions occur during field production, processing, refining, storage and injection, transmission, distribution, and from engine exhaust. From the production and refining of petroleum liquids, methane emissions occur during field production, storage, refining, marine vessel operations, and from venting and flaring of gas.

To estimate these emissions, the following steps should be taken: 1) obtain the required data on activity levels for the different segments of the fuel systems; 2) multiply activity levels by the appropriate emission factor; and 3) sum across activity types to calculate total emissions. A more detailed discussion of the suggested method for estimating CH₄ emissions from oil and natural gas systems is contained in the Discussion Section, chapter 3.

Step (1) Obtain Activity Data

- *Required Data.* The information required to estimate emissions from this source is based on activity (e.g., production) by sector (oil or gas). Data required include: the amount of oil produced, refined, transported, and stored at oil facilities; and the amount of natural gas produced, processed and distributed to consumers.
- *Data Sources:* In-state agencies should be consulted first. However, if it is difficult to obtain data from these sources, state-by-state data can be found in the *Natural Gas Annual* (published by EIA/DOE) and *Gas Facts* (published by the American Gas Association).
- *Units for Reporting Data:* Data for oil and gas should be provided in energy units of million BTU (MMBTU). Since oil data is usually reported in barrels and gas data in million cubic feet (MMcf), apply the conversion factors listed in Table 3-1 to convert to million BTU.

Example A state producing 60 million barrels would produce an energy equivalent of:

$$60,000,000 \text{ barrels} \times 5.825 \text{ million BTU/barrel} = 349,500,000 \text{ million BTU}$$

Step (2) Estimate Methane Emissions in Tons

- Multiply activity data by the appropriate emissions factor, as presented in Table 3-2. Do this for each activity type presented in Table 3-2.

$$\text{Activity Level (MMBTU)} \times \text{Emissions Factor (low, lbs CH}_4/\text{MMBTU)} = \text{lbs CH}_4 \text{ (low)}$$

Table 3-1. Conversion Factors to Million BTU (MMBTU)

Fuel Type	If Data is Reported in	Multiply by
Oil	Barrels	5.825 ^a
Gas	Million Cubic Feet (MMcf)	0.001 ^b
a Source:		Energy Information Administration (EIA), (1994), "Annual Energy Review: 1993," <u>U.S. Department of Energy</u> , Washington D.C., July 1994.
b There are 1000 BTUs in 1 cubic foot of natural gas.		

Table 3-2. Methane Emission Factors for Activities

Sector	Activity Data (MMBTU)	Emissions Factor (lbs CH ₄ /MMBTU)		
		Low	High	Median
Oil & Gas Production				
Oil	Oil Production	700	11,610	6,150
Gas	Gas Production	106,770	194,960	150,870
Oil & Gas: Venting and Flaring	Oil & Gas Produced ^a	6,960	32,490	19,730
Crude Oil Transportation and Refining				
Transportation	Oil Tankered	1,730	1,730	1,730
Refining	Oil Refined	210	3,250	1,730
Storage Tanks	Oil Refined	50	580	310
Natural Gas Processing, Transport, and Distribution				
Gas Processing, Transmission, and Distribution	Gas Consumption	132,300	273,880	203,090
a Emissions are based on total production of oil and gas.				
Source: IPCC, 1994				

Activity Level (MMBTU) x Emissions Factor (high, lbs CH₄/MMBTU) = lbs CH₄ (high)

Activity Level (MMBTU) x Emissions Factor (median, lbs CH₄/MMBTU) = lbs CH₄ (median)

- Divide the number of lbs/CH₄ obtained by 2,000 lbs/ton to obtain tons of CH₄ produced.

lbs CH₄ (low, for each activity) ÷ 2,000 lbs/ton = tons CH₄ (low, for each activity)

lbs CH₄ (high, for each activity) ÷ 2,000 lbs/ton = tons CH₄ (high, for each activity)

lbs CH₄ (median, for each activity) ÷ 2,000 lbs/ton = tons CH₄ (median, for each activity)

Example A state producing 1 million BTUs (MMBTUs) of natural gas could expect emissions from natural gas production facilities of:

Low

$$1 \text{ (MMBTU)} \times 106,770 \text{ (lbs CH}_4\text{/MMBTU)} = 106,770 \text{ lbs CH}_4$$

$$106,770 \text{ lbs CH}_4 \div 2,000 \text{ lbs/ton} = 53.4 \text{ tons CH}_4$$

High

$$1 \text{ (MMBTU)} \times 194,960 \text{ (lbs CH}_4\text{/MMBTU)} = 194,960 \text{ lbs CH}_4$$

$$194,960 \text{ lbs CH}_4 \div 2,000 \text{ lbs/ton} = 97.5 \text{ tons CH}_4$$

Median

$$1 \text{ (MMBTU)} \times 150,870 \text{ (lbs CH}_4\text{/MMBTU)} = 150,870 \text{ lbs CH}_4$$

$$150,870 \text{ lbs CH}_4 \div 2,000 \text{ (lbs/ton)} = 75.4 \text{ tons CH}_4$$

Step (3) Estimate Total Methane Emissions from Oil and Natural Gas Systems

- Sum across activity types (i) to obtain total methane emissions from oil and natural gas systems.

$$\sum_{i=1}^{i_x} \text{tons CH}_4 \text{ (low)} = \text{Total CH}_4 \text{ Emissions from Oil and Gas Systems (tons CH}_4\text{, low estimate)}$$

$$\sum_{i=1}^{i_x} \text{tons CH}_4 \text{ (high)} = \text{Total CH}_4 \text{ Emissions from Oil and Gas Systems (tons CH}_4\text{, high estimate)}$$

$$\sum_{i=1}^{i_x} \text{tons CH}_4 \text{ (median)} = \text{Total CH}_4 \text{ Emissions from Oil and Gas Systems (tons CH}_4\text{, median estimate)}$$

WORKBOOK 4

METHANE EMISSIONS FROM COAL MINING

Methane and coal are formed together during coalification, a process in which vegetation is converted by geological and biological forces into coal. Methane is released when pressure within a coalbed is reduced, either through mining or through natural erosion or faulting.

To estimate state emissions of methane from coal mining, the following steps should be performed: 1) obtain the required data -- annual coal production from surface and underground mines; 2) calculate methane emissions from underground coal mining; 3) calculate methane emissions from surface mining; 4) calculate post-mining emissions; and, 5) calculate total coal mining emissions. These steps are outlined in detail below. A more thorough description of the methodology used to estimate methane emissions from coal mines is provided in Discussion Section 4.

The Discussion Section also includes a more detailed, alternate methodology for estimating methane emissions from underground mines. This alternate approach uses mine-specific data on 1990 methane emissions from ventilation systems at gassy underground mines. States that produce large amounts of coal from gassy underground mines are encouraged to calculate underground emissions using this alternate method. These states are: Alabama, Colorado, Illinois, Kentucky, Maryland, Ohio, Pennsylvania, Utah, Virginia, and West Virginia.

Step (1) Obtain Required Data

- *Required Data.* The data required to estimate methane emissions from coal mining are annual coal production from surface mines and from underground mines.¹ For the states of West Virginia and Kentucky, coal production will need to be obtained for each county rather than total production for the state. Additionally, coal mine methane that is recovered for pipeline sales rather than emitted to the atmosphere should be obtained for the states of Alabama, Utah, and Virginia.
- *Data Source.* State energy offices should be able to provide data on annual coal production from surface and underground mines. Alternatively, the annual *Coal Production* reports produced by the Department of Energy/Energy Information Administration (DOE/EIA) contain surface and underground coal production by state and by county. Data on methane recovered for pipeline sales is typically available from state agencies that track oil and gas production.
- *Units for Reporting Data.* Coal production data should be reported in million short tons. Methane emissions data should be reported in million cubic feet (million cf).

Step (2) Calculate Methane Emissions from Underground Mines

- The first step in calculating methane emissions from underground mines is to find the annual underground coal production for the state. State underground coal production should be recorded in the first row of column 1 in Table 4-1, which is located on the last page of this section. For West Virginia, coal production for counties in northern West Virginia and from

¹ It is important to distinguish between underground production and surface production because shallow, surface mined coals tend to hold less methane than deeper, underground mined coals.

counties in southern West Virginia will need to be recorded separately. Also, for Kentucky, coal production for eastern Kentucky and for western Kentucky will need to be recorded separately. This is necessary because mines in different regions of these two states are part of different coal basins and the methane emissions factors for these basins differ. Following is a list of counties that are in northern West Virginia and the counties that are in eastern Kentucky:

Northern West Virginia Counties: Barbour, Braxton, Brooke, Gilmer, Grant, Harrison, Lewis, Marion, Marshall, Mineral, Monongalia, Ohio, Pendleton, Preston, Randolph, Taylor, Tucker, Upshur, Webster. All other coal producing counties are southern West Virginia.

Western Kentucky Counties: Butler, Caldwell, Crittenden, Christian, Daviess, Edmonston, Grayson, Hancock, Henderson, Hopkins, Logan, McLean, Muhlenberg, Ohio, Todd, Union, Webster. All other coal producing counties are in eastern Kentucky.

- Next, record the appropriate methane emissions coefficient (methane emitted per ton of coal mined) in column 2 of Table 4-1. Emissions coefficients are shown below for six different regions in the U.S. Both a low and high emissions coefficient are given so that the potential range of emissions may be calculated.

Methane Emissions Coefficient for Coal Produced from Underground Mines			
Basin	Emissions Coefficient (cf CH ₄ /ton coal mined)		High
	Low	High	
Central Appalachian Basin: Eastern Kentucky, Tennessee, Virginia, southern West Virginia	215	325	
Northern Appalachian Basin: Maryland, Ohio, Pennsylvania, northern West Virginia	425	740	
Black Warrior Basin (Alabama Only)	2000	3000	
Rockies and Southwest Basins: Colorado, New Mexico, Utah	370	470	
Illinois Basin: Illinois, Indiana, western Kentucky	160	190	
All Other States:	50	150	

Example According to DOE/EIA's *Coal Production 1992*, coal production from underground mines in Illinois was 46,965,000 short tons in 1992. Using the emissions coefficients in the table above, estimated methane emissions from underground mines in Illinois are:

Low: 46,965 million tons \times 160 cf/ton = 7,514 million cf.
 High: 46,965 million tons \times 190 cf/ton = 8,923 million cf.

Step (3) Calculate Methane Emissions from Surface Mines

- Coal production from surface mines should be recorded in the second row of column 1 in Table 4-1. Surface coal mining primarily occurs in the western U.S. and the eastern states of Illinois, Indiana, western Kentucky, Pennsylvania and Virginia.
- For surface mined coal, the low emissions coefficients are assumed to be from 1 to 3 times the in-situ methane content of the coal. The surface mining emissions coefficients for the major coal basins are shown below. Record the appropriate low and high state surface mining emissions coefficients in row 2 of column 2 in table 4-1.

Methane Emissions Coefficient for Coal Produced from Surface Mines		
Basin	Emissions Coefficient (cubic feet methane/ton of coal mined)	
	Low	High
Central Appalachian Basin: Eastern Kentucky, Tennessee, Virginia, southern West Virginia	50	150
Northern Appalachian Basin: Maryland, Ohio, Pennsylvania, northern West Virginia	50	150
Black Warrior Basin: Alabama	50	150
Rockies and Southwest Basins: Colorado, New Mexico, Utah	15	45
Illinois Basin: Illinois, Indiana, western Kentucky	40	120
All Other States:	3	10

- Calculate methane emissions from surface mines by multiplying the low and high methane emissions coefficients by surface coal production. Record the resulting estimated emissions in row 2 of column 3 in table 4-1.

Example According to DOE/EIA's *Coal Production 1992*, coal production from surface mines in Illinois was approximately 12,892,000 short tons. Using the given low and high emissions coefficients, estimated methane emissions from surface mines in Illinois are:

$$\begin{aligned} \text{Low: } & 12,892 \text{ million tons} \times 40 \text{ cf/ton} = 516 \text{ million cf.} \\ \text{High: } & 12,892 \text{ million tons} \times 120 \text{ cf/ton} = 1,547 \text{ million cf.} \end{aligned}$$

Step (4) Calculate Post-Mining Methane Emissions

- Some methane remains in the coal after it has been mined and can be emitted during

transportation and handling of the coal. Post-mining emissions should be calculated for both surface and underground mined coals. First, record coal production in column 1 of table 4-1. Record underground coal production in row 3 and surface coal production in row 4 (rows 3 and 4 will be identical to rows 1 and 2 for column 1).

- Next, surface and underground coal production should be multiplied by the appropriate emissions coefficient to estimate post-mining methane emissions. Post-mining emissions coefficients are determined by assuming that from 25 percent to 40 percent of the in-situ methane content of the coal escapes during post-mining activities. Post-mining emissions coefficients for underground and surface-mined coal are shown below. The appropriate state emissions coefficients should be recorded in column 2 of table 4-1.
- Once the appropriate emissions coefficients have been recorded, multiply surface and underground coal production by the emissions coefficients to calculate post-mining emissions. Emissions should be recorded in column 3 of table 4-1.

Post-Mining Methane Emissions Coefficients Surface and Underground Mines				
	Underground Mines (cf/ton)		Surface Mines (cf/ton)	
	Low	High	Low	High
Central Appalachian Basin: Eastern Kentucky, Tennessee, Virginia, southern West Virginia	80	130	12	20
Northern Appalachian Basin: Maryland, Ohio, Pennsylvania, northern West Virginia	40	70	12	20
Black Warrior Basin: Alabama	80	130	12	20
Rockies and Southwest Basins: Colorado, New Mexico, Utah	55	90	4	6
Illinois Basin: Illinois, Indiana, western Kentucky	14	22	10	16
All Other States:	10	16	0.8	1.3

Example Using the surface and underground coal production shown in the examples above, post-mining methane emissions for Illinois are calculated as follows:

Surface: Low = 12.892 million tons x 10 cf/ton = 129 million cf
High = 12.892 million tons x 16 cf/ton = 206 million cf

Underground: Low = 46.965 million tons x 14 cf/ton = 658 million cf
High = 46.965 million tons x 22 cf/ton = 1,033 million cf

Step (5) Calculate Total Methane Emissions from Coal Mining

- To find the low and high total emissions from coal mining, add together emissions from underground mines and surface mines and post-mining emissions. Record the low and high total emissions from coal mining in row 5 of column 3 in Table 4-1. The low and high total emissions represent the potential range of state coal mine methane emissions.
- Next, calculate the average of the low and high total emissions estimates and record that value in row 6 of Table 4-1. This value may be used as a single approximation of state coal mining methane emissions. It is important to note, however, that there is a large degree of uncertainty associated with using a single emissions estimate; the range developed from the low and high values represent the best approximation of state emissions.
- Next, the amount of coal mine methane that is recovered for energy purposes, rather than emitted to the atmosphere, must be subtracted from the total emissions estimates. Currently, recovery projects are in operation at mines in the states of Alabama, Utah, and Virginia. The coal companies that have developed projects are shown below, along with the estimated methane that was recovered and sold to pipelines in 1992. More recent data on methane recovered for pipeline sales is typically available from state agencies that track state oil and gas production. It is important to note that only coal mine methane that is recovered in association with active coal mining operations should be included. Production from "stand-alone" coalbed methane projects (*i.e.*, projects that are similar to conventional oil and gas production but that recover natural gas from coal seams) should not be included. The states of Alabama, Colorado, and New Mexico are large producers of natural gas from stand-alone coalbed methane wells.

Current Coal Mine Methane Pipeline Projects			
Mining Company	Number of Mines	State	1992 Methane Recovered (million cf)
Jim Walter Resources	4	Alabama	12,268
U.S. Steel Mining	1	Alabama	2,260 (est.)
CONSOL Coal Group ¹	4	Virginia	4,000
Soldier Creek Coal	1	Utah	5,000

¹ 1992 was the first year of production for these mines. Methane recovered for pipeline sales has increased substantially since that time.

- For those states that have current coal mine methane recovery projects, record the quantity of methane that is recovered for pipeline sales in row 7 of Table 4-1. The amount recovered should be recorded in million cf. Subtract the amount recovered from the total average emissions to obtain total methane emitted to the atmosphere. Record this value in row 8 of Table 4-1.
- Finally, total methane emissions should be converted from million cubic feet to tons by multiplying by 20.66 tons per million cf. This value should be recorded in row 9 of table 4-1.

Example

Total coal mine methane emissions for Illinois are calculated as follows:

(million cf)	<u>Low</u>	<u>High</u>
Underground:	7,514	8,923
Surface:	516	1,547
Post-mining (underground):	658	1,033
Post-mining (surface):	<u>129</u>	<u>206</u>
Total:	8,817	11,709

$$\text{Avg.} = (8,817 + 11,709)/2 = 10,263 \text{ million cf}$$

$$10,263 \text{ million cf} \times 20.66 \text{ tons/cf} = 212,034 \text{ million tons CH}_4$$

Table 4-1 - Calculations for Estimating Methane Emissions from Coal Mines

	1 Coal Production (million short tons)	2 Emissions Coefficient (cf/ton)		3 Methane Emitted column 1 x column 2 (million cf methane)	
		Low	High	Low	High
1 Underground Mines					
2 Surface Mines					
3 Post-mining (Underground)					
4 Post-mining (Surface)					
5				Total Low:	Total High:
6				Average:	
7				- CH ₄ Recovered	
8				Total (cf CH ₄):	
9				Total (tons CH ₄):	

WORKBOOK 5

METHANE EMISSIONS FROM LANDFILLS

Landfill gas, consisting primarily of methane (CH_4) and carbon dioxide (CO_2), is produced as a result of the decomposition of organic waste in an anaerobic (without oxygen) environment. Most landfill gas is emitted directly to the atmosphere. However, at a few landfills, the gas is recovered and either flared or used as an energy source. Municipal solid waste (MSW) landfills are estimated to account for over 90 percent of all methane emissions from landfills in the U.S. (EPA 1993). Industrial landfills, which receive nonhazardous waste from factories, processing plants, and other manufacturing activities, account for the remainder of landfill methane emissions.

The following steps may be followed to estimate state methane emissions from landfills: (1) obtain the required data; (2) estimate waste in place at MSW landfills; (3) estimate fraction of waste in large versus small MSW landfills; (4) classify state as nonarid or arid; (5) estimate methane generated from waste in place at small MSW landfills; (6) estimate methane generated from waste in place at large MSW landfills; (7) estimate total methane generated from MSW landfills; (8) estimate methane generated from industrial landfills; (9) adjust for flaring and recovery; and (10) adjust for oxidation.

Step (1) Obtain Required Data

- ***Required Data.*** The information needed to estimate methane emissions from landfills are the following:
 - (1) ***Waste in place in the state.*** For the purposes of this exercise, waste in place is defined as the total quantity of waste that has been landfilled over the previous thirty years. For some states this information may be readily available. If a state does not have information on the quantity of waste in place, waste in place may be estimated based on the *current population of the state*, the *average annual population growth rate* over the past thirty years, the *per-capita waste generation rate* (default values are provided on the following page), and the *portion of waste generated that is landfilled*. For waste in place at industrial landfills, formulas shown in Step 8 may be used if state information is not available.
 - (2) ***Fraction of waste in place in large versus small MSW landfills and number of large landfills in the state.*** For purposes of this exercise, large landfills are those that have a total of more than 1.1 million tons in place. States will need to estimate the fraction of total waste in place that is contained in large landfills. Default values are provided if state information is not available.
 - (3) ***Average annual rainfall within the state.*** A state is considered arid if average rainfall is less than 25 inches per year. The workbook includes a list of those states that receive on average less than 25 inches of rainfall per year (the arid states). All other states are considered to be nonarid.
 - (4) ***Quantity of landfill gas that is flared or recovered for energy purposes.***

- *Data Sources.* State solid waste offices or other agencies may track the amount of waste deposited into landfills. Waste in place may be estimated from this information. Alternatively, population data and default values for waste generation may be used to estimate waste in place. If the data on the percentage of waste generated that is landfilled in each state are not available, they may be obtained from the article "The State of Garbage: 1992 Nationwide Survey" (*BioCycle*, April 1993). The fraction of total waste in place in large and small landfills may be available from state solid waste offices, or may be estimated using the default values shown in this report. Information on methane recovery may be available from state solid waste offices. If not, methane recovery can be estimated using the *Methane Recovery from Landfill Yearbook* (Government Advisory Associates, Inc.), which reports the amount of methane recovered for energy use on a landfill by landfill basis in the U.S.¹ The amount of landfill gas that is flared must be estimated using in-state data, as national data is not available on flaring at landfills.
- *Units for Reporting Data.* Waste in place and the amount of landfill methane flared or recovered for energy purposes should be reported in tons per year.

Step (2) Estimate Waste in Place at MSW Landfills

- If state data on waste in place are available, these data should be used.
- If state data on waste in place are not available, the waste in place may be estimated by using the following formula:

$$\text{Waste in Place (tons)} = \frac{30 \text{ years} \times \text{Current State Population (1,000 head)} \times \text{Per Capita Waste Generation Rate (lbs/capita/yr)} \times \text{Percent Landfilled} \times \text{"Population Growth Correction Factor"} + 2,000 \text{ lbs/ton}}{}$$

Where:

Per Capita Waste Generation Rate is about 1,460 to 1,825 lbs/person/year (4 to 5 lbs/person/day) -- substitute state specific values if available.

Percent Landfilled is 70 percent -- substitute state specific values if available.

Population Growth Correction Factor is based on Table 5-1 and is discussed below.

Population Growth Correction Factor

In most states, the quantity of waste that is landfilled each year has grown significantly over the past 30 years. Therefore, using the current waste landfilled as the amount landfilled each year over the past thirty years could overestimate total waste in place. In order to account for growth in the annual amount of waste deposited, a correction factor is applied. The appropriate correction factor depends on the average amount of time that waste produces methane and on the estimated average annual growth rate in waste landfilled over this period (For example, in the U.S. waste produces methane for about thirty years and so the growth rate of waste landfilled over the previous thirty years must be estimated). One method to

¹ The *Methane Recovery From Landfill Yearbook* is available, for a fee, from Governmental Advisory Associates Inc. (New York, NY), (212) 410-4165.

estimate the average annual growth rate in waste landfilled is to use the average population growth rate. Table 5-1 shows the correction factor to be used for different average annual growth rates and for different time frames for methane production. For example, assuming that waste produces methane for 30 years, the growth correction factor for a state with an average annual population growth rate of 2 percent over the past 30 years would be 75.4 percent.

Table 5-1: Correction Factor for Estimating Waste in Place^a

Average Annual Growth Rate of Landfill Waste Disposal (e.g., Average Annual Growth Rate of Population)							
Growth Rate	1%	2%	3%	4%	5%	6%	7%
Growth Correction Factor	86.5%	75.4%	66.3%	58.8%	52.5%	47.2%	42.8%

a Assuming that waste produces methane for 30 years.

Example Waste in place for a state that has a current population of 2 million and an average annual growth rate over the past thirty years of 2% would be calculated as follows:

$$\begin{aligned}
 \text{Waste in Place} &= 30 \text{ years} \times 2 \text{ million people} \times 75.4\% \text{ correction factor} \times 1,460 \\
 &\quad \text{lbs/person/year} \times 70\% \text{ landfilled} + 2,000 \text{ lbs/ton} \\
 &= 23 \text{ million tons waste in place.}
 \end{aligned}$$

Step (3) Estimate Fraction of Waste in Place in Large Versus Small MSW Landfills

- Once the total quantity of waste in place has been estimated, the next step is to estimate the fraction of total waste in place in large versus small landfills.
- The fraction of waste in large versus small landfills is important because methane generation rates are different due to a variety of factors, such as different waste composition, different waste ages, and ease of moisture movement within the landfill. For this exercise, a large landfill is defined as having more than 1.1 million tons of waste in place.
- Some states may have information on the fraction of waste by landfill size. If these data are not available, then the fraction may be estimated using default values shown in Table 5-2.

Example Assume that total landfilled waste for a state is 25 million tons, of which 20 percent is in small landfills and 80 percent is in large landfills. Therefore, the amount of waste in place in small and large landfills is simply:

$$\text{Waste in place at small landfills: } 20\% \times (25 \text{ million tons}) = 5 \text{ million tons}$$

$$\text{Waste in place at large landfills: } 80\% \times (25 \text{ million tons}) = 20 \text{ million tons}$$

Table 5-2: Default Values for the Fraction of Waste in Large Versus Small Landfills

Region	States Located in Region	Fraction of Waste Landfilled at Large Landfills
Northeast	Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Vermont	89%
Southeast	Alabama, Arkansas, Florida, Georgia, Kentucky, Louisiana, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, West Virginia	73%
Midwest	Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, Oklahoma, North Dakota, South Dakota, Texas, Wisconsin	81%
West	Alaska, Arizona, California, Colorado, Hawaii, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming	86%

Source: Derived from EPA (1988).

Step (4) Classify State as Nonarid or Arid

- Moisture is an important factor in the production of methane in landfills. Landfills in nonarid climates are believed to produce more methane per unit of waste in place than do landfills in arid climates.
- Different methane emission estimates have been developed for nonarid states and for arid states. Table 5-3 lists those states that are classified as arid states -- states that have average rainfall of less than 25 inches per year. All other states are considered to be nonarid states.
- If a state has distinct arid and non-arid areas, then the additional steps described at the end of Steps 5 and 6 should be used.

Table 5-3: Arid States (States with average annual rainfall less than 25 inches)

Arizona	Montana	North Dakota
California	Nebraska	South Dakota
Colorado	Nevada	Utah
Idaho	New Mexico	Wyoming

Source: Department of Commerce (1988)

Step (5) Estimate Methane Generated from Waste in Place at Small MSW Landfills

- The following equations are used to estimate the range of methane generated from small landfills based on the quantity of waste in place. Equation 5.1 should be used for nonarid states and equation 5.2 for arid states. The equation estimates methane emissions in cubic feet per ton per day.

$$\text{Nonarid: Methane (ft}^3/\text{day }) = 0.35 W (\text{tons}) \pm 20\% \quad (5.1)$$

$$\text{Arid: Methane (ft}^3/\text{day }) = 0.27 W (\text{tons}) \pm 20\% \quad (5.2)$$

where W = Waste in place (tons)

- To convert this result to annual methane emissions in tons CH_4 , multiply the result by:

$$\frac{365 (\text{days/year}) \times 19.2 (\text{g/ft}^3)}{453.49 (\text{g/lb}) \times 2,000 (\text{lb/ton})} = 0.0077 \frac{(\text{tonCH}_4/\text{year})}{(\text{ft}^3/\text{day})}$$

Example Methane generated at small landfills for a nonarid state that has waste in place at small landfills of 5.0 million tons would be estimated as follows:

$$\text{Small landfills: } 0.35 (\text{ft}^3/\text{ton/day}) \times 5 \text{ million tons} = 1.75 \text{ million ft}^3/\text{day}$$

$$= 1.75 \text{ million ft}^3/\text{day} \times 0.0077 \frac{(\text{tons CH}_4/\text{yr})}{(\text{ft}^3/\text{day})}$$

$$= 13,475 \text{ million tons CH}_4/\text{yr}$$

- If a state is partially arid, then a weighted average can be used to estimate the methane generated from the landfills. If the amount of landfilled waste in arid and non-arid regions is known, then both equations can be used with the breakdown of waste in place between arid and non-arid regions.

Step (6) Estimate Methane Generated from Waste in Place at Large MSW Landfills

- The method for estimating the range of methane emissions from large landfills is slightly more complex than the method for estimating the range of emissions from small landfills.² The additional steps are 1) estimate the total number of large landfills in the state and, 2) divide total waste in place at large landfills by the total number of large landfills to obtain average waste in place at large landfills. The number of large landfills and the average waste in place at these landfills are then used in the equations to estimate methane generated. Equations 5.3 and 5.4 should be used to estimate methane generated for nonarid states and arid states, respectively. As with equations 5.1 and 5.2, methane generated is in cubic feet per day.

$$\text{Nonarid: Methane (ft}^3/\text{day}) = N \times (419,000 + 0.26 W_{\text{avg}} \text{ (tons)}) \pm 15\% \quad (5.3)$$

$$\text{Arid: Methane (ft}^3/\text{day}) = N \times (419,000 + 0.16 W_{\text{avg}} \text{ (tons)}) \pm 15\% \quad (5.4)$$

Where N = Number of large landfills in the state
 W_{avg} = Average waste in place (tons) at large landfills

- To convert to methane generated in tons per year multiply the result by:

$$\frac{365 \text{ (days/year)} \times 19.2 \text{ (g/ft}^3)}{453.49 \text{ (g/lb)} \times 2,000 \text{ (lb/ton)}} = 0.0077 \frac{\text{tonCH}_4/\text{year}}{(\text{ft}^3/\text{day})}$$

Example Methane generated for an arid state that has 5 large landfills and waste in place at large landfills of 20.0 million tons would be estimated as follows:

- Estimate average waste in place at large landfills

$$W_{\text{avg}} = (20.0 \text{ million}) \text{ tons} / 5 \text{ landfills} = 4.0 \text{ million tons/landfill}$$

- Estimate methane generated at large landfills

$$\begin{aligned} \text{CH}_4 &= 5 \times [419,000 + (0.16 \text{ ft}^3 \text{ CH}_4/\text{day} \times (4.0 \text{ million tons}))] \\ &= 5.295 \text{ million ft}^3 \text{ CH}_4/\text{day} \\ &\quad 5.295 \text{ million ft}^3 \text{ CH}_4/\text{day} \times 0.0077 \frac{(\text{ton CH}_4/\text{yr})}{(\text{ft}^3 \text{ CH}_4/\text{day})} \\ &= 40,770 \text{ million tons CH}_4/\text{yr} \end{aligned}$$

² The accuracy range of the equations for large landfills (± 15 percent) is better than for small landfills (± 20 percent) because the estimate for large landfills is based on a greater number of actual landfill methane production measurements.

- If a state is partially arid, then a weighted average can be used to estimate the methane generated from the landfills. If the exact amount of landfilled waste in arid and non-arid regions is known, then both equations can be used with the breakdown of waste in place between arid and non-arid regions.
- A more accurate, but slightly more complex, method for estimating methane emissions from large landfills may be used when state data are available on the quantity of waste in place at each large landfill in the state. If these data are available, equations 5.5 (for nonarid states) and 5.6 (for arid states) may be used. These equations are slightly modified versions of equations 5.3 and 5.4, respectively.

$$\text{Nonarid: Methane (cf/d)} = \left(\sum_{i=1}^n [419,023 + 0.26 w_i] \right) \pm 15\% \quad (5.5)$$

$$\text{Arid: Methane (cf/d)} = \left(\sum_{i=1}^n [419,023 + 0.16 w_i] \right) \pm 15\% \quad (5.6)$$

Where n = number of large landfills in the state

w_i = waste in place (tons) at each landfill

Step (7) Estimate Total Methane Generated from MSW Landfills

- Total methane generated from MSW landfills is the sum of methane generated at small landfills (Step (5)) and methane generated at large landfills (Step (6)).

Step (8) Estimate Methane Generated from Industrial Landfills

- Methane is also generated from waste deposited into non-hazardous industrial landfills. Although methane generation from non-hazardous industrial landfills is believed to be small relative to MSW landfills, industrial landfill methane generation is still a significant source of methane emissions. Note that methane generation from industrial landfills **does not** include methane generation from industrial waste disposed of into MSW landfills. This methane generation is already accounted for under MSW landfills.
- Precise estimates of the quantity of waste in industrial landfills and its methane generation rate are not available. Based on estimates of the quantity of waste in place at industrial landfills and on the estimated organic content of industrial landfills compared to MSW landfills, EPA (1993) estimated that methane generation from industrial landfills in the U.S. is approximately 7 percent of methane generation from MSW landfills in the U.S. **This 7 percent value may be used to estimate state methane generation from industrial landfills.**
- Alternatively, if state information is available on the quantity of waste in place (WIP) at industrial landfills, the ratio of emissions from industrial landfills to emissions from MSW landfills may be calculated as follows:

$$\frac{\text{Average 15\% organic content} \times \text{WIP at Industrial Landfills}}{\text{Average 65\% organic content} \times \text{WIP at MSW Landfills}}$$

The resulting value would be used in place of the 7 percent default value.

- Total methane generation then equals MSW methane generation (Step (7)) plus industrial landfill methane generation.

Example For a state that has an estimated 0.8 million tons of methane generated from large MSW landfills and 0.2 million tons from small MSW landfills, methane emissions from industrial waste landfills would be calculated as follows:

$$7\% \times (0.8 \text{ million tons CH}_4 + 0.2 \text{ million tons CH}_4) = 0.07 \text{ million tons CH}_4$$

Total methane generated would be: 1 million tons CH₄ from MSW landfills + 0.07 million tons CH₄ from industrial landfills = 1.07 million tons CH₄

Step (9) Adjust for Flaring and Recovery

- Some states have landfills that either flare some of the methane that is produced or recover the methane and use it as an energy source. Methane that is flared or recovered should be subtracted from total methane generated (Step (8)).

Example A state that recovers or flares 0.1 million tons of landfill CH₄ annually and has total methane generation of 1.7 million tons per year would be calculated as follows:

$$1.7 \text{ million tons CH}_4 \text{ generated} - 0.1 \text{ million tons CH}_4 \text{ recovered} = 1.6 \text{ million tons CH}_4$$

Step (10) Adjust for Oxidation

- Not all of the methane that is generated in a landfill is emitted to the atmosphere. Some methane may be oxidized in the top layer of soil over the landfill, and thus not emitted to the atmosphere. The amount of oxidation that occurs is uncertain and depends on the characteristics of the soil and the environment. For purposes of this exercise, it is assumed that 10 percent of the methane generated that is not recovered is oxidized in the soil. Accordingly, **methane generated (minus the amount flared or recovered) (Step (9)) should be multiplied by 90 percent to account for oxidation.**
- Once the adjustment for oxidation has been made, the result is total methane emissions from landfills.

Example Total methane emitted to the atmosphere from landfills for a state with total methane generated of 1.7 million tons and 0.1 million tons of methane recovered would be calculated as follows:

$$\begin{aligned}\text{Total methane emissions:} &= (1.7 \text{ million tons CH}_4 \text{ generated} - 0.1 \text{ million tons CH}_4 \\ &\quad \text{recovered or flared}) \cdot 90\% \text{ oxidized} \\ &= 1.44 \text{ million tons CH}_4\end{aligned}$$

WORKBOOK 6

METHANE EMISSIONS FROM DOMESTICATED ANIMALS

Methane is a natural by-product of animal digestion. During digestion, methane is produced through a process referred to as enteric fermentation in which microbes that reside in animal digestive systems break down feed consumed by the animal. Ruminants, which include cattle, buffalo, sheep, and goats, have the highest methane emissions among all animal types because of their unique digestive system. Ruminants possess a rumen, or large "fore-stomach," in which a significant amount of methane-producing fermentation occurs. Non-ruminant domestic animals, such as pigs and horses, have much lower methane emissions than ruminants because much less methane-producing fermentation takes place in their digestive systems. The amount of methane produced and excreted by an individual animal depends upon its digestive system (*i.e.*, whether or not it possesses a rumen), and the amount and type of feed it consumes.

For cattle, the U.S. EPA used a detailed methodology to estimate emissions for enteric fermentation (U.S. EPA, 1993). The U.S. was divided into five geographic regions based on representative cattle types, diets, and management practices (see Figure 6-1). Nine different cattle types were evaluated in each of the five regions and emissions factors were estimated for each using a mechanistic model of rumen digestion (see Table 6-1).

Using the results of the EPA analysis, estimating methane emissions from domesticated animals requires three steps: 1) obtain data on animal populations; 2) identify geographic region and corresponding emissions factor; and 3) multiply animal populations by their appropriate emissions factor. These three steps are outlined below. An alternative approach that requires specific livestock characteristics is outlined in Discussion Section 6. Since cattle characteristics may vary significantly by state, it is recommended that states with large cattle populations consider using the alternative approach if the state cattle characteristics differ from the cattle characteristics used in the EPA study.

Step (1): Obtain Required Data

- *Required Data.* The information needed to estimate methane emissions from domesticated animals is annual average animal populations¹ for the following animals: cattle (by type; see Table 6-1), buffalo, sheep, goats, swine, horses, mules, and asses.
- *Data Source.* Departments within each state responsible for conducting agricultural research and overseeing the agricultural sector should be able to provide state animal populations. Additionally, state animal populations can be found in the *Census of Agriculture, Volume 1: Geographic Area Series*, published by the Bureau of the Census. Also, if requested, the USDA can produce state by state inventories on domesticated animal populations.
- *Units for Reporting Data.* Animal population should be reported in number of head.

¹ Please note that animal populations fluctuate during the year, in some cases by large amounts. For example, a census done before calving will give a much smaller number than a census done after calving. The annual average animal population should be used in the estimates.

Example According to the 1992 Census of Agriculture, the number of milk cows in Ohio were **295,677 head**.

Step (2): Identify Geographic Region

- Determine which of the five geographic regions, defined in Figure 6-1, the state falls into. The emissions factors corresponding to the region are to be used for Step 3.

Example The state of Ohio falls in the **North Central Region**.

Step (3): Estimate Methane Emissions

- Multiply each animal population by the appropriate regional emissions factor. Emissions factors for cattle are presented in Table 6-1. Emissions factors for all other animals are presented in Table 6-2.

$$\text{Animal Population (head)} \times \text{Regional Emissions Factor (lbs. CH}_4/\text{head)} = \text{Methane Emissions (lbs.)}$$

- For each animal, divide the results by 2000 lbs/ton to obtain tons of methane. Sum across all animal types to obtain total methane emissions from domesticated animals.

Example Methane emissions from milk cows in Ohio for 1992 are calculated as follows:

$$(a) 295,677 \text{ head} \times 240.7 \text{ (lbs CH}_4/\text{head)} = 71,169,454 \text{ lbs CH}_4$$

$$(b) 71,169,454 \text{ lbs CH}_4 \div 2000 \text{ (lbs/ton)} = 35,585 \text{ tons CH}_4$$

Figure 6-1

Geographic Regions

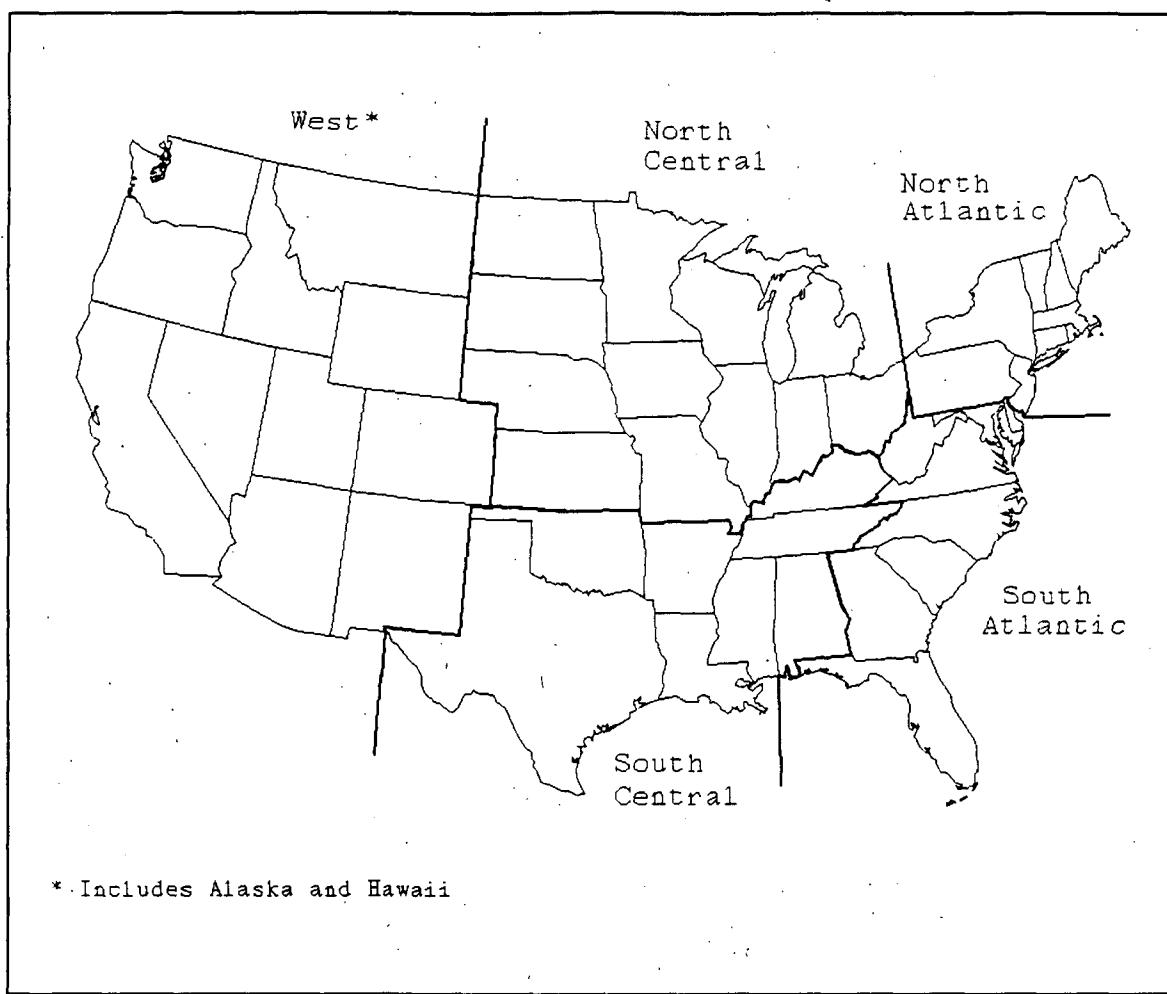


Table 6-1. Emissions Factors for U.S. Cattle by Region (lbs CH₄/head/yr)

Animal Type/Region	North Atlantic	South Atlantic	North Central	South Central	West	National Average ^e
Dairy Cattle						
Replacements 0-12 months ^a	42.9	45.1	41.6	44.7	45.5	43.1
Replacements 12-24 months ^a	128.5	129.1	126.3	135.7	134.6	129.4
Mature Cows	258.5	278.3	240.7	257.7	262.5	252.1
Beef Cattle						
Replacements 0-12 months ^a	42.2	49.9	44.8	51.9	49.9	49.1
Replacements 12-24 months ^a	140.4	148.5	133.8	148.9	142.7	143.0
Mature Cows	135.3	154.0	130.9	155.9	152.0	146.7
Weanling System Steers/Heifers ^b	NA ^c	NA	49.7	52.8	51.7	50.8
Yearling System Steers/Heifers ^d	NA	NA	103.4	104.7	104.7	104.1
Bulls	220	220	220	220	220	220

a A portion of the offspring are retained to replace mature cows that die or are removed from the herd (culled) each year. Those that are retained are called "replacements."

b In "weanling systems," calves are moved directly from weaning to confined feeding programs. This system represents a very fast movement of cattle through to marketing. Weanling system cattle are marketed at about 420 days of age (14 months).

c These cattle types are typically not found in the North Atlantic and South Atlantic regions. If desired, it is appropriate to use the national total emissions factor for these regions.

d "Yearling systems" represent a relatively slow movement of cattle through to marketing. These systems include a wintering over, followed by a summer of grazing on pasture. Yearling system cattle are marketed at 565 days of age (18.8 months).

e National Averages are weighted by regional populations as of 1990.

Source: U.S. EPA, 1993.

**Table 6-2
Emissions Factors for Other Animals (All Regions)**

Animal	Emissions Factor (lbs CH ₄ /head/yr)
Sheep	17.6
Goats	11.0
Pigs	3.3
Horses	39.6
Mules/Asses	48.5

Sources: Emissions factors from Crutzen et al. (1986).

WORKBOOK 7

METHANE EMISSIONS FROM MANURE MANAGEMENT

When animal manure decomposes in an anaerobic environment, decomposition of the organic material in the manure produces methane. The way in which manure is managed is the most important factor affecting the amount of methane produced, since certain types of storage and treatment systems promote an oxygen-free environment. In particular, liquid systems, e.g., lagoons, ponds, tanks, or pits, tend to produce a significant quantity of methane. When manure is handled as a solid or when it is deposited on pastures and rangelands, it tends to decompose aerobically and produce little or no methane. Higher temperatures and moist climatic conditions also promote methane production. Only manure from animals managed by humans for production of animal products is included in the workbook calculations (*i.e.*, wild animals are excluded).

To estimate methane emissions from animal manure, the following steps should be performed: 1) obtain the required data on animal populations and manure management practices; 2) calculate the amount of volatile solids (VS) produced by each animal; 3) estimate methane emissions from each manure management system; 4) convert emissions to tons of methane; and 5) sum estimates to obtain total annual methane emissions for the state. Each of these steps is outlined in detail below. A worksheet is provided in Table 7-13 to assist in the calculations. A more detailed description of the methodology is provided in Discussion Section 7.

Step (1) Obtain Required Data

- *Required Data.* The information needed to estimate methane emissions from manure is animal populations for the following animal types: cattle (by type), swine (by type), poultry (by type), sheep, goats, donkeys, horses, and mules (see Exhibit 7-1 for further detail).

In addition, data on the percentage of animal manure handled in each manure management system are required. A list and description of the major livestock manure systems in use in the U.S. appear in Discussion Section 7.

- *Data Sources.* Departments within each state responsible for conducting agricultural research and monitoring agricultural waste practices should be consulted for animal population data. Alternatively, animal population data are provided by the Agriculture Statistics Board of the USDA. Also, these data can be found in the *Census of Agriculture, Volume 1: Geographic Area Series*, published by the Bureau of the Census. Manure management usage percentages for most states and management practices are provided in Tables 7-1 to 7-9.
- *Units for Reporting Data.* Animal population should be reported in number of head. Manure management usage should be reported as percentages.

Exhibit 7-1

Recommended Representative Animal Types

Main Categories	Sub-Categories
Mature Dairy Cattle	Milk Cows: used principally for commercial milk production
Mature Non-Dairy Cattle	Mature Females: -- Beef Cows: used principally for producing beef steers and heifers -- Multiple-Use Cows: used for milk production, draft power, and other uses Mature Males: -- Breeding Bulls: used principally for breeding purposes -- Draft Bullocks: used principally for draft power
Young Cattle	Pre-Weaned Calves Growing Heifers, Steers/Bullocks and Bulls Feedlot-Fed Steers and Heifers on High-Grain Diets
Swine	Market: used principally for commercial pork products. Breeding: used principally for breeding.
Poultry	Layers Broilers Ducks Turkeys
Other Animals	Sheep Goats Donkeys Horses/Mules

Step (2) Calculate the Amount of Volatile Solids (VS) Produced. (Table 7-13, Columns A, B, C and D)

- For each animal type i , multiply the animal population by the typical animal mass (TAM_i) and the average annual volatile solids production per unit of animal mass (vs_i). Values for the TAM and vs for each of the animal types are provided in Table 7-10.

$$\text{Animal}_i \text{ Population (head)} \times TAM_i \text{ (lbs/head)} \times vs_i \text{ (lbs VS/lb animal mass/yr)} \\ = \text{Total VS}_i \text{ produced (lbs/yr)}$$

Example According to the 1992 Census of Agriculture, the number of milk cows in Ohio were 295,677 head. According to Table 7-2, the percentage of this manure handled in daily spread manure management systems is 45% for Ohio.

Example The total amount of volatile solids (VS) produced by milk cows in Ohio for 1992 is calculated as follows:

$$295,677 \text{ head} \times 1,345 \text{ lbs/hd.} \times 3.65 \text{ lbs VS/lb animal mass/yr} = 1.45 \text{ billion lbs/yr}$$

Step (3) Estimate Methane Emissions for Each Manure Management System (Table 7-13, Columns E, F, G, H and I)

- For each animal type i and manure system j , multiply the amount of volatile solids produced (VS_i) by the methane producing capacity of the manure (B_{oi}) times the methane producing potential (MCF_j) of the manure system times the percent of the animals' manure that is managed in that manure system ($WS\%_{ij}$). Default values for B_o and MCF by state are presented in Tables 7-11 to 7-12. WS% values for most states and management practices are provided in Tables 7-1 to 7-9.

$$VS_i \times B_{oi} \times MCF_j \times WS\%_{ij} = \text{Methane Emissions for animal } i \text{ in system } j \text{ (ft}^3 \text{ CH}_4\text{)}$$

where:

- | | | |
|-------------|---|---|
| VS_i | = | total volatile solids produced (lbs/yr) for animal i ; |
| B_{oi} | = | maximum methane producing capacity per pound of VS for animal i ($\text{ft}^3/\text{lb-VS}$); |
| MCF_j | = | methane conversion factor for each manure system j (%); |
| $WS\%_{ij}$ | = | percent of animal i 's manure managed in manure system j (%). |

Example Total annual methane emissions from milk cows in Ohio on a daily spread manure management system is calculated as follows:

$$1.45 \text{ billion lbs/yr} \times 3.84 \text{ (ft}^3 \text{ CH}_4/\text{lb-VS)} \times 0.2\% \times 45\% = 5.01 \text{ million ft}^3 \text{ CH}_4/\text{yr}$$

Step (4) Convert to Tons of Methane (Table 7-3, Column J)

- For each animal i and manure management system j multiply methane emissions by the density of methane (0.0413 lbs/ ft^3) to convert from cubic feet to pounds.
- Divide the results by 2000 to obtain methane emissions from each animal and manure management system in tons.

Example Annual methane emissions from milk cows in Ohio in a daily spread manure management system [from Step(3)] are converted from cubic feet to pounds as follows:

$$(a) 5.01 \text{ million ft}^3 \text{ CH}_4/\text{yr} \times 0.0413 \text{ lbs}/\text{ft}^3 = 206,913 \text{ lbs CH}_4/\text{yr}$$

$$(b) 206,913 \text{ lbs CH}_4/\text{yr} \div 2000 \text{ lbs/ton} = 103.5 \text{ tons CH}_4/\text{yr}$$

Step (5) Estimate Total Annual Methane Emissions

- Sum across all manure management systems j and all animal types i to obtain total methane emissions from animal manure.

$$\text{Total Annual Methane Emissions (tons CH}_4) = \sum_i \sum_j \text{Total Methane Emissions}_{ij} \text{ (tons)}$$

TABLE 7-1: MANURE MANAGEMENT SYSTEMS FOR U.S. BEEF

STATE	An.Lag.	Drylot	Liq/Slur	Pasture	Other
AL	0%	2%	0%	98%	0%
AK	0%	0%	0%	100%	0%
AZ	0%	30%	0%	70%	0%
AR	0%	1%	0%	99%	0%
CA	0%	12%	0%	88%	0%
CO	0%	25%	0%	72%	3%
CT	0%	0%	0%	100%	0%
DE	0%	0%	0%	100%	0%
FL	0%	0%	0%	99%	0%
GA	0%	1%	0%	99%	0%
HI	0%	10%	0%	90%	0%
ID	0%	13%	1%	86%	0%
IL	2%	14%	2%	83%	0%
IN	1%	17%	1%	81%	0%
IA	0%	13%	0%	87%	0%
KS	2%	23%	0%	76%	0%
KY	0%	1%	0%	99%	0%
LA	0%	1%	0%	99%	0%
ME	0%	0%	0%	100%	0%
MD	0%	4%	1%	95%	0%
MA	0%	0%	0%	100%	0%
MI	2%	22%	2%	75%	0%
MN	0%	13%	1%	85%	0%
MS	0%	1%	0%	99%	0%
MO	1%	1%	0%	98%	0%
MT	0%	3%	0%	97%	0%
NE	1%	31%	0%	68%	0%
NV	0%	5%	0%	95%	0%
NH	0%	0%	0%	100%	0%
NJ	0%	6%	0%	94%	0%
NM	0%	8%	0%	92%	0%
NY	0%	2%	0%	97%	0%
NC	0%	0%	1%	97%	1%
ND	0%	2%	0%	98%	0%
OH	1%	12%	1%	87%	0%
OK	0%	5%	0%	95%	0%
OR	0%	5%	0%	94%	0%
PA	0%	6%	0%	94%	0%
RI	0%	0%	0%	100%	0%
SC	0%	3%	0%	97%	0%
SD	1%	5%	0%	94%	0%
TN	0%	1%	0%	99%	0%
TX	0%	13%	0%	87%	0%
UT	0%	5%	0%	95%	0%
VT	0%	0%	0%	100%	0%
VA	0%	2%	0%	98%	0%
WA	0%	15%	0%	85%	0%
WV	0%	2%	0%	98%	0%
WI	0%	5%	0%	95%	0%
WY	0%	6%	0%	94%	0%
U.S. Average	<1%	10%	<1%	89%	0%

* An. Lag. stands for anaerobic lagoon.

TABLE 7-2: MANURE MANAGEMENT SYSTEMS FOR U.S. DAIRY

STATE	An. Lagoon	Liq/ Slurry	Daily Spread	Solid Stor.	Other
AL	50%	0%	50%	0%	0%
AK	10%	71%	2%	2%	15%
AZ	50%	0%	0%	0%	50%
AR	25%	0%	75%	0%	0%
CA	40%	0%	0%	0%	60%
CO	5%	10%	85%	0%	0%
CT	0%	53%	47%	1%	0%
DE	5%	35%	60%	0%	0%
FL	30%	0%	10%	0%	60%
GA	35%	5%	5%	0%	55%
HI	31%	57%	6%	0%	6%
ID	10%	85%	2%	0%	3%
IL	5%	15%	45%	10%	25%
IN	10%	60%	20%	10%	0%
IA	3%	20%	8%	65%	4%
KS	0%	40%	60%	0%	0%
KY	19%	8%	30%	0%	43%
LA	6%	0%	4%	0%	90%
ME	0%	29%	58%	13%	0%
MD	2%	48%	45%	5%	0%
MA	0%	29%	58%	13%	0%
MI	5%	30%	45%	12%	8%
MN	0%	30%	40%	30%	0%
MS	10%	1%	2%	2%	85%
MO	60%	0%	40%	0%	0%
MT	12%	19%	39%	23%	7%
NE	0%	5%	35%	0%	60%
NV	40%	10%	0%	50%	0%
NH	0%	40%	20%	40%	0%
NJ	0%	29%	58%	13%	0%
NM	90%	0%	10%	0%	0%
NY	0%	20%	70%	10%	0%
NC	20%	20%	50%	10%	0%
ND	1%	1%	8%	90%	0%
OH	5%	30%	45%	12%	8%
OK	15%	0%	5%	0%	80%
OR	42%	35%	5%	1%	17%
PA	0%	2%	95%	3%	0%
RI	0%	29%	58%	13%	0%
SC	80%	5%	10%	5%	0%
SD	25%	25%	30%	20%	0%
TN	5%	40%	20%	0%	35%
TX	25%	10%	15%	50%	0%
UT	1%	1%	8%	90%	0%
VT	0%	29%	58%	13%	0%
VA	0%	75%	25%	0%	0%
WA	40%	50%	10%	0%	0%
WV	2%	40%	30%	20%	8%
WI	0%	15%	70%	15%	0%
WY	12%	19%	39%	23%	7%
U.S. Average	11%	21%	41%	18%	8%

TABLE 7-3: MANURE MANAGEMENT SYSTEMS FOR U.S. SWINE

STATE	An.	Drylot	Pit St.	Pit St.	Other
	Lagoon		<1 mnth	>1 mnth	
AL	90%	0%	0%	10%	0%
AK	100%	0%	0%	0%	0%
AZ	100%	0%	0%	0%	0%
AR	70%	20%	0%	10%	0%
CA	90%	0%	0%	0%	10%
CO	24%	25%	21%	24%	6%
CT	15%	0%	0%	0%	85%
DE	20%	10%	0%	70%	0%
FL	35%	64%	1%	0%	0%
GA	68%	20%	0%	10%	2%
HI	32%	7%	17%	36%	8%
ID	40%	15%	5%	35%	5%
IL	25%	15%	10%	45%	5%
IN	25%	10%	5%	60%	0%
IA	3%	30%	11%	39%	13%
KS	30%	40%	0%	30%	0%
KY	80%	12%	7%	1%	0%
LA	95%	5%	0%	0%	0%
ME	3%	53%	2%	42%	0%
MD	50%	10%	0%	40%	0%
MA	3%	53%	2%	42%	0%
MI	42%	12%	4%	39%	3%
MN	0%	20%	20%	40%	20%
MS	59%	14%	5%	9%	13%
MO	80%	20%	0%	0%	0%
MT	0%	40%	25%	25%	10%
NE	35%	5%	55%	5%	0%
NV	25%	75%	0%	0%	0%
NH	5%	90%	0%	5%	0%
NJ	3%	53%	2%	42%	0%
NM	10%	70%	10%	10%	0%
NY	5%	30%	5%	60%	0%
NC	70%	15%	0%	15%	0%
ND	20%	20%	30%	30%	0%
OH	37%	8%	1%	46%	8%
OK	60%	30%	10%	0%	0%
OR	25%	6%	35%	12%	22%
PA	0%	39%	1%	60%	0%
RI	3%	53%	2%	42%	0%
SC	90%	5%	0%	5%	0%
SD	20%	30%	25%	25%	0%
TN	80%	15%	0%	5%	0%
TX	45%	30%	15%	10%	20%
UT	75%	25%	0%	0%	0%
VT	3%	53%	2%	42%	0%
VA	90%	0%	0%	10%	0%
WA	30%	0%	10%	60%	0%
WV	25%	25%	25%	25%	0%
WI	0%	10%	20%	70%	0%
WY	24%	25%	21%	24%	6%
U.S. Average	29%	20%	12%	32%	7%

TABLE 7-4: MANURE MANAGEMENT SYSTEMS FOR U.S. CAGED LAYERS

STATE	An. Lagoon	Deep Pit	Liq/ Slurry	Other
AL	80%	10%	10%	0%
AK	15%	63%	12%	10%
AZ	0%	100%	0%	0%
AR	40%	0%	60%	0%
CA	7%	45%	3%	45%
CO	4%	88%	8%	0%
CT	0%	100%	0%	0%
DE	0%	100%	0%	0%
FL	12%	70%	6%	12%
GA	1%	30%	5%	65%
HI	80%	10%	0%	10%
ID	0%	40%	60%	0%
IL	10%	90%	0%	0%
IN	0%	95%	5%	0%
IA	2%	90%	4%	4%
KS	0%	100%	0%	0%
KY	61%	3%	33%	3%
LA	95%	0%	0%	5%
ME	0%	81%	9%	10%
MD	0%	100%	0%	0%
MA	0%	81%	9%	10%
MI	3%	85%	3%	10%
MN	0%	75%	25%	0%
MI	85%	0%	5%	10%
MO	0%	80%	20%	0%
MT	4%	88%	8%	0%
NE	0%	100%	0%	0%
NV	0%	75%	0%	25%
NH	0%	100%	0%	0%
NJ	0%	81%	9%	10%
NM	20%	45%	10%	25%
NY	0%	60%	30%	10%
NC	30%	15%	5%	50%
ND	5%	90%	5%	0%
OH	0%	100%	0%	0%
OK	0%	80%	20%	0%
OR	11%	80%	9%	0%
PA	0%	65%	5%	30%
RI	0%	81%	9%	10%
SC	40%	50%	0%	10%
SD	20%	80%	0%	0%
TN	7%	3%	90%	0%
TX	40%	10%	0%	50%
UT	0%	50%	0%	50%
VT	0%	81%	9%	10%
VA	0%	30%	0%	70%
WA	0%	90%	10%	0%
WV	0%	0%	0%	100%
WI	0%	55%	5%	40%
WY	4%	88%	8%	0%
U.S. Average	14%	56%	10%	20%

TABLE 7-5: MANURE MANAGEMENT SYSTEMS FOR U.S. BROILERS

State	Litter	Other
AL	100%	0%
AK		
AZ		
AR	100%	0%
CA	100%	0%
CO		
CT		
DE	100%	0%
FL	100%	0%
GA	100%	0%
HI	100%	0%
ID		
IL		
IN		
IA	100%	0%
KS		
KY	100%	0%
LA		
ME		
MA		
MD	100%	0%
MI	100%	0%
MN	100%	0%
MS	100%	0%
MO	100%	0%
MT		
NC	100%	0%
ND		
NH		
NJ		
NM		
NY	100%	0%
NE	100%	0%
NV		
OH	100%	0%
OK	100%	0%
OR	100%	0%
PA	100%	0%
RI		
SC	100%	0%
SD		
TN	100%	0%
TX	100%	0%
UT		
VA	100%	0%
VT		
WV	100%	0%
WA	100%	0%
WI	100%	0%
WY		
Other	100%	0%
U.S. Average	100%	0%

TABLE 7-6: MANURE MANAGEMENT SYSTEMS FOR U.S. TURKEYS

State	Litter	Range	Other
AR	95%	5%	0%
AK			
AZ			
AR			
CA	93%	7%	0%
CO			
CT	0%	100%	0%
DE			
FL			
GA	50%	50%	0%
HI			
ID			
IL	85%	15%	0%
IN	95%	5%	0%
IA	100%	0%	0%
KS	100%	0%	0%
KY			
LA			
ME			
MA	75%	25%	0%
MD	90%	10%	0%
MI	93%	7%	0%
MN	100%	0%	0%
MS			
MO	100%	0%	0%
MT			
NC	90%	10%	0%
ND	40%	60%	0%
NH	100%	0%	0%
NJ	75%	25%	0%
NM			
NY	100%	0%	0%
NE	100%	0%	0%
NV			
OH	100%	0%	0%
OK			
OR	100%	0%	0%
PA	90%	10%	0%
RI			
SC	95%	5%	0%
SD	100%	0%	0%
TN			
TX			
UT	0%	100%	0%
VA	94%	6%	0%
VT			
WV	90%	10%	0%
WA			
WI			
WY			
Other	88%	12%	0%
U.S. Average	92%	8%	0%

TABLE 7-7: MANURE MANAGEMENT SYSTEMS FOR U.S. SHEEP

STATE	Pasture	Other
AL		
AK	100%	0%
AZ	100%	0%
AR		
CA	90%	10%
CO	95%	5%
CT	50%	50%
DE		
FL		
GA		
HI		
ID	95%	5%
IL	95%	5%
IN	90%	10%
IA	99%	1%
KS	100%	0%
KY	95%	5%
LA	100%	0%
ME	66%	34%
MD	66%	34%
MA	66%	34%
MI	94%	6%
MN	90%	10%
MS		
MO	90%	10%
MT	98%	2%
NE	90%	10%
NV	98%	2%
NH	100%	0%
NJ	66%	34%
NM	100%	0%
NY	65%	35%
NC	98%	2%
ND	95%	5%
OH	95%	5%
OK	100%	0%
OR	91%	9%
PA	50%	50%
RI		
SC		
SD	100%	0%
TN	100%	0%
TX	80%	20%
UT	95%	5%
VT	66%	34%
VA	100%	0%
WA	100%	0%
WV	90%	10%
WI	97%	3%
WY	95%	5%
Other	100%	
U.S. Average		92%
		8%

TABLE 7-8: MANURE MANAGEMENT SYSTEMS FOR U.S. GOATS

STATE	Pasture	Other
AL		
AK	100%	0%
AZ		
AR		
CA		
CO	100%	0%
CT	100%	0%
DE		
FL		
GA		
HI		
ID		
IL	100%	0%
IN	100%	0%
IA	100%	0%
KS	100%	0%
KY	99%	1%
LA	100%	0%
ME	100%	0%
MD	100%	0%
MA	100%	0%
MI	99%	1%
MN	100%	0%
MS		
MO	100%	0%
MT	99%	1%
NE	100%	0%
NV	98%	2%
NH	100%	0%
NJ	100%	0%
NM	100%	0%
NY	100%	0%
NC	90%	10%
ND	100%	0%
OH	100%	0%
OK	100%	0%
OR	84%	16%
PA	100%	0%
RI	100%	0%
SC	100%	0%
SD	100%	0%
TN	100%	0%
TX	80%	20%
UT	100%	0%
VT	100%	0%
VA	99%	1%
WA	100%	0%
WV	80%	20%
WI	95%	5%
WY	100%	0%
Other		
U.S. Average		84%
		16%

TABLE 7-9: MANURE MANAGEMENT SYSTEMS FOR U.S. HORSES

STATE	Paddock	Pasture	Other
AL	50%	50%	0%
AK	10%	90%	0%
AZ	35%	65%	0%
AR	10%	90%	0%
CA	20%	80%	0%
CO	17%	83%	0%
CT	50%	50%	0%
DE	50%	50%	0%
FL	15%	60%	25%
GA	33%	60%	7%
HI	45%	55%	0%
ID	35%	60%	5%
IL	30%	40%	30%
IN	50%	50%	0%
IA	8%	92%	0%
KS	10%	90%	0%
KY	30%	70%	0%
LA	25%	75%	0%
ME	35%	65%	0%
MD	35%	65%	0%
MA	35%	65%	0%
MI	36%	64%	0%
MN	50%	50%	0%
MS	40%	60%	0%
MO	10%	90%	0%
MT	1%	99%	0%
NE	5%	95%	0%
NV	20%	80%	0%
NH	90%	10%	0%
NJ	35%	65%	0%
NM	75%	25%	0%
NY	50%	25%	25%
NC	10%	65%	25%
ND	30%	70%	0%
OH	95%	5%	0%
OK	20%	80%	0%
OR	45%	55%	0%
PA	50%	50%	0%
RI	35%	65%	0%
SC	50%	50%	0%
SD	20%	80%	0%
TN	25%	75%	0%
TX	0%	60%	40%
UT	20%	80%	0%
VT	35%	65%	0%
VA	1%	99%	0%
WA	50%	50%	0%
WV	75%	25%	0%
WI	15%	50%	35%
WY	17%	83%	0%
U.S. Average	27%	66%	7%

Table 7-10. U.S. Average Animal Size and VS Production

Animal Type		Typical Animal Mass(TAM) lbs	Volatile Solids (vs) lbs VS/ lb animal mass/yr
Feedlot Beef Cattle	Steers/Heifers	915	2.6
Other Beef Cattle	Calves	397	2.6
	Heifers	794	2.6
	Steers	794	2.6
	Cows	1102	2.6
	Bulls	1587	2.6
Dairy Cattle	Heifers	903	3.65
	Cows	1345	3.65
Swine	Market	101	3.1
	Breeding	399	3.1
Poultry	Layers	3.5	4.4
	Broilers	1.5	6.2
	Ducks	3.1	6.75
	Turkeys	7.5	3.32
Other	Sheep	154	3.36
	Goats	141	3.48
	Donkeys	661	3.65
	Horses and Mules	992	3.65

Table 7-11. Maximum Methane Producing Capacity for U.S. Estimates

Animal Type	Category	Maximum Potential Emissions (B_o) (ft ³ CH ₄ /lb-VS)
Cattle	Beef in Feedlots	5.29
	Beef Not in Feedlots	2.72
	Dairy	3.84
Swine	Breeder	5.77
	Market	7.53
Poultry	Layers	5.45
	Broilers	4.81
	Turkeys	4.81
	Ducks	5.13
Sheep	In Feedlots	5.77
	Not in Feedlots	3.04
Goats		2.72
Horses & Mules		5.29

Table 7-12. Methane Conversion Factors for U.S. Livestock Manure Systems

State	Pasture, Range & Paddocks	Drylot	Solid Storage	Daily Spread	Liquid/ Slurry
Alabama	1.4%	1.9%	1.4%	0.4%	29.0%
Arizona	1.4%	1.9%	1.4%	0.4%	28.9%
Arkansas	1.3%	1.8%	1.3%	0.4%	27.6%
California	1.2%	1.4%	1.2%	0.3%	21.9%
Colorado	0.9%	1.0%	0.9%	0.2%	18.2%
Connecticut	0.9%	1.0%	0.9%	0.2%	18.5%
Delaware	1.2%	1.4%	1.2%	0.3%	22.6%
Florida	1.5%	2.4%	1.5%	0.6%	38.6%
Georgia	1.4%	1.8%	1.4%	0.4%	29.0%
Idaho	0.8%	0.8%	0.8%	0.2%	15.5%
Illinois	1.1%	1.3%	1.1%	0.3%	22.8%
Indiana	1.0%	1.2%	1.0%	0.3%	21.5%
Iowa	0.9%	1.1%	0.9%	0.2%	20.7%
Kansas	1.1%	1.5%	1.1%	0.3%	24.7%
Kentucky	1.2%	1.5%	1.2%	0.3%	23.8%
Louisiana	1.4%	2.1%	1.4%	0.5%	32.5%
Maine	0.8%	0.8%	0.8%	0.2%	15.5%
Maryland	1.1%	1.2%	1.1%	0.3%	21.0%
Massachusetts	0.9%	1.0%	0.9%	0.2%	18.1%
Michigan	0.8%	0.9%	0.8%	0.2%	17.0%
Minnesota	0.8%	0.8%	0.8%	0.2%	18.0%
Mississippi	1.4%	1.9%	1.4%	0.4%	29.3%
Missouri	1.1%	1.4%	1.1%	0.3%	24.1%
Montana	0.7%	0.8%	0.7%	0.2%	15.8%
Nebraska	1.0%	1.1%	1.0%	0.2%	20.8%
Nevada	1.2%	1.4%	1.2%	0.3%	22.1%
New Hampshire	0.8%	0.8%	0.8%	0.2%	16.3%
New Jersey	1.0%	1.1%	1.0%	0.3%	20.6%
New Mexico	1.2%	1.3%	1.2%	0.3%	21.3%
New York	0.9%	0.9%	0.9%	0.2%	18.1%
North Carolina	1.3%	1.5%	1.3%	0.3%	24.5%
North Dakota	0.7%	0.7%	0.7%	0.2%	16.8%
Ohio	1.0%	1.1%	1.0%	0.2%	20.2%
Oklahoma	1.4%	1.9%	1.4%	0.4%	28.7%
Oregon	1.1%	1.1%	1.1%	0.2%	16.2%
Pennsylvania	0.9%	1.0%	0.9%	0.2%	18.7%
Rhode Island	1.0%	1.1%	1.0%	0.2%	18.7%
South Carolina	1.3%	1.7%	1.3%	0.4%	27.3%
South Dakota	0.8%	0.9%	0.8%	0.2%	19.1%
Tennessee	1.3%	1.6%	1.3%	0.3%	24.8%
Texas	1.4%	2.1%	1.4%	0.5%	31.7%
Utah	0.9%	1.0%	0.9%	0.2%	17.4%
Vermont	0.8%	0.8%	0.8%	0.2%	16.6%
Virginia	1.2%	1.4%	1.2%	0.3%	22.5%
Washington	1.0%	1.0%	1.0%	0.2%	15.5%
West Virginia	1.2%	1.3%	1.2%	0.3%	21.4%
Wisconsin	0.8%	0.8%	0.8%	0.2%	17.0%
Wyoming	0.8%	0.8%	0.8%	0.2%	15.9%

Other Systems: Pit Storage for less than 30 days is assumed to have an MCF equal to 50% of the MCF for Liquid/Slurry. Pit Storage for more than 30 days is assumed to have an MCF equal to liquid/slurry. Anaerobic lagoons are assumed to have an MCF of 90%; litter and deep pit stacks an MCF of 10%.

Table 7-13 Worksheet to Calculate Methane Emissions from Animal Manure

<u>Animal Type</u>	<i>Input</i>	<i>Input</i>	<i>Input</i>	$(A)x(B)x(C)$	<i>Input</i>	$(D) \times (E)$
	(A) Population <u>(head)</u>	(B) Typical Animal Mass (TAM) <u>(lbs/head)</u>	(C) Volatile Solids (vs) <u>(lbs VS/lb mass)</u>	(D) Total VS Produced <u>(lbs)</u>	(E) CH ₄ Producing Capacity (Bo) <u>(cubic ft/lb-VS)</u>	(F) Max. Potential Emissions <u>(cubic ft)</u>

<u>Manure System</u>	<i>Input</i>	<i>Input</i>	$(F)x(G)x(H)$	$(I) \times 0.0413$
	(G) Methane Conv. Factor (MCF) <u>(%)</u>	(H) Waste System Usage (WS%) <u>(%)</u>	(I) Methane Emissions <u>(cubic ft)</u>	(J) Methane Emissions <u>(lbs)</u>
	Pasture/Range			
Daily Spread				
Solid Storage				
Drylot				
Deep Pit Stacks				
Litter				
Paddock				
Liquid/Slurry				
Anaerobic Lagoon				
Pit Storage < 1 mo				
Pit Storage > 1 mo				

Total Methane Emissions (tons/yr):

[Sum Column (10) and divide by 2000]

WORKBOOK 8

METHANE EMISSIONS FROM FLOODED RICE FIELDS

When fields are flooded, anaerobic conditions in the soils develop, and methane is produced through anaerobic decomposition of soil organic matter. Methane is released primarily through the rice plants, which act as conduits from the soil to the atmosphere. Non-flooded rice fields, such as dry upland rice fields, do not produce significant quantities of CH₄, however. Additionally, deepwater, floating rice fields (>3.3 feet floodwater depth) are not believed to produce significant quantities of CH₄. Accordingly, only flooded, non-deepwater, rice fields are accounted for in these calculations.

Only seven U.S. states produce significant quantities of rice: Arkansas, California, Florida, Louisiana, Mississippi, Missouri, and Texas. Other states may skip this section of the workbook.

To estimate methane emissions from flooded rice fields, the following steps are required: 1) obtain the required data on area harvested; 2) calculate the average number of acre-days harvested annually (both low and high); and 3) apply an emissions rate range to the annual harvested non-deepwater, wetland area. These steps are outlined in detail below. A more detailed description of the methodology is provided in Discussion Section 8.

Step (1) Obtain Required Data

- *Required Data.* The information needed to calculate methane emissions from flooded rice fields is the total area harvested (not including upland or deepwater rice fields) for three consecutive years centered on the study year (e.g., to calculate 1990 emissions, data from 1989, 1990, and 1991 are needed), and the length of the growing season (both low and high).
- *Data Source.* State agencies responsible for overseeing the agricultural sector should be consulted. Alternatively, rice area harvested for the major rice producing states can be found in the U.S. Department of Agriculture's annual *Crop Production* report.
- *Units for Reporting Data.* Rice area harvested should be reported in acres, while the length of the growing season should be in days. (Table 8-1 provides the range of flooding season lengths by state).

Step (2) Calculate the Average Number of Acre-Days Harvested Annually

- Calculate the 3-year average area harvested for the base year.

$$\begin{aligned} & (\text{Area Harvested Year 1} + \text{Area Harvested Year 2} + \text{Area Harvested Year 3}) + 3 \\ & \qquad\qquad\qquad = \text{Average Area Harvested Base Year 2} \end{aligned}$$

Table 8-1. Growing Season Lengths by State

State	Growing Season Length (days)	
	Low	High
Arkansas	75	100
California	123	153
Florida ^a primary ratoon	90	120
Louisiana ^a primary ratoon	90	120
Mississippi	75	82
Missouri	80	100
Texas ^a primary ratoon	60	80

a These states have a second, or "ratoon", cropping cycle which may have a shorter flooding season than the one listed in the table. It is recommended that the user apply the same growing season length for both the ratoon and primary cropping cycles.

Example The average number of acre-days harvested in a state from 1989-1991 is calculated as follows:

Average Area Harvested

$$[2,988,000 \text{ (acres in 1989)} + 3,146,000 \text{ (acres in 1990)} + 3,102,000 \text{ (acres in 1991)}] \div 3 \\ = 3,079,000 \text{ acres}$$

Low

$$\text{Average for 1990: } 3,079,000 \text{ acres} \times 60 \text{ days/yr} = 184,740,000 \text{ acre-days/yr}$$

High

$$\text{Average for 1990: } 3,079,000 \text{ acres} \times 153 \text{ days/yr} = 471,087,000 \text{ acre-days/yr}$$

- Multiply the average annual area harvested for the base year by the length of the growing season range to obtain the average number of acre-days harvested in the base year.

$$\begin{aligned} \text{Average Area Harvested (acres)} \times \text{Length of Growing Season (days/yr, low estimate)} \\ = \text{Acre-days per year (low estimate)} \end{aligned}$$

$$\begin{aligned} \text{Area Harvested (acres)} \times \text{Length of Growing Season (days/yr, high estimate)} \\ = \text{Acre-days per year (high estimate)} \end{aligned}$$

Step (3) Estimate Methane Emissions

- Multiply the number of acre-days harvested annually (both low and high) by the corresponding endpoints of the daily emissions rate range (0.1955 - 1.035 lbs CH₄/acre/day) to obtain the range of methane emissions from flooded rice fields.

$$\begin{aligned} \text{Average # of Acre-Days/yr (low)} \times 0.1955 \text{ lbs CH}_4/\text{acre-day} \\ = \text{CH}_4 \text{ Emissions (low)} (\text{lbs CH}_4/\text{yr}) \end{aligned}$$

$$\begin{aligned} \text{Average # of Acre-Days/yr (high)} \times 1.035 \text{ lbs CH}_4/\text{acre-day} \\ = \text{CH}_4 \text{ Emissions (high)} (\text{lbs CH}_4/\text{yr}) \end{aligned}$$

- Divide the results by 2000 to obtain methane emissions in tons CH₄.

Example Annual methane emissions from flooded rice fields for this state in 1990 is calculated as follows:

(a)	<u>Avg. Acre-Days</u>	<u>Emissions Coefficient</u>	<u>CH₄ Emissions</u>
low:	184,740,000 acre-days per year	x 0.1955 lbs CH ₄ /acre-day =	36,116,700 lbs CH ₄ /yr
high:	471,087,000 acre-days per year	x 1.035 lbs CH ₄ /acre-day =	487,575,000 lbs CH ₄ /yr
(b)			
low:	36,116,700 lbs CH ₄ /yr + 2000 lbs/ton	=	18,058 tons CH ₄ /yr
high:	487,575,000 lbs CH ₄ /yr + 2000 lbs/ton	=	243,788 tons CH ₄ /yr

WORKBOOK 9

EMISSIONS FROM AGRICULTURAL SOIL MANAGEMENT

Various agricultural soil management practices contribute to greenhouse gas emissions. The use of synthetic and organic fertilizers adds nitrogen to soils, thereby increasing natural emissions of nitrous oxide. Other agricultural soil management practices such as irrigation, tillage practices, or the fallowing of land can also affect trace gas fluxes to and from the soil since soils are both a source and a sink for carbon dioxide and carbon monoxide, a sink for methane, and a source of nitrous oxide. However, there is much uncertainty about the direction and magnitude of the effects of these other practices, so only the emissions from fertilizer use are included in the inventory at this time.

To estimate state emissions of N₂O from fertilizer use, four steps should be performed: 1) obtain the required data on fertilizer use; 2) calculate the three-year average for annual fertilizer consumption; 3) estimate nitrous oxide emissions in units of nitrogen; and 4) convert total emissions to units of N₂O. A worksheet is provided in Table 9-2 to assist in the calculations. A more detailed description of the method used to calculate N₂O emissions is provided in Discussion Section 9.

Step (1) Obtain Required Data (*Table 9-2, Columns A, B and C*)

- *Required Data.* The information needed to estimate N₂O emissions from fertilizer use is annual fertilizer consumption, by fertilizer type or total tons of nitrogen consumed in the state, for three consecutive years centered on the study year (e.g., to calculate 1990 N₂O emissions, data for 1989, 1990, and 1991 are needed). A list of various fertilizer types can be found in Table 9-1. Three years of data are recommended to avoid unusual annual variations due to economic, climatic, or other variables.
- *Data Sources.* Departments within each state responsible for conducting agricultural research and overseeing the agricultural sector should be consulted first. Additionally, state fertilizer consumption data can be found in *Fertilizer Summary Data* and *Commercial Fertilizers*, both published by the Tennessee Valley Authority.
- *Units for Reporting Data.* Fertilizer data should be reported in mass units of nitrogen (i.e., tons N). If fertilizer consumption is given in tons of material (as in the TVA *Fertilizer Summary Data*) rather than in tons N, the total mass may be converted to nitrogen content using the percentages in Table 9-1.

Step (2) Calculate Average Annual Nitrogen Consumption By Fertilizer Type (*Table 9-2, Column D*)

For each fertilizer type, calculate the three-year average annual consumption of nitrogen in the fertilizer.

Table 9-1. Nitrogen Content of Principal Fertilizers

MATERIAL	% NITROGEN
Nitrogen	
Ammonia, Anhydrous	82
Ammonia, Aqua	16-25
Ammonium nitrate	33.5
Ammonium nitrate-limestone mixtures	20.5
Ammonium sulfate	21
Ammonium sulfate-nitrate	26
Calcium cyanamide	21
Calcium nitrate	15
Nitrogen solutions	21-49
Sodium nitrate	16
Urea	.46
Urea-form	38
Phosphate	
Basic slag, Open hearth	-
Bone meal	2-4.5
Phosphoric acid	-
Rock phosphate	-
Superphosphate, Normal	-
Superphosphate, Concentrated	-
Superphosphoric acid	-
Potash	
Potassium chloride (muriate)	-
Potassium magnesium sulfate	-
Potassium sulfate	-
Multiple Nutrient	
Ammoniated superphosphate	3-6
Ammonium phosphate-nitrate	27
Ammonium phosphate-sulfate	13-16
Diammonium phosphate	16-21
Monoammonium phosphate	11
Nitric phosphates	14-22
Nitrate of soda-potash	15
Potassium nitrate	13
Wood ashes	-
Blast furnace slag	-
Dolomite	-
Gypsum	-
Kieserite (emjeo)	-
Limestone	-
Lime-sulfur solution	-
Magnesium sulfate (Epsom salt)	-
Sulfur	-
Note: A dash (-) indicates that the fertilizer contains either no nitrogen or a negligible amount of nitrogen.	

Example According to the TVA Fertilizer Summary Data, total U.S. consumption of ammonium nitrate in tons of material was: 1,898,650 in 1989; 1,777,545 in 1990; and 1,850,061 in 1991. To convert this to tons of nitrogen, multiply by the percent N content of ammonium nitrate (33.5%).

$$\begin{aligned} 1,898,650 \text{ tons of material} &\times 33.5\% = 636,115 \text{ tons N} \\ 1,777,545 \text{ tons of material} &\times 33.5\% = 595,478 \text{ tons N} \\ 1,850,061 \text{ tons of material} &\times 33.5\% = 619,770 \text{ tons N} \end{aligned}$$

Example The three-year average annual consumption for ammonium nitrate in the U.S. from 1987-1989 is calculated as follows:

$$(636,115 + 595,478 + 619,770) + 3 = 617,121 \text{ tons N}$$

Step (3) Estimate Nitrous Oxide Emissions (Table 9-2, Columns F)

- Multiply the three-year average for each fertilizer type by the appropriate emissions coefficient. The emission coefficient is taken from U.S. EPA (1994) and is based on research done by the U.S. Department of Agriculture (CAST, 1992). The recommended emission coefficient is 1.17 percent or 0.0117. The amount of fertilizer consumed (synthetic nitrogen, multiple-nutrient, and organic fertilizer, measured in mass units of nitrogen) is multiplied by this emission coefficient. The result will be N_2O emissions in units of N.

$$\text{Total } N_2O\text{-N Emissions (tons } N_2O\text{-N)} = \frac{\text{Total Nitrogen Content of Fertilizer (tons N)}}{\times 0.0117 \text{ (tons } N_2O\text{-N/ton N applied)}}$$

- Sum across all types of fertilizers to produce the total estimate for N_2O -N emissions from fertilizer use.

Example To estimate total N_2O -N emissions for the U.S. from ammonium nitrate,

<u>Nitrogen Content</u>	<u>Emissions Coefficient</u>	<u>N_2O Emissions (units of N)</u>
617,121 tons N	x 0.0117	= 7,220 tons N_2O -N

Step (4) Convert to Units of N_2O (Table 9-2, Column G)

- Multiply the emission estimates by 44/28 to convert them from units of N to units of N_2O .
- Sum across all fertilizer types to produce total N_2O emissions from fertilizer use in units of N_2O .

Example To convert N₂O-N emission estimates from ammonium nitrate [from step (3)] into units of N₂O,

$$7,220 \text{ tons N}_2\text{O-N} \times 44/28 = 11,346 \text{ tons N}_2\text{O}$$

Table 9-2. Worksheet to Calculate N₂O Emissions from Nitrogen Fertilizer Use

Fertilizer	<i>Input</i>	<i>Input</i>	<i>Input</i>	Average	<i>Input</i>	<i>D x E</i>	<i>E x 44/28</i>
	A	B	C	D	E	F	G
	Fertilizer Consumption (tons N)						
	1989	1990	1991	3-yr avg			
Ammonium Sulphate					0.0117		
Ammonium Nitrate					0.0117		
Sodium Nitrate					0.0117		
Urea					0.0117		
Ammonium Phosphate					0.0117		
Anhydrous Ammonia					0.0117		
Aqua Ammonia					0.0117		
Calcium Nitrate					0.0117		
Potassium Nitrate					0.0117		
Other					0.0117		
Total							

WORKBOOK 10

CARBON DIOXIDE EMISSIONS FROM FOREST MANAGEMENT AND LAND-USE CHANGE

This chapter provides methods for calculating greenhouse gas emissions from human activities that:

- affect the amount of biomass in existing biomass stocks on forests and other lands, without changing the way land is used (*e.g.*, management of standing forests, urban tree planting, logging), or
- change the way land is used (*e.g.*, clearing forests for agricultural use or suburban development, converting a grassland to cropland).

The dominant gas of concern in this source category is CO₂, and the methodology presented below, as well as in Discussion Section 10, is specific to CO₂. Other important greenhouse gases, including CH₄ and N₂O, and photochemically important gases, including CO, NO_x, and NMVOCs are also produced from forest management and land-use change activities. However, emissions of these gases that result from biomass burning (*i.e.*, wood consumption for energy production) are captured in Discussion Section 14, and emissions of these gases due to other activities (such as land flooding) are not yet explicitly included in the methodology. Instead, they are discussed as areas for further research in Discussion Section 10.

The fundamental basis for the methodology rests upon two linked themes: (1) the flux of CO₂ to or from the atmosphere is assumed to be equal to changes in the carbon stocks of existing biomass and soils, and (2) changes in the carbon stocks can be estimated by first establishing rates of change in land use and then applying simple assumptions about the biological response to the land use. The methodology is designed to be comprehensive, *i.e.*, cover all the main land-use change and forestry activities in the U.S., and to be feasible to implement by all states.

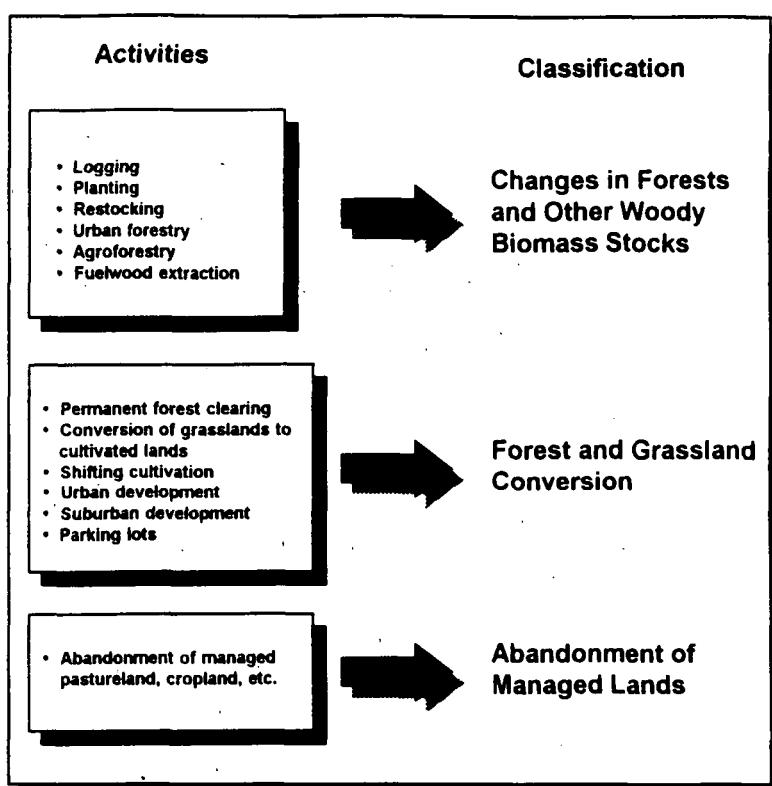
In estimating the effects of land use and land-use change on fluxes of greenhouse gases, it is reasonable to stage the calculation methods so that the most important components can be addressed first. Complexities and subtleties of the relationship of forestry and land-use change to fluxes of CO₂ and other gases can be incorporated in a consistent manner into subsequent calculations as knowledge advances and data improve. The methodology presented here focusses on a simple, practical, and fair procedure for determining the CO₂ flux directly attributable to forest management and land-use change activities. This procedure also accounts for the influence of past land-use changes on the contemporary CO₂ flux. It should be noted, however, that this method is based upon many simplifying assumptions in order to allow for implementation with only minimal data (these simplifying assumptions are discussed in detail in Discussion Section 10). At the same time, the methodology is sufficiently flexible to accommodate users with different levels of available data, *i.e.*, data with different levels of complexity and at different geographic scales. States are encouraged to apply the method in as detailed a manner as their data allow, as well as to estimate emissions from land use activities that are not explicitly included in the method if expertise and data are sufficient.

This section is divided into three parts, each of which reflects a general category of land-use

change and forest management activities. They are (see Figure 10-1 for a breakdown of the activities associated with each of the categories described below):

- **Changes in Forests and Other Woody Biomass Stocks:** The most important effects of human interactions with existing forests are considered in this single broad category, which includes commercial management and logging for forest products, replanting after logging or other forest timber removal, the harvest of fuelwood, and the establishment and operation of forest plantations as well as planting trees in urban, suburban, or other non-forest locations.
- **Forest and Grassland Conversion:** This category includes the conversion of forest and grasslands to pasture, croplands, or other managed uses as well as to shopping malls, parking lots, and suburban communities. These activities can significantly change the carbon stored in biomass and in soils.
- **Abandonment of Managed Lands:** Lands that had been managed previously (*i.e.*, croplands, pasture) and that are abandoned and allowed to regrow naturally, without any human interference, can re-accumulate significant amounts of carbon in their biomass and soils. This category includes these lands that are regrowing naturally into their prior grassland or forest conditions.

Figure 10-1. Land-Use Change and Forestry Activities Covered in Method



1. CO₂ FLUX FROM CHANGES IN FORESTS AND OTHER WOODY BIOMASS STOCKS (WORKSHEET 10-1)

In this part of the method, net emissions of CO₂ due to growth and harvest of woody biomass are estimated. First, the annual growth increment of biomass in plantations, managed forests, trees in farms, suburban areas and urban areas, and any other significant stocks of woody biomass are estimated. Next, annual harvests of biomass, *e.g.*, wood harvested for fuelwood, commercial timber and other uses, are estimated. It should be noted that emissions from soil carbon are not included in this section. This is because the effects of these activities on soil carbon are uncertain. Also, the methodology does not include time lags associated with decay of biomass harvests.

The net carbon emitted is equal to the total harvest of carbon minus the total growth

increment. If the figure is positive, then this counts as an emission of carbon, and if the figure is negative, it counts as a removal (or uptake). Finally, the net carbon emission/uptake is expressed as CO₂. These steps in the calculation are displayed in Worksheet 10-1.

Step (1) Obtain Required Data

Required Data. The data required to calculate CO₂ flux from changes in forests and other woody biomass stocks include:

Forests and Other Woody Biomass Areas: (1) managed forests and other woody biomass areas by type; (2) annual biomass growth rates of managed areas by type; and (3) biomass carbon fraction.

Tree Planting: (1) number of trees planted in afforestation and other tree planting activities by type; (2) annual biomass growth rates of planted trees; and (3) biomass carbon fraction.

Biomass Harvest: (1) annual commercial harvest; (2) biomass conversion/expansion factor¹; (3) fuelwood harvest; (4) other wood removals; (5) biomass carbon fraction; and (6) wood removed during forest clearing and burned as fuelwood.

Data Sources:

Forests and Other Woody Biomass Areas: The Forest Service of the U.S. Department of Agriculture (USFS) compiles forest resource data collected from periodic surveys in each state and Forest Service region, and publishes these data in tabular form. These tables include information on area, volume, removals, and timber product outputs, by state, ownership class, and species group. The most recent publications are for the years 1992 (Powell et al., 1993), 1987 (Waddell et al., 1989), and 1977 (USFS, 1982).

Tree Planting: There are no readily available published, national statistics on non-forest tree planting. It is recommended that states contact their State Forestry Department, particularly the urban forestry coordinator in this department, for this information.

Biomass Harvest: There are two approaches analysts can take to estimate wood removals:

- commercial harvest statistics; and
- fuelwood consumption estimates from Workbook Section 1.

For some states, commercial statistics will give only a partial account of wood removals and using both sources of statistics may provide the most accurate picture. Sources for

¹ Commercial harvest statistics are often provided in volumetric units and only account for the commercial portion of biomass. In this case, the harvested amounts must be adjusted in two ways to reflect the values needed for the emissions/uptake calculations. The volume of biomass must first be converted to mass of dry matter by applying a density. In addition, an expansion ratio must be applied to account for non-commercial biomass (limbs, small trees, etc.) harvested with the commercial biomass and left to decay or destroyed during processing.

commercial statistics include the USFS forest resource data publications, as discussed above, and Row and Phelps (1991).

Units for Reporting Data. Data should be reported in the following units:

- Forests and other woody biomass areas: 10^3 acres
- Number of trees planted: 10^3 trees
- Annual biomass growth rates of forests and woody biomass areas: tons dry matter per acre per year ($t \text{ dm}/\text{acre}/\text{yr}$)
- Annual biomass growth rates of planted trees: ton dry matter per tree per year ($t \text{ dm}/\text{tree}/\text{yr}$)
- Biomass carbon fraction: tons carbon per ton dry matter ($t \text{ C}/t \text{ dm}$)
- Annual commercial harvest: 10^3 cubic feet per year ($10^3 \text{ ft}^3/\text{yr}$)
- Biomass conversion/expansion factor: tons dry matter per cubic foot ($t \text{ dm}/\text{ft}^3$)
- Fuelwood harvest: 10^3 tons dry matter per year ($10^3 t \text{ dm}/\text{yr}$)
- Other wood removed: 10^3 tons dry matter per year ($10^3 t \text{ dm}/\text{yr}$)
- Wood removed during forest clearing and burned as fuelwood: 10^3 tons dry matter per year ($10^3 t \text{ dm}/\text{yr}$)

Step (2) Estimate Total Carbon Content in Annual Growth of Managed Forests and Other Woody Biomass Areas (Worksheet 10-1, Columns A - E)

- Obtain the number of acres (in thousands of acres) for each type of managed area on which biomass is accumulating, e.g., plantations, managed forest areas, etc. Enter this in Column A.
- For dispersed trees (e.g., urban tree planting, farm trees, etc.); enter the number of trees of each type (in 10^3 trees) in Column A.
- For each type of forest/woody biomass area, enter the Annual Growth Rate (in tons of dry matter per acre) in Column B. The default statistics in Table 10-1 or 10-6 can be used if state data are not available.
- For other non-forest trees, enter the Annual Growth Rate in tons of dry matter per tree per year in Column B, i.e., use the average annual growth rate per tree.
- For each type of forest/woody area, multiply the Area of Forest/Biomass Stocks by the Annual Growth Rate to give Annual Biomass Increment in thousand tons of dry matter. Enter the result in Column C.
- For non-forest trees, multiply the Number of Trees by the Annual Growth Rate to give Annual Biomass Increment in thousand tons of dry matter. Enter in Column C.
- For each type of biomass stock, enter the Carbon Fraction of Dry Matter in Column D. The default value is 0.5 for all biomass, if specific values are not available. (See Table 1-2 of Birdsey, 1992 (provided at the end of this chapter) for some species-specific values for the U.S.)
- Multiply the Annual Biomass Increment by the Carbon Fraction of Dry Matter to give the Total Carbon Uptake Increment (10^3 tons carbon). Enter the result in Column E.

Table 10-1
Average Annual Accumulation of Dry Matter as Biomass in Plantations

Forest Types		Average Annual Increment in Biomass (t dm/acre/yr)
Tropical	<i>Acacia</i> spp.	33.6
	<i>Eucalyptus</i> spp.	32.5
	<i>Tectona grandis</i>	17.9
	<i>Pinus</i> spp.	25.8
	<i>Pinus caribaea</i>	22.4
	Mixed Hardwoods	15.2
	Mixed Fast-Growing Hardwoods	20
	Mixed Softwoods	32.5
Temperate	Douglas Fir	13.5
	Loblolly Pine	9.0

Source: Derived from IPCC, 1994

- Add the figures in Column E and enter the total in the Total box at the bottom of the column.

Step (3) Estimate the Amount of Biomass Harvested (Worksheet 10-1, Columns F - L)

- Enter the annual amount of timber harvested in the state for commercial purposes and enter it in thousands of cubic feet in Column F.
- If necessary, enter the Biomass Conversion/Expansion Ratio in tons of dry matter per cubic foot (t dm/ft³) in Column G. The default conversion ratio (or biomass density) is 16 t dm/ft³ (see Table 1-2 of Birdsey, 1992 (provided at the end of this chapter) for some species-specific densities for the U.S.). In addition, an expansion factor should be applied if the timber harvest data do not account for all of the biomass that is destroyed during the harvest process, e.g., limbs, small trees, etc. The following default ratios can be used: 56 t dm/ft³ for undisturbed forests; 60.9 t dm/ft³ for logged forests; and 64.1 t dm/ft³ for unproductive forests (see Table 1-1 of Birdsey, 1992 (provided at the end of this chapter) for region- and forest type-specific expansion factors for the U.S.). If both conversion and expansion factors are needed, they can be combined by using ratios which are the product of the two: 28.19 t dm/ft³ for undisturbed forests; 30.4 t dm/ft³ for logged forests; and 32 t dm/ft³ for unproductive forests.
- Multiply the amount of Commercial Harvest by the Biomass Conversion/Expansion Ratio (if necessary) to give Total Biomass Removed in Commercial Harvest in thousand tons of dry matter. Enter the result in Column H.
- Enter Total Fuelwood Consumed annually (including wood for charcoal production) in thousand tons dry matter in Column I. (This accounting should have been done in Workbook and Discussion Sections 1).

- Enter the quantity of annual Total Other Wood Use in thousand tons dry matter in Column J.
- Add the Total Biomass Removed in Commercial Harvest (Column H) to the Total Fuelwood Consumed (Column I) to and Total Other Wood Used (Column J) to give Gross Biomass Consumption. Enter this result in Column K. Sum this column and enter the result in the Totals box at the foot of the column.
- Enter Wood Removed During Forest Clearing and Burned as Fuelwood in thousand tons dry matter (Worksheet 2, Column G) at the bottom of Column L.
- Subtract Wood Removed During Forest Clearing (Column L) from Gross Biomass Consumed (Column K) to give Net Biomass Consumption (Column M).

Step (4) Convert Wood Harvested to Carbon Removed (Worksheet 10-1, Columns M - O)

- Enter the Carbon Fraction of the biomass in Column N (the general default value for live biomass is 0.5 t C/t dm).
- Multiply Total Biomass Consumption (Column M) by Carbon Fraction (Column N) to give Annual Carbon Release (in 10^3 tons of carbon). Enter the result in Column O.

Step (5) Estimate Net Annual Amount of Carbon Uptake or Release (Worksheet 10-1, Columns O - Q)

- Subtract Annual Carbon Increment (Column O) from Total Carbon Released (Column E) to give Net Annual Carbon Uptake or Emissions. Enter the result in Column P.
- Multiply the Net Annual Carbon Uptake or Emissions (Column P) by 44/12 to give Annual CO₂ Emissions (if a positive value), or Uptake (if a negative value). Enter the result in Column Q.

**2. CO₂ EMISSIONS FROM FOREST AND GRASSLAND CONVERSION
(WORKSHEETS 10-2 THROUGH 10-4)**

Forest and grassland conversion to permanent cropland, pasture, or suburban and urban areas can result in the release of carbon not only from the clearing of land (*i.e.*, through decay of cleared biomass) but also due to the disturbance of the carbon stored in the soil. It should be noted that in some instances, some of the biomass cleared is burned as fuelwood. This burning results in emissions of CO₂ as well as CO, CH₄, NO_x, and N₂O. The non-CO₂ emissions from this source are assumed to be accounted for in the biofuels calculations presented in Discussion Section 14. This part of the method accounts for CO₂ emissions from cleared biomass that is burned and decays. As in the calculations for changes in forests and other woody biomass stocks, the methodology does not include time lags associated with biomass decay. Time lags associate with soil carbon emissions, however, are included.

Two sets of calculations are required to produce estimates of CO₂ emissions due to forest/grassland conversion:

- (1) Carbon released by decay or burning of net cleared aboveground biomass.
- (2) Carbon released from soil (delayed emissions, occurring over a 25-year period).

The totals are added together to arrive at total carbon released. Total carbon released is then converted to CO₂ emissions. As in the previous calculations, time lags associated with biomass decay are not included in the method. This simplifying assumption is discussed in Discussion Section 10.

Step (1) Obtain Required Data

Required Data: The following data are required to estimate emissions from forest and grassland conversion:

- Annual forest and/or grassland areas converted by type; in the inventory year and a 25-year average
- Aboveground biomass per area of forest and/or grassland by type
- Aboveground biomass per area of replacement vegetation
- Carbon in soil per unit forest and/or grassland area by type
- Fraction of carbon released from soil following forest and grassland conversion

Data Sources: The Soil Conservation Service of the U.S. Department of Agriculture (USDA/SCS) conducts an inventory of all non-Federal rural lands every five years, e.g., USDA/SCS (1989). This *National Resources Inventory* (NRI) contains land-use change data by state for croplands, pasturelands, rangelands, forest lands, and minor land uses. The latest NRI, for the year 1987, contains land-cover change matrices by state for the 1982 - 1987 period. These matrices not only provide the total change in each land-use over the period, but also the dynamics of each change (e.g., of the total 1982 - 1987 conversion of cropland, how much was to pastureland and how much was to forest land). However, the NRI data only covers non-federal rural lands, so a large portion of the U.S. forest lands are not included in this data base. The forest area data in the USFS forest resource publications discussed in the previous section of this chapter, however, include net changes in forest areas. Therefore, if these USFS data are used in the previous section, one has already accounted for conversion of forest lands to other lands.

Units for Reporting Data: Data should be collected in the following units:

- Annual area of forest and grassland converted in the inventory year and averaged over 25 years: 10³ acres per year
- Aboveground biomass: tons dry matter per acre (t dm/acre)
- Carbon in soil: tons carbon per acre (t C/acre)

Step (2) Estimate CO₂ Released by Decay of Net Cleared Biomass (Worksheet 10-2, Columns A - I)

- Enter the figures for Annual Area Converted (in inventory year) in thousand acres per year for each forest/grassland type in Column A.
- Enter the Aboveground Biomass Density in tons of dry matter per acre (t dm/acre) before conversion in Column B. Default values are provided in Tables 10-2 and 10-3.

Table 10-2
Aboveground Dry Matter in Tropical Forests
(t dm/acre)

Moist Forest		Seasonal Forest		Dry Forest	
Primary	Secondary	Primary	Secondary	Primary	Secondary
515.6	425.9	313.8	269	134.5	56

Source: Derived from IPCC, 1994

Table 10-3
Aboveground Dry Matter in Temperate and Boreal Forests
(t dm/acre)

	Temperate Forests		Boreal Forests
	Evergreen	Deciduous	
Primary	661.3	560.4	369.8
Secondary	493.2	392.3	269

Source: Derived from IPCC, 1994

- Enter the Aboveground Biomass Density in tons of dry matter per acre (t dm/acre) after conversion in Column C. This figure includes any biomass not fully cleared (default value = 0) and the biomass regrowth in agricultural use (the default value is 22.4 tons dry matter per acre) or other use subsequent to clearing.
- Subtract the value in Column C from the value in Column B to produce Net Change in Biomass Density in tons of dry matter per acre. Enter the results in Column D.
- Multiply the Annual Area Converted (Column A) by the Net Change in Biomass Density (Column D) to calculate the Annual Loss of Biomass (aboveground) for each forest/grassland type in thousand tons of dry matter. Enter the results in Column E.
- Enter the Fraction of Biomass Used as Fuelwood in Column F.
- Multiply Fraction of Biomass Used as Fuelwood (Column F) by the Average Annual Loss of Biomass (Column E) to determine Amount of Annual Loss of Biomass Used as Fuelwood in thousand tons dry matter. Enter this result in Column G. (This figure is used in Step (3) of the calculations for changes in forests and woody biomass stocks).
- Enter the Carbon Fraction in Aboveground Biomass in Column H (default fraction 0.5 t C/t dm).
- Multiply the Annual Loss of Biomass (Column E) by the Carbon Fraction (Column H) to

calculate Carbon Released from Loss of Aboveground Biomass. Enter the figures in Column I.

- Add the figures in Column I and enter the total in the Subtotal box at the bottom of the column.

Step (3) Estimate Carbon Released by Soil (Worksheet 10-3, Columns A - E)

- Enter the Average Annual Forest/Grassland Converted over the last 25 years in thousand acres per year in Column A.
- Enter the Soil Carbon Content Before Conversion by forest or grassland type in Column B. See Table 10-4 for forest soil defaults. Defaults for grasslands are 134.5 tons/acre for tropical zones and 156.9 tons/acre for temperate zones.

Table 10-4
Carbon in Forest Soils
(tons C/acre)

Forest Type			
Tropical	Moist	Seasonal	Dry
	257.8	224.2	134.5
Temperate	Evergreen	Deciduous	
Primary	300.4	300.4	
Secondary	269.0	269.0	
Boreal			
Primary	461.8		
Secondary	414.7		

Source: Derived from IPCC, 1994

Note: See Table 1-3 of Birdsey (1992) for region-specific values of forest soil carbon in the U.S.

- Multiply the Average Annual Forest/Grassland Converted (Column A) by the Carbon Content of Soil Before Conversion (Column B) to calculate the Total Annual Potential Soil Carbon Loss in thousand tons carbon per year. Enter the result in Column C.
- Enter the Fraction of Carbon Released over 25 years in Column D (default fraction 0.5).
- Multiply the Total Annual Potential Soil Carbon Losses by the Fraction of Carbon Released to give Carbon Release from Soil in thousand tons carbon per year. Enter the result in Column E.
- Add the totals for each forest/grassland type and enter the total in the Subtotal box at the bottom of the column.

Step (4) Estimate Total CO₂ Emissions from Forest and Grassland Conversion (Worksheet 10-4, Columns A - D)

- Enter the Emissions from Biomass Loss (contained in the Subtotal box of Column I in Worksheet 10-2) in Column A.
- Enter Long-Term Emissions from Soil Carbon (contained in the Subtotal box of Column E in Worksheet 10-3) in Column B.
- Add the Figures in Columns A and B to Calculate Total Annual Carbon Release (in the inventory year from clearing over a 25 year period). Enter the result in Column C.
- Multiply the Total Annual Carbon Release by 44/12 to convert it into the Total Annual CO₂ Release. Enter the result in Column D.

**3. ABANDONMENT OF MANAGED LANDS
(WORKSHEET 10-5)**

This section deals with emissions/uptake from the abandonment of managed lands. Managed lands include:

- cultivated lands, and
- pasture (*e.g.*, lands used for grazing animals).

Carbon accumulation on abandoned lands is sensitive to the type of natural ecosystem (forest type or grasslands) which is regrowing. Therefore, data on abandoned lands regrowing should be obtained by type. For lands that are growing into grasslands, the default assumption is that net accumulation of aboveground biomass is zero. Only soil carbon is calculated in that case. Also, because regrowth rates usually decline after a time, the periods considered are land abandoned during the 20 years prior to the inventory year (*i.e.*, between 1970 and 1990); and land abandoned between 20 and 100 years prior to the inventory year (*i.e.*, between 1890 and 1970).

When managed lands are abandoned, carbon may or may not re-accumulate on the land. Abandoned areas therefore are split into those which re-accumulate carbon and those which do not regrow or which continue to degrade. Only natural lands that are regrowing are explicitly included in the calculations since lands that do not regrow do not accumulate carbon and abandoned lands that degrade are not believed to be a significant source of emissions. However, if users of the method believe that degrading lands contribute significantly to emissions, and data are available with which to estimate emissions, degrading lands can be included in the calculations.

Four sets of calculations are used to produce estimates of CO₂ uptake from biomass regrowth and soils. They relate to the quantity of land abandoned and the length of time for which it has been abandoned:

- Annual carbon uptake in aboveground biomass on land abandoned in the last twenty years.
- Annual carbon uptake in soils on land abandoned in the last twenty years.

- Annual carbon uptake in aboveground biomass on land abandoned between twenty and a hundred years before inventory year (optional step, only complete if data are readily available).
- Annual carbon uptake in soils on land abandoned between twenty and a hundred years before inventory year (optional step, only complete if data are readily available).

These are then totaled and the carbon uptake is converted into CO₂ removal.

Step (1) Obtain Required Data

Required Data. To calculate uptake from abandoned lands, the following data are necessary:

For Years Between 1970 and 1990: (1) total area abandoned during last 20 years that is regenerating; (2) annual average biomass accumulation per unit area regenerating; (3) average annual soil C accumulation per unit area regenerating; and (4) the carbon fraction of replacement biomass.

For Years Between 1890 and 1970 (optional): (1) total area abandoned between 20 and 100 years that is regenerating; (2) average annual biomass accumulation per unit area regenerating; (3) average annual soil C accumulation per unit area regenerating; and (4) the carbon fraction of replacement biomass.

Data Source. There are no readily available national statistics with which to estimate fluxes from this source, although the NRI data that were discussed in the previous section may be useful. States could contact their SCS State offices to obtain detailed state-level information.

Units for Reporting Data. Data should be reported in the following units:

For Years Between 1970 and 1990:

- Total area abandoned during last 20 years that is regenerating in thousand acres;
- Annual average biomass accumulation per unit area regenerating in tons of dry matter per acre per year (t dm/acre/yr);
- Average annual soil C accumulation per unit area regenerating in tons of carbon per acre per year (t C/acre/yr);
- Carbon fraction of replacement biomass in tons of carbon per ton of dry matter (t C/t dm).

For Years Between 1890 and 1970 (optional):

- Total area abandoned between 20 and 100 years that is regenerating in thousand acres;
- Average annual biomass accumulation per unit area regenerating in tons of dry matter per acre per year (t dm/acre/yr);
- Average annual soil C accumulation per unit area regenerating in tons of carbon per acre per year (t C/acre/yr); and
- Carbon fraction of replacement biomass in tons of carbon per ton of dry matter (t C/t dm).

Step (2) Calculate Annual Carbon Uptake in Aboveground Biomass (Land Abandoned in the Last Twenty Years) (Worksheet 10-5, Columns A - E)

- Enter the Total Area Abandoned during the last twenty years that is regrowing (in 10^3 acres) in Column A.
- Enter the Annual Rate of Aboveground Biomass Growth (in tons dry matter per acre per year) in Column B. See Table 10-5 for defaults.

Table 10-5
Average Annual Biomass Uptake by Natural Regeneration
(t dm/acre)

Region	Forest Types					
	Moist Forests		Seasonal Forests		Dry Forests	
	0-20 yrs	20-100 yrs	0-20 yrs	20-100 yrs	0-20 yrs	20-100 yrs
Tropical	17.9	2.0	11.2	1.1	9.0	0.56
<p>Note: Growth rates are derived by assuming that tropical forests regrow to 70 percent of undisturbed forest biomass in the first twenty years. All forests are assumed to regrow to 100 percent of undisturbed forest biomass in 100 years. Assumptions on the rates of growth in different time periods are derived from Brown and Lugo, 1990.</p>						
Temperate	0-20 yrs		20-100 yrs			
	Evergreen	6.7	6.7			
	Deciduous	4.5	4.5			
Boreal	2.24		2.24			
<p>Source: Derived from IPCC, 1994 Note: Temperate and boreal forests actually require considerably longer than 100 years to reach the biomass density of a fully mature system. Harmon et al. (1990), for example, report carefully designed simulations indicating that a 100-year old stand of douglas fir would contain only a little over half the biomass of a 450-year old growth stand of the same species. There is also evidence that growth rates in temperate and boreal systems are more nearly linear over different age periods than is the case for tropical systems. Nabuurs and Mohren (1993) suggest that growth rates for several different species in temperate and boreal zones rise slowly and peak at ages of 30 - 55 years and decline slowly thereafter. This suggests that using the same default values for 0-20 years and 20-100 years may be a reasonable first approximation. Nabuurs and Mohren (1990) also illustrate that growth rates may vary as much as a factor of ten for stands of the same species and age, depending on site-specific conditions.</p>						

- Multiply the Total Area Abandoned and Regrowing (Column A) by the Annual Rate of Aboveground Biomass Growth (Column B) to give the Annual Aboveground Biomass Growth (in 10^3 tons dry matter). Enter the result in Column C.
- Enter the Carbon Fraction of Aboveground Biomass in Column D (Default is 0.5 t C/t dm)
- Multiply Annual Aboveground Biomass Growth (Column C) by the Carbon Fraction of Aboveground Biomass (Column D) to give the Annual Carbon Uptake in Aboveground Biomass. Enter the result in Column E.

- Add the figures in Column E and enter the total in the Subtotal box at the bottom of the column.

Step (3) Calculate Annual Carbon Uptake in Soils (Land Abandoned in Last Twenty Years) (Worksheet 10-6, Columns F - G)

- Enter Annual Rate of Uptake of Carbon in Soils (in tons of carbon per acre per year) in Column F. Default values for soil carbon in temperate and boreal forests are provided in Table 10-6. No values are available for tropical systems or grasslands.

Table 10-6
Annual Soil Carbon Accumulation in Temperate and Boreal Forests
(tons C/acre yr)

Temperate		Boreal
Evergreen	Deciduous	
2.9	2.9	4.5

Source: Derived from IPCC (1994).

- Multiply the Total Area Abandoned and Regrowing (Column A) by the Annual rate of Uptake of Carbon in Soils (Column F) to give the Total Annual Carbon Uptake in Soils (in 10^3 tons carbon per year). Enter the results in Column G.
- Add the figures in Column G and enter the total in the Subtotal box at the bottom of the column.

Step (4) Calculate Annual Carbon Uptake in Aboveground Biomass (Land Abandoned Between Twenty and a Hundred Years) (Worksheet 10-6, Columns H - L) (Optional)

- Enter the Total Area Abandoned for twenty to a hundred years (in 10^3 acres) in Column H.
- Enter the Annual Rate of Aboveground Biomass Growth (in tons of dry matter per acre per year) in Column I. See Table 10-6 for default values.
- Multiply the Total Area Abandoned (Column H) by the Annual Rate of Aboveground Biomass Growth (Column I) to give the Annual Aboveground Biomass Growth (in 10^3 tons dry matter per year). Enter the result in Column J.
- Enter the Carbon Fraction of Aboveground Biomass in Column K (default fraction 0.5 t C/t dm).
- Multiply the Annual Aboveground Biomass Growth (Column J) by the Carbon Fraction of Aboveground Biomass (Column K) to give the Annual Carbon Uptake in Aboveground Biomass. Enter the result in Column L.

- Add the figures in Column L and enter the total in the Subtotal box at the bottom of the column.

**Step (5) Calculate Annual Carbon Uptake in Soils (Land Abandoned between Twenty and a Hundred Years) (Worksheet 10-7, Columns M and N)
(Optional)**

- Enter the Annual Rate of Uptake of Carbon in Soils (in tons of carbon per acre per year) in Column M. Default values are 0.5 times the values in Table 10-6.
- Multiply the Total Area Abandoned (Column H) by the Annual Rate of Uptake of Carbon in Soils (Column M) to give the Total Annual Carbon Uptake in Soils (in 10^3 tons carbon per year). Enter the results in Column N.
- Add the figures in Column N and enter the total in the Subtotal box at the bottom of the column.

Step (6) Calculate Total CO₂ Uptake from Abandoned Lands (Worksheet 10-7, Columns E, G, L, N, O and P)

- Add the subtotals from Columns A, G, L and N and enter the Total Carbon Uptake from Abandoned Lands in Column O.
- Multiply the Total Carbon Uptake by 44/12 to give Total CO₂ Uptake from the abandonment of managed lands. Enter the result in Column P. For consistency with other emission/uptake categories, it is necessary to reverse the sign of these results, so that CO₂ uptake by abandoned lands is expressed as a negative value.

**4. CO₂ EMISSIONS/UPTAKE FROM ALL FOREST MANAGEMENT AND LAND-USE ACTIVITIES
(WORKSHEET 10-6)**

- Enter net CO₂ emissions/uptake from changes in forests and woody biomass stocks (figure from Worksheet 10-1, Column Q) in Column A (in 10^3 tons CO₂/yr).
- Enter net CO₂ emissions from forest and grassland conversion (figure from Worksheet 10-4, Column D) in Column B (in 10^3 tons CO₂/yr).
- Enter net CO₂ emissions/uptake from abandoned lands (figure from Worksheet 10-5, Column P) in Column C (in 10^3 tons CO₂/yr).
- Sum Columns A, B, and C to obtain net CO₂ Emissions/Uptake from all forest management and land-use activities in a state. Enter the result in Column D (in 10^3 tons CO₂/yr). If the figure is positive, then this source category is counted as a net emission of CO₂. If the figure is negative, then this source category is counted as a net uptake of CO₂ and can be subtracted from the total amount of CO₂ emitted in a state.

Worksheet 10-1: Changes in Forests and Woody Biomass Stock

Type	<i>Column A</i> Area of Biomass/Forest Stocks (10^3 acres)	<i>Column B</i> Annual Growth Rate (t dm/acre/yr)	<i>(A x B)</i> <i>Column C</i> Annual Biomass Increment (10^3 t dm/yr)	<i>Column D</i> Carbon Fraction of Dry Matter (t C/t dm)	<i>(C x D)</i> <i>Column E</i> Total Carbon Uptake Increment (10^3 t C/yr)
	<i>Column A</i> Number of Trees (10^3 s of trees)	<i>Column B</i> Annual Growth Rate (t dm/tree/yr)	Follow the Column Headings Above		
					Total:

Worksheet 10-1: Changes in Forests and Woody Biomass Stocks (Continued)

Harvest Categories	Column F Amount of Commercial Timber Harvested (10^3 ft 3 /yr)	Column G Biomass Conversion/ Expansion Ratio (t dm/ft 3)	(F x G) Column H Total Biomass Removed in Commercial Harvest (10^3 t dm/yr)	(Column G, Worksheet 10-2) Column I Fuelwood Consumed (10^3 t dm/yr)	Column J Total Other Wood Used (10^3 t dm/yr)	(H + I + J) Column K Gross Biomass Consumed (10^3 t dm/yr)	Column L Wood Removed from Forest Clearing (10^3 t dm/yr)	(K - L) Column M Net Biomass Consumption (10^3 t dm/yr)
Totals:								

Worksheet 10-1: Changes in Forests and Woody Biomass Stocks (Continued)

<i>Column N</i> Carbon Fraction of Dry Matter (t C/t dm)	<i>(M x N)</i> <i>Column O</i> Annual Carbon Released (10^3 t C/yr)	<i>(O - E)</i> <i>Column P</i> Net Annual Carbon Uptake or Release (10^3 t C/yr)	<i>(P x 44/12)</i> <i>Column Q</i> Annual CO ₂ Emissions or Uptake (10^3 t CO ₂ /yr)

Worksheet 10-2: Forest and Grassland Conversion

Land Types		Column A Annual Area Converted (10^3 acres/yr)	Column B Above-ground Biomass Density Before Conversion (t dm/acre)	Column C Above-ground Biomass Density After Conversion (t dm/acre)	(B - C) Net Change in Biomass Density	(A x D) Annual Loss of Above-ground Biomass (t dm/yr)	Column E Fraction of Biomass Used as Fuelwood	(E x F) Column G Amount of Annual Loss of Biomass Used as Fuelwood (10^3 t dm/yr)	Column H Carbon Fraction in Above-ground Biomass ($t\text{C}/t\text{dm}$)	(E x H) Column I Carbon Released from Loss of Above-ground Biomass (10^3 t C/yr)
Tropical	Moist Forest	Primary								
		Secondary								
	Seasonal Forests	Primary								
		Secondary								
	Dry Forests	Primary								
		Degraded								
Temperate	Evergreen	Primary								
		Secondary								
	Deciduous	Primary								
		Secondary								
Boreal	Primary									
	Secondary									
Grassland										
Other										
								Subtotal:		

Worksheet 10-3: Forest and Grassland Conversion

Land Types			<i>Column A</i> Average Annual Forest/Grassland Converted (25-year average) (10^3 acres/yr)	<i>Column B</i> Carbon Content of Soil Before Conversion (t C/acre)	<i>(A x B)</i> <i>Column C</i> Total Annual Potential Soil Carbon Losses (10^3 t C/yr)	<i>Column D</i> Fraction of Carbon Released over 25 Years	<i>(C x D)</i> <i>Column E</i> Carbon Released from Soil (10^3 t C/yr)
			Primary	Secondary	Primary	Secondary	Primary
Tropical	Moist Forest	Primary					
		Secondary					
	Seasonal Forests	Primary					
		Secondary					
	Dry Forests	Primary					
		Degraded					
Temperate	Evergreen	Primary					
		Secondary					
	Deciduous	Primary					
		Secondary					
Boreal	Primary						
	Secondary						
Grassland							
Other							
						Subtotal:	

Worksheet 10-4: Forest and Grassland Conversion

<i>Column A</i> Emissions from Biomass Loss (10^3 t C/yr) (10-year average)	<i>Column B</i> Long-Term Emissions from Soil (10^3 t C/yr) (25-year average)	<i>Column C</i> $(A + B)$ Total Annual Carbon Release (10^3 t C/yr)	<i>Column D</i> $(C \times 44/12)$ Total Annual CO ₂ Release (10^3 t CO ₂ /yr)

Worksheet 10-5: Abandoned Lands

Regrowth of Land Type	Column A	Column B	(A x B)	Column D	(C x D)
	20 Year Total Area Abandoned and Regrowing (10^3 acres)	Annual Rate of Aboveground Biomass Growth (t dm/acre/yr)	Column C	Annual Aboveground Biomass Growth (10^3 t dm)	Column E
Tropical Forests	Moist				
	Seasonal				
	Dry				
Temperate Forests	Evergreen				
	Deciduous				
Boreal Forests					
Grasslands					
Other					
				Subtotal:	

Worksheet 10-5: Abandoned Lands (Continued)

Regrowth of Land Type	<i>Column F</i> Annual Uptake of Carbon in Soils (t C/acre/yr)	<i>(A x F)</i> <i>Column G</i> Total Annual Carbon Uptake in Soils, \leq 20 yrs (10^3 t C/acre/yr)	<i>(Optional)</i> <i>Column H</i> Total Area Abandoned, 20 - 100 yrs (10^3 acres)	<i>(Optional)</i> <i>Column I</i> Annual Rate of Aboveground Biomass Growth (t dm/acre/yr)	<i>(Optional)</i> <i>(H x I)</i> <i>Column J</i> Aboveground Biomass Growth (10^3 t dm/yr)	<i>(Optional)</i> <i>Column K</i> Carbon Fraction of Aboveground Biomass (t C/t dm)	<i>(Optional)</i> <i>(J x K)</i> <i>Column L</i> Annual Carbon Uptake in Aboveground Biomass, 20 - 100 yrs (10^3 t C/yr)

Tropical Forests	Moist						
	Seasonal						
	Dry						
Temperate Forests	Evergreen						
	Deciduous						
Boreal Forests							
Grasslands							
Other							
		Subtotal:					Subtotal:

Worksheet 10-5: Abandoned Lands (Continued)

Regrowth of Land Type	(Optional) <i>Column M</i> Annual Rate of Carbon Uptake (t C/acres/yr)	(Optional) <i>Column N</i> Total Annual Carbon Uptake in Soils, 20 - 100 yrs (10^3 t C/acre/yr)	(Optional) <i>Column O</i> $(E + G + L + N)$ Total Carbon Uptake from Abandoned Lands (10^3 t C/yr)		(Optional) <i>Column P</i> Total Carbon Dioxide Uptake (10^3 t CO ₂ /yr)

Tropical Forests	Moist				
	Seasonal				
	Dry				
Temperate Forests	Evergreen				
	Deciduous				
Boreal Forests					
Grasslands					
Other					
		Subtotal:			

Worksheet 10-6: Total CO₂ Emissions/Uptake from Forest Management and Land-Use Activities

<i>(Column Q, Worksheet 10-1)</i> <i>Column A</i>	<i>(Column D, Worksheet 10-4)</i> <i>Column B</i>	<i>(Column P, Worksheet 10-5)</i> <i>Column C</i>	<i>(A + B + C)</i> <i>Column D</i>
Net CO ₂ Emissions/Uptake from Changes in Forests and Woody Biomass Stocks (10 ³ t CO ₂ /yr)	Net CO ₂ Emissions from Forest and Grassland Conversion (10 ³ t CO ₂ /yr)	Net CO ₂ Emissions/Uptake from Abandoned Lands (10 ³ t CO ₂ /yr)	Net CO ₂ Emissions/Uptake from All Forest Management and Land-Use Activities (10 ³ t CO ₂ /yr)

TABLES FROM BIRDSEY (1992)

Table 1.1—Ratio of total volume¹ to merchantable volume²

Region	Above-ground ratio ³		Below-ground proportion ⁴		Ratio ⁵	
	Softwood	Hardwood	Softwood	Hardwood	Softwood	Hardwood
Southeast	1.408	1.793	.163	.197	1.682	2.233
South Central	1.495	2.304	.163	.1971	.7862	.869
Northeast	1.820	1.808	.170	.155	2.193	2.140
Mid Atlantic	1.820	1.808	.170	.155	2.193	2.140
North Central	2.087	2.043	.170	.155	2.514	2.418
Central	2.159	2.240	.170	.155	2.601	2.651
Rocky Mountain	1.898	1.871	.158	.155	2.254	2.214
Pacific Coast	1.410	1.926	.158	.155	1.675	2.279

¹ Volume of all above- and below-ground tree biomass for all live and dead trees, including main stem, branches and twigs, foliage, bark, roots, and root bark.

² The gross volume of the central stem from a 1-foot stump to a minimum 4.0 inch top diameter outside bark, or to the point where the central stem breaks into limbs; less deductions for rot, roughness, or poor form; for live trees of commercial species at least 5.0 inches d.b.h., and meeting specified standards of quality.

³ The ratio of total above-ground tree biomass to merchantable tree biomass from Cost and others (1990) and other Forest Service reports.

⁴ The proportion of total above- and below-ground biomass below the ground (Koch 1989).

⁵ The ratio of total volume to merchantable volume = data column 1 or 2 adjusted for the below-ground proportion (e.g., col. 5 = col. 1 + [1 - col. 3]).

Table 1.2—Factors to convert tree volume (cubic feet) to carbon (pounds)

Region	Forest type	Specific gravity ¹		Percent carbon ²		Factor ³	
		Softwood	Hardwood	Softwood	Hardwood	Softwood	Hardwood
Southeast and	Pines	.510	.639	.531	.497	16.90	19.82
South Central	Oak-hickory	.536	.639	.531	.479	17.76	19.82
	Oak-pine	.523	.639	.531	.497	17.33	19.82
	Bottomland hardwoods	.460	.580	.531	.497	15.24	17.99
Northeast and	Pines	.378	.543	.521	.498	12.29	16.87
Mid-Atlantic	Spruce-fir	.369	.525	.521	.498	12.00	16.31
	Oak-hickory	.374	.636	.521	.498	12.16	19.76
	Maple-beech-birch	.384	.600	.521	.498	12.48	18.65
	Bottomland hardwoods	.460	.580	.521	.498	14.96	17.99
	Pines	.421	.530	.521	.498	13.69	16.47
North Central and Central	Spruce-fir	.351	.480	.521	.498	11.41	14.92
	Oak-hickory	.416	.632	.521	.498	13.52	19.64
	Maple-beech	.372	.576	.521	.498	12.09	17.90
	Aspen-birch	.370	.465	.521	.498	12.03	14.45
	Bottomland hardwoods	.460	.580	.521	.498	14.96	17.99
Rocky Mountain and	Douglas-fir	.473	.380	.512	.496	15.11	11.76
Pacific Coast	Ponderosa pine	.416	.380	.512	.496	13.29	11.76
	Fir-spruce	.349	.380	.512	.496	9.80	10.67
	Hemlock-Sitka sp.	.434	.433	.512	.496	12.17	12.16
	Lodgepole pine	.423	.380	.512	.496	11.86	10.67
	Larch	.508	.433	.512	.496	14.26	12.16
	Redwoods	.416	.580	.512	.496	11.68	16.29
	Hardwoods	.424	.384	.512	.496	11.90	10.77

¹ Weighted average specific gravity of the three most common (in terms of volume) softwood or hardwood species within the forest type.

² From Koch (1989).

³ Factor = specific gravity times the weight of a cubic foot of water (62.4 lbs) times percent carbon.

Table 1.3. *Estimates of organic soil carbon in relatively undisturbed secondary forests in the United States, by region*¹

Region	Soil carbon	
	(Kg/m ²)	(Lbs/ac)
Southeast	7.74	69,044
South Central	7.58	67,626
Northeast	16.21	144,703
Mid-Atlantic	11.56	103,173
North Central	13.09	116,791
Central	8.33	74,302
Rocky Mountain	8.02	71,571
Pacific Coast	9.77	87,191

¹ Data from Post and others (1982).

Table 1.4—*Estimates of organic matter and carbon on the forest floor¹ by region and forest type*

Region	Forest type	Organic matter ²	
		(Kg/ha)	(Lbs/ac)
Southeast	Pines	20,026	10,361
	Oak-pine	15,132	7,829
	Oak-hickory	10,237	5,296
	Bottomland hardwood	11,480	5,939
South Central	Pine	20,026	10,361
	Oak-pine	16,375	8,472
	Oak-hickory	12,723	6,582
	Bottomland hardwood	11,480	5,939
Northeast and Mid-Atlantic	Pines	44,574	23,061
	Spruce-fir	44,693	23,122
	Hardwoods	32,207	16,663
	Pines	44,574	23,061
North Central and Central	Spruce-fir	44,693	23,122
	Oak-hickory and bottomland hardwoods	23,282	12,045
	Maple-beech and	32,207	16,663
	Aspen-birch		
Rocky Mountain and Pacific Coast	Douglas-fir, Redwoods, Larch, Ponderosa pine	44,574	23,061
	Fir-spruce	88,520	45,797
	Lodgepole pine	25,922	13,411
	Hemlock-Sitka spruce	27,490	14,222
	Hardwoods	32,207	16,663

¹ All dead organic matter above the mineral soil horizons, including litter, humus, and other woody debris (excludes standing dead trees).

² Most entries from Vogt and others (1986), based on summaries of ecological studies grouped by broad forest ecosystem (e.g., warm temperate deciduous).

³ Carbon (lbs/ac) = organic matter (kg/ha) x .58 (percent carbon) x .892.

WORKBOOK 11

GREENHOUSE GAS EMISSIONS FROM BURNING OF AGRICULTURAL CROP WASTES

In some parts of the U.S., agricultural crop wastes are burned in the field to clear remaining straw and stubble after harvest and to prepare the field for the next cropping cycle. When crop residues are burned, a number of greenhouse gases are released, including carbon dioxide, methane, carbon monoxide, nitrous oxide, and oxides of nitrogen. However, crop residue burning is not thought to be a net source of carbon dioxide because the carbon dioxide released during burning is reabsorbed by crop regrowth during the next growing season. It is, however, thought to be a net source of these other gases.

To estimate emissions of CH_4 , N_2O , CO, and NO_x from burning of agricultural wastes, the following general steps are necessary: 1) obtain the required data for crops whose waste is commonly burned; 2) estimate the total amount of carbon burned; and 3) calculate emissions based on the amount of CO_2 released and on a range of emission ratios. These steps are outlined in detail below. A more detailed description of the methodology is provided in the discussion section on agricultural crop wastes. Greenhouse gas emissions from burning crop residues for energy production should be estimated as part of biomass material used as energy; this issue is addressed in the CO_2 from energy discussion section.

Step (1) Obtain Required Data

- *Required Data.* The information needed to estimate greenhouse gas emissions from burning of agricultural wastes is the annual production of crops with residues that are commonly burned over three consecutive years (e.g., to calculate 1990 emissions, data from 1989, 1990, and 1991 are needed).
- *Data Source.* State agencies responsible for overseeing the agricultural sector should be consulted first. Additionally, annual crop production data can be found in the USDA's *Crop Production* or in the U.S. Department of Commerce's *Census of Agriculture*.
- *Units for Reporting Data.* Annual crop production should be reported in pounds. If production data are reported in hundred weight (CWT), multiply by 100 to convert to pounds. If data are reported in bushels, the conversion factors provided in Table 11-1 may be used to convert to pounds.

Table 11-1. Conversion Factors for Selected Crops

Crop	Conversion Factor (lbs/bu)	Crop	Conversion Factor (lbs/bu)
Wheat	60	Pea	60
Barley	48	Bean	60
Corn	56	Soybeans	60
Oats	32	Potatoes	60
Rye	56	Feedbeet	50
Rice	45	Sugarbeet	50
Millet	48-60	Artichoke	50
Sorghum	60	Peanut	17-25

Example

According to the USDA's *Crop Production 1990 Summary* and *Crop Production 1992 Summary*, total U.S. wheat production in 1989, 1990, and 1991 was **2,036,618,000 bushels**, **2,736,428,000 bushels**, and **1,981,139,000 bushels**, respectively.

$$1989: \quad 2,036,618,000 \text{ bu} \times 60 \text{ lbs/bu} = 122,197,080,000 \text{ pounds}$$

$$1990: \quad 2,736,428,000 \text{ bu} \times 60 \text{ lbs/bu} = 164,185,680,000 \text{ pounds}$$

$$1991: \quad 1,981,139,000 \text{ bu} \times 60 \text{ lbs/bu} = 118,868,340,000 \text{ pounds}$$

3-yr average

$$[122,197,080,000 \text{ lbs} + 164,185,680,000 \text{ lbs} + 118,868,340,000 \text{ lbs}] \div 3 = \\ 135,083,700,000 \text{ lbs}$$

Step (2) Calculate the Amount of Dry Matter Burned (Table 11-2, Columns A-F)

- For each crop, calculate the amount of dry matter burned. Table 11-2 is provided to assist the user with this step. In column A, enter the amount of crop produced (in pounds, by crop type). Using the default data provided in Table 11-2, multiply columns A-E to obtain pounds of dry matter burned.

Amount of Dry Matter Burned (lbs) = Amount of Crop Produced (lbs) x Residue/Crop Ratio x Fraction of Residue Burned *in situ* (%) x Dry Matter Content of the Residue (%) x Fraction Burned (%)

Example The amount of residue from U.S. wheat production available for combustion in 1990 is calculated as follows:

$$135,083,700,000 \text{ lbs} \times 1.3 \text{ lbs residue/lb crop product} \times 0.10 \text{ residue burned } in situ \times 0.911 \\ \text{dry matter content} \times 0.93 \text{ fraction burned} = 14,878,105,210 \text{ lbs}$$

Step (3) Calculate Total Carbon Burned (Table 11-2 , Columns G-J)

- For each crop, take the amount of dry matter (DM) burned (estimated in step (2) -- column F) and enter it in column G of Table 11-2. Next, multiply the amount of DM burned by the fraction of carbon contained in the fuel to obtain total amount of C burned. Carbon contents for selected crop residues are presented in Table 11-2. An average value of 0.45 lbs C/lb dry matter can be used if data are not available.

$$\text{Dry Matter Burned (lbs)} \times \text{Carbon Content of the Residue (lbs C/lb dm)} = \text{Total Carbon Burned (lbs)}$$

Example The total amount of carbon burned from U.S. wheat residue in 1990 is calculated as follows:

$$14,878,105,210 \text{ lbs dm} \times 0.4853 \text{ (lbs C/lb dm)} = 7,220,344,458 \text{ lbs C}$$

Step (4) Estimate Emissions of CH₄ and CO (Tables 11-2, Columns G-M)

- For each crop, multiply the amount of carbon burned (column I) by the fraction oxidized, 88 percent (column J), to obtain the amount of carbon dioxide released instantaneously in units of carbon (columns I x J).

$$\text{Total Carbon Burned (lbs C)} \times 88\% \text{ (Fraction Oxidized)} = \text{Amount of CO}_2 \text{ Released (lbs CO}_2\text{-C)}$$

- For each crop, multiply the amount of CO₂ released in units of carbon by the emission ratios of CH₄ (column P) and CO (column R) relative to CO₂-C (see Table 11-2, columns P and R) to obtain emissions of CH₄ and CO in units of carbon.

$$\text{Amount of CO}_2 \text{ Released (lbs CO}_2\text{-C)} \times (0.003) = \text{CH}_4 \text{ Emissions (lbs CH}_4\text{-C)}$$

$$\text{Amount of CO}_2 \text{ Released (lbs CO}_2\text{-C)} \times (0.06) = \text{CO Emissions (lbs CO-C)}$$

Example CH₄-C and CO-C emissions from burning of residue from U.S. wheat production in 1990 is calculated as follows:

$$\text{Carbon Oxidized: } 7,220,344,458 \text{ lbs C} \times 88\% = 6,353,903,123 \text{ lbs CO}_2\text{-C}$$

$$\text{CH}_4\text{-C Emissions: } 6,353,903,123 \text{ lbs CO}_2\text{-C} \times 0.003 = 19,061,709 \text{ lbs CH}_4\text{-C}$$

$$\text{CO-C Emissions: } 6,353,903,123 \text{ lbs CO}_2\text{-C} \times 0.06 = 381,234,187 \text{ lbs CO-C}$$

Step (5) Estimate Nitrogen Content of the Dry Matter (Table 11-2, Columns I, J, and L)

- For each crop, multiply the amount of carbon burned by the fraction oxidized and the nitrogen to carbon content of the fuel. Nitrogen to carbon ratios for selected crop residues are presented in Table 11-2, column L. An average value of 0.23 lbs N/lb dry matter can be used if data are not available.

$$\text{Carbon Burned (lbs C)} \times \text{Fraction Oxidized (\%)} \times \text{Nitrogen/Carbon (lbs N/lbs C)} = \text{Total Nitrogen Released (lbs N)}$$

Example The total amount of nitrogen released from U.S. wheat residue in 1990 is calculated as follows:

$$\text{Nitrogen Released: } 7,220,344,458 \text{ lbs C} \times 88\% \times 0.0082 \text{ (lbs N/lbs C)} = 52,102,006 \text{ lbs N}$$

Step (6) Estimate Emissions of N₂O and NO_x (Table 11-2, Columns O, T and V)

- For each crop, multiply the amount of nitrogen released in units of nitrogen by the emission ratios of N₂O (column T) and NO_x (column V) relative to N (see Table 11-2, columns U and W) to obtain emissions of N₂O and NO_x in units of nitrogen.

$$\text{Amount of N Released (lbs)} \times (0.007) = \text{N}_2\text{O Emissions (lbs N}_2\text{O-N)}$$

$$\text{Amount of N Released (lbs)} \times (0.121) = \text{NO}_x \text{ Emissions (lbs NO}_x\text{-N)}$$

Example N₂O-N and NO_x-N emissions from burning of residue from U.S. wheat production in 1990 are calculated as follows:

$$\text{N}_2\text{O-N Emissions: } 52,102,006 \text{ lbs N} \times 0.007 = 364,714 \text{ lbs N}_2\text{O-N}$$

$$\text{NO}_x\text{-N Emissions: } 52,102,006 \text{ lbs N} \times 0.121 = 6,304,343 \text{ lbs N}_2\text{O-N}$$

Step (7) Convert to Tons of Full Molecular Weights

- For each crop, multiply the emission estimates of CH₄, CO, N₂O, and NO_x by 16/12, 28/12, 44/28, and 46/14, respectively, to convert to full molecular weights.
- For each gas, sum across all crop types to produce total emissions from burning of crop residues. Divide the results by 2000 to obtain total emissions in tons.

Example

Emissions of CH₄, CO, N₂O, and NO_x from burning of residue from U.S. wheat production in 1990 are converted to tons of their full molecular weights as follows:

CH ₄ Emissions:	19,061,709 lbs CH ₄ -C x (16/12) ÷ 2000 lbs/ton = 12,708 tons CH ₄
CO Emissions:	381,234,187 lbs CO-C x (28/12) ÷ 2000 lbs/ton = 444,773 tons CO
N ₂ O Emissions:	364,714 lbs N ₂ O-N x (44/28) ÷ 2000 lbs/ton = 287 tons N ₂ O
NO _x Emissions:	6,304,343 lbs NO _x -N x (46/14) ÷ 2000 lbs/ton = 10,357 tons NO _x

Table 11-2: Emissions from Agricultural Residue Burning Worksheet

A B C D E F
(A x B x C x D x E)

Crop Type	Crop Production (lbs)	Residue/Crop Ratio	Residue Burned (%)	Dry Matter (%)	Fraction Burned (%)	Dry Matter (lbs)
<u>CEREALS</u>						
Wheat		1.3	10	91.1	93	
Barley		1.2	10	90.4	93	
Maize		1	10	88	93	
Oats		1.3	10	90.6	93	
Rye		1.6	10	90	93	
Rice		1.4	10	90	93	
Millet		1.4	10	88.5	93	
Sorghum		8	10	90	93	
Total						
<u>PULSE</u>						
Soya		2.1	10	89.3	93	
Beans		2.1	10	88.7	93	
Peas		1.5	10	90.2	93	
Lentils		2.1	10	89.3	93	
Total						
<u>TUBER and ROOT</u>						
Sugarbeet		0.3	10	90	93	
Artichoke		0.8	10	90	93	
Peanut		1	10	90.1	93	
Potatoes		0.4	10	86.7	93	
Feedbeet		0.4	10	86.7	93	
Total						
SUGARCANE		0.8	10	90	93	

Table 11-2 Continued

<i>G</i> (Column F)	<i>H</i>	<i>I</i> (G x H)	<i>J</i>	<i>K</i> (I x J)	<i>L</i>	<i>M</i> (I x J x L)
Crop Type	Dry Matter (lbs DM)	Carbon Content (% C/DM)	Total C Burned (lbs C)	Fraction Oxidized (%)	Total Carbon Oxidized (lbs CO ₂ /C)	Nitrogen/Carbon Ratio (lbs N/C)
CEREALS						Total Nitrogen Released (lbs N)
Wheat		48.53		88		0.0082
Barley		45.67		88		0.0026
Maize		47.09		88		0.0172
Oats		48.53		88		0.0144
Rye		48.53		88		0.0144
Rice		41.44		88		0.0162
Millet		48.53		88		0.0144
Sorghum		48.53		88		0.0175
Total						
PULSE						
Soya		45		88		0.0511
Beans		45		88		0.0511
Peas		45		88		0.0511
Lentils		45		88		0.0511
Total						
TUBER and ROOT						
Sugarbeet		40.72		88		0.056
Artichoke		42.26		88		0.026
Peanut		42.26		88		0.026
Potatoes		42.26		88		0.026
Feedbeet		42.26		88		0.026
Total						
SUGARCANE		46.95		88		0.0064

Table 11-2 *continued*

<i>N</i> (Column K)	<i>O</i> (Column M)	<i>P</i>	<i>Q</i> (<i>N</i> x <i>P</i> ÷ 2000)	<i>R</i>	<i>S</i> (<i>N</i> x <i>R</i> ÷ 2000)	<i>T</i>	<i>U</i> (<i>O</i> x <i>T</i> ÷ 2000)	<i>V</i>	<i>W</i> (<i>O</i> x <i>V</i> ÷ 2000)	
Crop Type	Total Carbon Oxidized (lbs CO ₂ -C)	Total Nitrogen Released (lbs N)	CH ₄ Emissions Ratio	CH ₄ Emitted (tons CH ₄ -C)	CO Emissions Ratio	CO Emitted (tons CO-C)	N ₂ O Emissions Ratio	N ₂ O Emitted (tons N ₂ O-N)	NO _x Emissions Ratio	NO _x Emitted (tons NO _x -N)
CEREALS										
Wheat			0.003		0.06		0.007		0.121	
Barley			0.003		0.06		0.007		0.121	
Maize			0.003		0.06		0.007		0.121	
Oats			0.003		0.06		0.007		0.121	
Rye			0.003		0.06		0.007		0.121	
Rice			0.003		0.06		0.007		0.121	
Millet			0.003		0.06		0.007		0.121	
Sorghum			0.003		0.06		0.007		0.121	
Total										
PULSE										
Soya			0.003		0.06		0.007		0.121	
Beans			0.003		0.06		0.007		0.121	
Peas			0.003		0.06		0.007		0.121	
Lentils			0.003		0.06		0.007		0.121	
Total										
TUBER and ROOT										
Sugarbeet			0.003		0.06		0.007		0.121	
Artichoke			0.003		0.06		0.007		0.121	
Peanut			0.003		0.06		0.007		0.121	
Potatoes			0.003		0.06		0.007		0.121	
Feedbeet			0.003		0.06		0.007		0.121	
Total										
SUGARCANE			0.003		0.06		0.007		0.121	

WORKBOOK 12

METHANE EMISSIONS FROM MUNICIPAL WASTEWATER

Wastewater can be treated using aerobic and/or anaerobic technologies, or if untreated, can degrade under either aerobic or anaerobic conditions. Methane is produced when organic material in treated and untreated wastewater degrades anaerobically, i.e., without the presence of oxygen. Highly organic wastewater streams such as waste streams from food processing or pulp and paper plants rapidly deplete available oxygen in the water stream as their organic matter decomposes. The organic content, otherwise known as "loading" of these wastewater streams, is expressed in terms of biochemical oxygen demand, or "BOD." BOD represents the amounts of oxygen taken up by the organic matter in the wastewater during decomposition. Under the same conditions, wastewater with higher BOD concentrations will produce more methane than wastewater with relatively lower BOD concentrations.

To estimate methane emissions from municipal wastewater, the following steps are required: (1) obtain the required data on state population; (2) estimate biochemical oxygen demand (BOD_5); (3) estimate gross annual methane emissions; and (4) estimate net annual methane emissions. These steps are outlined in detail below. A description of the methodology presented here, as well as an alternative, more precise methodology, is provided in Discussion Section 12.

The following equation summarizes the methane emissions calculation from municipal wastewater:

$$\frac{\text{lbs } CH_4}{\text{yr}} = (\text{Population}) \left(\frac{\text{lbs } BOD_5}{\text{capita/day}} \right) \left(\frac{365 \text{ days}}{\text{yr}} \right) \left(\frac{0.22 \text{ lbs } CH_4}{\text{lbs } BOD_5} \right) \left(\begin{array}{c} \text{Fraction} \\ \text{Anaerobically} \\ \text{Digested} \end{array} \right) - (\text{Methane Recovered})$$

Step (1) Obtain Required Data

- *Required Data.* The information needed to calculate methane emissions from municipal wastewater are (1) lbs BOD_5 per capita; (2) state population; (3) the fraction of total wastewater that is treated anaerobically (wastewater treatment methods that may result in anaerobic decomposition of waste are sewer systems and septic tanks). Because published data on the fraction of wastewater that is anaerobically treated is scarce, states are encouraged to provide their own estimates based on their available data. This section, however, contains default values for the fraction of wastewater that is treated anaerobically; and (4) amount of methane that is recovered.
- *Data Source.* Population data can be obtained from state agencies responsible for handling demographic or census information. Information on biochemical oxygen demand and wastewater characteristics can be obtained from *National Small Flows Clearinghouse* (West Virginia University), *Water Supply and Pollution Control* (Viessman and Hammer, 1985), *Emissions and Mitigation at Landfills and Other Waste Management Facilities* (Thorneloe, 1992), and state and local public works agencies.
- *Units for Reporting Data.* Population data should be reported in units of 1,000 persons.

Biochemical Oxygen Demand data should be reported in pounds per day.

Step (2) Estimate Biochemical Oxygen Demand (Table 12-1, Columns A, B, and C)

- Enter the total state population for 1990, in 1,000 persons, in Table 12-1, column A. Enter wastewater BOD Generation Rate in Table 12-1, column B. (A default value of 0.1356 lbs/capita/day can be used if state-specific data are unavailable). Multiply the population by wastewater BOD generation rate to give annual BOD generated. Enter the result in pounds BOD_5 , in Table 12-1, column C.

$$\begin{aligned} \text{Population (1,000 persons)} \times \text{BOD Generation Rate (lbs/capita/day)} \\ = \text{BOD}_5 \text{ Generated (lbs/day)} \end{aligned}$$

Example A state that has a current population of 2 million people would calculate their BOD_5 generated as follows:

$$2,000 \text{ (1,000 persons)} \times 0.1356 \text{ lbs/capita/day} = 271,200 \text{ lbs/day}$$

Step (3) Estimate Methane Emissions (Table 12-1, Columns C, D, E, F, and G)

- Enter Fraction of BOD anaerobically treated in Table 12-1, column D. Default value of 15 percent can be used if state-specific factors are unavailable.
- Multiply annual BOD generated by the fraction of BOD anaerobically treated and 365 days/yr to give quantity of BOD treated anaerobically per year. Enter this result, in pounds BOD_5 , in column E.

$$\begin{aligned} \text{BOD}_5 \text{ Generated (lbs BOD}_5\text{/day)} \times \text{Fraction of BOD}_5 \text{ Anaerobically Treated} \times 365 \text{ days/yr} \\ = \text{BOD}_5 \text{ Anaerobically Treated (lbs BOD}_5\text{/yr)} \end{aligned}$$

Example BOD_5 anaerobically treated per year in the state is estimated as follows:

$$271,200 \text{ (lbs BOD}_5\text{/day)} \times 0.15 \times 365 \text{ (days/yr)} = 14,848,200 \text{ (lbs BOD}_5\text{/yr)}$$

- Enter the methane emissions factor, in pounds $\text{CH}_4/\text{lb BOD}_5$, in column F. The recommended emissions factor is 0.22 lbs $\text{CH}_4/\text{lb BOD}_5$.
- Multiply the quantity of BOD treated anaerobically by the methane emissions factor to give total methane emissions. Enter the result in pounds CH_4 in column G.

$$\begin{aligned} \text{BOD}_5 \text{ Treated Anaerobically} \times \text{Methane Emissions Factor (lbs CH}_4\text{/lb BOD}_5\text{)} \\ = \text{Methane Emissions (lbs CH}_4\text{)} \end{aligned}$$

Example Gross methane emissions from wastewater treatment in the state are calculated as follows:

$$14,848,200 \text{ (lbs BOD}_5/\text{yr}) \times 0.22 \text{ lbs CH}_4/\text{lbs BOD}_5 = 3,266,604 \text{ lbs CH}_4/\text{yr}$$

Step (4) Estimate Net Annual Methane Emissions (Table 12-1, Columns G, H, and I)

- Estimate the amount of methane recovered (if any) from municipal wastewater treatment. Enter the result, in pounds CH₄, in column H.
- Subtract methane recovered from total methane emissions to give net methane emissions. Divide result by 2,000 to obtain CH₄ emissions in tons CH₄. Enter the result, in tons CH₄, in column I.

$$\begin{aligned} \text{Methane Emissions (lbs CH}_4) - \text{Methane Recovered} &\div 2,000 \text{ lbs/ton} \\ &= \text{Net Methane Emissions (tons CH}_4) \end{aligned}$$

Example A state that recovers 15 percent of the methane generated from wastewater treatment would calculate their net emissions, in tons CH₄, as follows:

$$3,266,604 \text{ lbs/CH}_4 - (0.15 \times 3,266,604 \text{ lbs CH}_4) \div 2,000 = 1,388 \text{ tons CH}_4$$

Table 12-1. Methane Emissions from Municipal Wastewater Treatment Worksheet

A	B	C <i>(A x B)</i>	D	E <i>(C x D x 365)</i>	F	G <i>(E x F)</i>	H	I <i>(G x H ÷ 2,000)</i>
Population (1,000 persons)	Wastewater BOD Generation Rate (lbs BOD ₅ /1,000 persons/day)	BOD Generated (lbs BOD ₅)	Fraction Anaerobically Treated	Quantity of BOD Treated Anaerobically (lbs BOD ₅ /yr)	Methane Emission Factor (lbs CH ₄ /lb BOD ₅)	CH ₄ Emissions (lbs CH ₄)	Methane Recovered (lbs CH ₄)	Net CH ₄ Emissions (tons CH ₄)

PART II

DISCUSSION SECTIONS

DISCUSSION 1

CARBON DIOXIDE EMISSIONS FROM COMBUSTION OF FOSSIL AND BIOMASS FUELS

CO₂ EMISSIONS FROM THE COMBUSTION OF FOSSIL FUELS

OVERVIEW

Energy-related activities are the most significant contributor to U.S. greenhouse gas emissions, accounting for nearly 89 percent of total emissions in 1990. Emissions from fossil fuel combustion comprise the vast majority of these energy-related emissions. These emissions were produced from a variety of fossil fuel combustion activities, including heating in residential and commercial buildings, energy combustion to generate electricity, steam production for industrial processes, and gasoline consumption in automobiles and other vehicles. As fossil fuels burn, they emit carbon dioxide (CO₂) as a result of oxidation of the carbon in the fuel. In 1990, CO₂ accounted for 96 percent of all greenhouse gas emissions from fossil fuel combustion. The remaining 4 percent can be attributed to emissions of other gases, such as carbon monoxide (CO), methane (CH₄), or nonmethane volatile organic compounds (NMVOCs), which are emitted as a by-product of incomplete combustion. These gases are then oxidized to CO₂ within anywhere from a few days to 10 to 11 years. For purposes of this analysis, however, emissions of these other gases are considered to be a subset of CO₂ emissions. That is, all carbon emitted to the atmosphere is reported as CO₂ emissions, while a much smaller portion of the carbon will also be reported as these other gases. This "double counting" is intentional. By reporting emissions in this fashion, state estimates of CO₂ will reflect total loadings of carbon to the atmosphere. Also, since all of these gases oxidize to CO₂ eventually, they should be viewed as a subset of carbon emitted as CO₂.

The amount of CO₂ emitted from fossil fuel combustion is related directly to the type and amount of fuel consumed, the fraction of the fuel that is oxidized, and the carbon content of the fuel. This relationship can be described in two parts:

- 1) The amount of carbon contained in the fuel per unit of useful energy produced varies among different fuel types. For example, coal contains the highest amount of carbon per useful unit of energy. Petroleum has about 80 percent of the carbon per unit of energy as compared to coal, and natural gas has about 55 percent. Even within fuel types, carbon contents will vary, e.g., the lower the quality of the coal (such as lignite and sub-bituminous coal), the higher the carbon content coefficient (*i.e.*, more carbon emitted per unit of energy). There are similar carbon differences among the different types of liquid fuels and natural gas as well.
- 2) Not all carbon in fuel products is oxidized to CO₂ because of (1) inefficiencies in the combustion process that leave carbon unburned, and (2) non-fuel uses of the energy, such as asphalt, naphtha, and lubricants. During the combustion of fossil fuels not all of the carbon in the fuel oxidizes to CO₂, which causes a small fraction of the carbon to remain unburned as soot or ash. Similarly, some carbon is not immediately and completely oxidized to CO₂, and is emitted in the form of CH₄ or other hydrocarbons. Fossil fuels are also used for non-energy purposes,

primarily as a feedstock for such items as fertilizer, lubricants, and asphalt. In some cases, as in fertilizer production, the carbon from the fuels is oxidized quickly to CO₂. In other cases, as in asphalt production, the carbon is sequestered in the product, sometimes for as long as several centuries.

DESCRIPTION OF WORKBOOK METHOD

The first step in estimating CO₂ emissions from fossil fuel combustion is to define exactly what is meant by "CO₂ emissions." For this discussion, CO₂ emissions from fossil fuel combustion include all of the carbon in fuels that is either immediately oxidized or oxidized within a short time period (*i.e.*, less than 20 years). It includes carbon in the form of gases, like CO and CH₄, and carbon in short lived products that will be burned after use or decompose quickly. CH₄ emissions from oil and gas production and coal mining as well as CH₄, CO, N₂O, NO_x and NMVOC emissions from stationary and mobile source combustion are not included in this section but are discussed later (see Workbook and Discussion Sections 3, 4, 13, and 14, respectively).

To calculate CO₂ emissions from fossil fuel combustion, the following factors must be identified:

- 1) Fossil fuel consumption by energy type;
- 2) Carbon content coefficients;
- 3) Carbon sequestered in products for long periods of time;
- 4) Carbon emitted from bunker fuel consumption;
- 5) Carbon emitted from interstate electricity consumption; and
- 6) Carbon oxidized during combustion.

Fossil Fuel Consumption

As noted above, CO₂ is released as fossil fuels are consumed. The carbon content of these fuels typically varies by fuel type. Therefore, in order to develop an accurate estimate of CO₂ emissions, it is necessary to compile individual consumption data for each type of fuel consumed. A recommended list of fuels is given in Table D1-1. It should be noted that certain primary fuels (such as crude oil) do not appear on this list. This is because primary fuels of this nature are not combusted directly, but rather are transformed into secondary fuels (such as gasoline) which are combusted. Therefore, the carbon in these primary fuels is accounted for in the secondary fuels. Fugitive emissions of greenhouse gases from primary fuel production, processing, and distribution are included elsewhere (see Workbook and Discussion Sections 3 (natural gas and oil) and 4 (coal)).

Fuel statistics should be provided on an energy basis (preferably in million Btu), since considerable variation exists in the energy content per weight of fossil fuels. Statistics using other units, such as barrels or short tons, can be used, but require conversion to energy units. If conversion is necessary, the conversion factors used should be reported. Default conversion factors for the various fuel types are presented in Table D1-1. It should be noted that these conversion factors are national averages based on 1990 data and may not accurately reflect the energy content of fuels used in a particular state or for years other than 1990. The degree of variation geographically and temporally is less significant for natural gas and refined petroleum fuels than for coal, which may vary significantly from mine to mine and year to year. State specific thermal conversion factors for coal are compiled by the Energy Information

Table D1-1. Conversion Factors to Million Btu.^a

Fuel Type	If data is in	Multiply by
<i>Petroleum</i>		
Asphalt and Road Oil	barrels	6.636
Aviation Gasoline	barrels	5.048
Distillate Fuel Oil	barrels	5.825
Jet Fuel: Kerosene Type	barrels	5.670
Jet Fuel: Naphtha Type	barrels	5.355
Kerosene	barrels	5.670
Liquified Petroleum Gases	barrels	4.011
Lubricants	barrels	6.065
Miscellaneous Petroleum Products and Crude Oil	barrels	5.800
Motor Gasoline	barrels	5.253
Naphtha (<104°F) ^b and Special Naphthas	barrels	5.248
Other Oil (>104°F) ^b and	barrels	5.825
Unfinished Oils		
Pentane Plus	barrels	4.620
Petroleum Coke	barrels	6.024
Residual Fuel Oil	barrels	6.287
Still Gas ^b	barrels	6.000
Waxes	barrels	5.537
<i>Coal^c</i>		
Anthracite ^e	short tons	21.668
Bituminous	short tons	23.89
Sub-bituminous	short tons	17.14
Lignite	short tons	12.866
Coal Coke	short tons	24.800
<i>Natural Gas</i>	billion cubic feet	1.03 x 10 ⁶
	Teracalories	3968
<i>Biofuels</i>		
Wood ^d	Btu	0.116x10 ³ (lbs/Btu)
Ethanol	gallons	0.764
<i>Interstate Electricity Consumption^f</i>	kilowatthours	10,000 (Btu/kWh)
a. Heat contents of many fuels vary somewhat by source, year, and consumer. Except for coal, biomass, and blended petroleum products, this variation tends to be relatively small. The values here are national averages for 1990.		
b. By EIA definition naphtha (<104°F), other oil (>104°F), and still gas are collectively termed petrochemical feedstocks.		
c. Thermal conversion factors for coal can vary extensively by source. More complete state and sector specific factors are available through U.S. DOE/EIA.		
d. The energy content of wood varies with moisture content and type of wood. The conversion factor given is a nationally averaged value based on dry mass of hardwood. Since wood consumption figures should be in pounds, the factor should be used to convert consumption from Btu to pounds.		
e. The anthracite factor presented here is a national average. Actual anthracite factors could range from as low as 17.5 MMBtu/ton for anthracite reclaimed from refuse piles to 26 MMBtu/ton or higher for anthracite mined directly from the original seam.		
f. This is a national average heat rate based on EIA data (EIA, 1994e) and should only be used for interstate electricity consumption for which the specific heat rate of the source is unknown.		
Source: Petroleum, natural gas, and wood heat-equivalents and the interstate electricity heat rate are from EIA's <i>Annual Energy Review 1993</i> . Coal heat-equivalents are from EIA's <i>State Energy Data Report 1992, Cost and Quality of Fuels for Electric Utility Plants</i> , and <i>Quarterly Coal Report</i> . Ethanol heat-equivalents are from EIA's <i>Estimates of U.S. Biomass Consumption 1992</i> .		

Administration (EIA) of the U.S. Department of Energy (DOE) and presented in a variety of sources. For example, representative energy-content information based on a survey of electric utility power plants is contained in EIA's annual *Cost and Quality of Fuels for Electric Utility Plants*, while more generalized information is provided in the *Quarterly Coal Report* and *State Energy Data Report*.

Next, fuel consumption data should be disaggregated into the following consumption sectors: residential, commercial, industrial, transportation, and electric utility. Sector-specific consumption figures for all 50 states can be found in *State Energy Data Report 1992* (EIA, 1994b). In many instances, states may find it useful to distribute emissions from electric utilities across "end-use sectors," to assist in formulating emission reduction strategies. To distribute utility emissions accurately, it is necessary to obtain electricity consumption data by each of the four end-use sectors (residential, commercial, industrial, and transportation) in the state. Default values for this consumption can be obtained from *State Energy Data Report 1992* (EIA, 1994b). Using these figures, states can calculate the fraction of total electricity consumption which is consumed by each of the four end-use sectors (*i.e.*, divide each sector specific consumption figure by total electricity consumption). Each of these fractions is then multiplied by total emissions from the utility sector, resulting in the portion of utility emissions attributable to each end-use sector. These end-use emissions from electricity consumption are then added to the other sectoral emissions.

Determine and Apply the Appropriate Carbon Content Coefficients

Carbon content coefficients represent the amount of carbon emitted per unit of useful energy obtained by burning a specific type of fuel. Carbon content coefficients vary considerably both between and within the major fuel types, as noted below:

- For natural gas, the carbon content depends heavily on the composition of the gas, which includes methane, ethane, propane, other hydrocarbons, CO₂, and other gases. The relative proportions of these gases vary from one gas production site to another.
- For crude oil, Marland and Rotty (1984) suggest that the API gravity¹ acts as an indicator of the carbon/hydrogen ratio. Carbon content per unit of energy is usually less for light refined products such as gasoline than for heavier products such as residual fuel oil.
- For coal, carbon emissions per ton vary considerably depending on the coal's composition of carbon, hydrogen, sulfur, ash, oxygen, and nitrogen. While variability of carbon emissions on a mass basis can be considerable, carbon emissions per unit of energy (*e.g.*, per Btu) vary much less, with lower ranked coals such as sub-bituminous and lignites usually containing slightly more carbon than higher-ranked coals.

In general, carbon content coefficients are determined based on the composition and heat contents of fuel samples. Several studies have tried to estimate carbon content coefficients for fossil fuels (Marland and Rotty, 1984; Marland and Pippin, 1990; Grubb, 1989; IPCC/OECD, 1994; and others). Based on these studies and detailed fuel data, the Energy Information Administration of DOE estimates carbon content

¹ Variations in petroleum are most often expressed in terms of specific gravity at 15 degrees C. The API gravity, where API gravity = 141.5/specific gravity - 131.5, is an indication of the molecular size, carbon/hydrogen ratio, and hence carbon content of a crude oil.

Table D1-2: Carbon Content Coefficients for Fuel Combustion^a
 (lbs C/10⁶ Btu)

Fuel Consumed	Carbon Coefficient
Asphalt and Road Oil	45.5
Aviation Gas	41.6
Distillate Fuel Oil	44.0
Jet Fuel (all kinds)	43.5
Kerosene	43.5
LPG	37.8
Lubricants	44.6
Motor Gasoline	42.8
Residual Fuel Oil	47.4
Misc. Petroleum Products and Crude Oil	44.7
Naphtha (<104°F)	40.0
Other Oil (>104°F)	44.0
Pentanes Plus	40.2
Petrochemical Feed	42.7
Petroleum Coke	61.4
Still Gas	38.6
Special Naphtha	43.8
Unfinished Oils	44.6
Waxes	43.7
Anthracite Coal	62.1
Bituminous Coal	56.0
Sub-bituminous Coal	57.9
Lignite Coal	58.7
Natural Gas	31.9
Wood ^b	0.475
Ethanol	41.8

Except as noted all coefficients are given as pounds of carbon emitted per million Btu of fuel consumed (lbs C/10⁶ Btu). When multiplied by consumption in 10⁶ Btu, or pounds for wood, they result in emissions of carbon in pounds (lbs C).

a. Carbon content coefficients are sometimes called carbon emission coefficients or carbon coefficients.

b. The wood coefficient is a percent of total carbon in biomass (%C).

Sources: Natural gas and petroleum coefficients are from U.S. EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1993*. Coal coefficients are full combustion figures based on EIA's *Emissions of Greenhouse Gases in the United States: 1985-1990*. The wood carbon fraction is from the *IPCC Guidelines for National Greenhouse Gas Inventories*. The ethanol coefficient is from OTA's *Changing by Degrees*.

coefficients for a wide range of fuel types. Nationally averaged carbon content coefficients for each fuel type are listed in Table D1-2. As with thermal conversion factors, these average carbon emission factors may not precisely reflect the carbon content of energy used in a particular state or for years other than 1990. The degree of variation geographically and temporally is generally quite small for natural gas and refined petroleum fuels, but coal coefficients may vary significantly from mine to mine and year to year. Nationally averaged figures can be found in U.S. EPA (1994) and non-type-specific state factors can be found in DOE's *Electric Power Annual*. States are encouraged to use more detailed data if it is available and well documented.

Once determined, carbon content coefficients can then be used to calculate the total potential carbon that could be released from the combustion of fossil fuels. The basic approach for implementing this methodology relies on the following equation:

$$TC_{ij} = C_{ij} \times CCC_i$$

where: TC_{ij} = Total Carbon contained in fuel i, which is consumed in sector j (pounds);

C_{ij} = Consumption of fuel i in sector j (million Btu); and

CCC_i = Carbon Content coefficient for fuel i (lbs C / million Btu)

By summing TC_i across all fuels and sectors one can calculate a state's total potential carbon emissions from the combustion of fossil fuels.

Carbon Sequestered in Products

After estimating the total carbon contained in the fuels, the next step is to estimate the amount of carbon from these fuels that is sequestered in non-energy products for a significant period of time (e.g., greater than 20 years). All fossil fuels are used for non-energy purposes to some degree. For example, natural gas is used for ammonia production; LPGs are used for a number of purposes, including production of solvents and synthetic rubber; oil refineries produce wide variety of non-fuel products, including asphalt, naphthas, and lubricants; and coal is used to produce coke, yielding crude light oil and crude tar as by-products which are used in the chemical industry.

However, not all non-energy uses of fossil fuels result in carbon sequestration. For example, the carbon from natural gas used in ammonia production is oxidized quickly; many products from the chemical and refining industries are burned or decompose within a few years; and the carbon in coke is oxidized when the coke is used.

The approach used to determine the portion of carbon sequestered in products is basically similar to that used by Marland and Rotty (1984) and modified by later information (Grubb, 1989; Okken and Kram, 1990; IPCC/OECD 1994; U.S. EPA, 1994), in which historical data and product knowledge are used to determine non-energy applications which sequester carbon for long periods of time. Additional non-fuel data is being collected by the EIA. Based on these data, the following carbon storage assumptions have been made:

- *Coal (i.e., Coal Oil and Tars):* Based on Marland and Rotty (1984), approximately 6 percent of coal carbon entering coke plants is converted to coal oils and tars, of which 75 percent is sequestered and remains unoxidized for long periods of time.
- *Natural Gas:* The two main non-fuel uses of natural gas are for ammonia production and nitrogenous fertilizer manufacture and as a chemical feedstock. It is assumed that 100 percent of the carbon in natural gas used as a chemical feedstock is sequestered. As noted above, the carbon from natural gas used in ammonia production oxidizes quickly, and is not sequestered.
- *LPG:* It is assumed that 80 percent of the carbon in LPG sold for chemical and industrial uses is sequestered in products.
- *Asphalt and Road Oil (i.e., Bitumen):* It is assumed that 100 percent of the carbon in this product is sequestered indefinitely.

- *Lubricants*: Of the carbon contained in lubricants (e.g., automotive oil, grease, etc.), approximately 50 percent is assumed to remain unoxidized for long periods of time.
- *Petrochemical Feedstocks*: This category includes naphthas (<104°F) and other petroleum products used as chemical feedstocks in petroleum related industries. Eighty percent of the carbon in this category is assumed to end up in products such as plastics, tires, and fabrics, which sequester carbon over long periods of time.
- *Waxes and Miscellaneous Products*: Waxes and miscellaneous products is an EIA defined category which includes waxes and various other petroleum products used for non-fuel purposes. Until more exact information is available, 100 percent of the carbon contained in these products is assumed to be sequestered. For example, the carbon contained in waxes for food industry wrappers is assumed to be sequestered in landfills.

These assumptions comprise the default values to be used by states (see Table D1-3). As more detailed information on non-fuel uses of fossil fuels becomes available, estimates of the fraction of carbon stored will change accordingly. States should use the most up-to-date information available, and document their assumptions carefully.

Table D1-3: Percent of Carbon Sequestered by Non-fuel Uses^a

Fuel Type	Fraction Stored
Coal Oils and Tars from coke production	0.75
Natural Gas as a chemical feedstock	1.00
Asphalt and Road Oil	1.00
LPG	0.80
Lubricants	0.50
Petrochemical Feedstocks ^a	0.80
Waxes and Miscellaneous Products ^b	1.00

a. By EIA definition, "Petrochemical Feedstocks" include naphtha (<104°F), other oil (<104°F), and still gas.
 b. By EIA definition, "Waxes and Miscellaneous Products" includes waxes, other miscellaneous petroleum products, residual fuel oil, and distillate fuel oil.
Sources: Figures for coal oil and tars, asphalt and road oil, LPG, and lubricants are from Marland and Rotty (1984). The Figure for natural gas is from communication with EIA (Rypinski, 1994). Petrochemical feedstocks and waxes and miscellaneous products are from U.S. EPA (1994).

Using the carbon sequestration percentages listed above, the suggested approach for estimating carbon sequestered in products for each state starts with the following basic equation:

$$CS_i = U_i \times CCC_i \times FS_i$$

where: CS_i = Carbon Sequestered in product i (lbs of carbon);

U_i = Non-fuel use of energy for product i (million Btu);

CCC_i = Carbon Content Coefficient for product i (lbs C / million Btu); and

FS_i = Fraction of carbon in product i which is Sequestered.

Total carbon sequestered in products can be determined by summing CS_i over the various products. The resulting carbon sequestration estimates from non-energy uses of fossil fuels would be considered "potential" emissions and are subtracted from the total emissions of carbon in the state that produces the products. When estimating emissions sector-by-sector, it is suggested that sequestered carbon from these products be assigned to the industrial sector, unless justification for allocating certain products to another sector can be clearly demonstrated.

Carbon Emitted from Bunker Fuel Consumption

For inventory purposes there are two kinds of bunkers: domestic bunkers and international bunkers. Domestic bunkers include fuel supplied to vehicles (aircraft, autos, ships, etc.) for use in interstate transportation. Since it is extremely difficult to obtain accurate activity data on interstate transportation, there is currently no method to explicitly determine emissions from domestic bunker fuel consumption. Since general emissions calculations are consumption based, all emissions from interstate transportation should automatically be included such statistics. Therefore, it is assumed that emissions from all such bunkers will effectively captured in normal state consumption statistics and domestic bunkers should not be specifically addressed.

International bunker fuel is fuel which originates in a state, but is supplied to ships and aircraft which consume it during international transport activities. For example, distillate fuel, residual fuel, and jet fuel may be sold in a state and be consumed by vehicles which leave the U.S. Since, this fuel is not combusted solely in the U.S., its emissions cannot be clearly attributed to the U.S. In accordance with international inventory practices (IPCC, 1994) emissions from international bunkers should be calculated and reported by the state of origin, but not included in the state's total emission figures. In this way, emissions from these sources can be quantified without attributing undo emissions to the U.S. or any state therein.

International bunker fuel emissions are calculated in the same manner as other emissions from fossil fuel combustion. Once consumption of international bunker fuels are determined, they are multiplied by their appropriate carbon content coefficients (see Table D1-2). This results in the amount of carbon potentially emitted by combustion of these fuels. This figure should be reported and clearly labeled in the state's inventory. These emissions should be subtracted from the state total emissions *only* if they have already been captured in the state-wide figures.

Once adjustments have been made to state totals for carbon sequestered and emissions from international bunker fuel consumption, the resulting figure is the "Net Carbon Content," or "Net Potential Emissions."

Carbon Emitted from Interstate Electricity Consumption

Not only can fuels be imported and exported from a state, but electricity derived from these fuels can be transported across state boundaries (*i.e.* electricity is often produced in one state for consumption in another). For various reasons (*e.g.*, mitigation and impact assessments) it is necessary to attribute emissions from electricity consumption to end-use consumers rather than to the generating state. However, actual emissions from electricity consumption occur in the generating state and are captured in that state's consumption figures.

To provide the most complete picture of emissions at the state level, states should calculate emissions due to interstate electricity flux in addition to the emissions calculated directly from fossil fuel consumption. In other words, states should calculate and report emissions from all fuel consumption within their boundaries, *including* that which is converted to electricity consumed out of state. To clarify consumption patterns, the state should also perform separate calculations for emissions due to electricity traded across state boundaries, which is discussed below. These emissions should not be used to adjust state emission totals, but should be clearly provided for informational purposes.

Four pieces of information are required to determine emissions from interstate electricity consumption:

- 1) The quantity of electricity imported to and exported from other states;
- 2) The sources of imported and exported electricity;
- 3) Heat rates for the sources of imported and exported electricity; and
- 4) Carbon content coefficients of the fuels used to generate the imported and exported electricity.

The quantity of electricity imported and exported is the fundamental data on which the emission calculations are based. The sources of imported and exported electricity are needed to determine appropriate carbon content coefficients for the energy consumed. For example, the amount of carbon emitted during electricity production depends on the fuel source used to generate the electricity (*e.g.*, a coal, natural gas, or petroleum fired power plant). This data can be obtained from state or regional Public Utility Commissions (PUCs) or from individual utilities. At the national level, data on electric power generation and distribution is collected by EIA and reported in various documents including the *Electric Power Annual*.

The amount of electricity imported and exported will likely be reported in kilowatthours (kwh), while the typical carbon content factor is presented in mass of carbon released per unit of energy input (*e.g.*, lbs/MMBtu). Therefore, in order to determine the amount of carbon emitted during electricity generation, states must obtain the heat rates at the generating facilities concerned. The heat rate of a facility represents the amount of energy input required by a facility to produce a kilowatthour of electricity. Typical heat rates can vary from about 7,000 to 15,000 Btu/kwh, with a national average of approximately 10,000 Btu/kwh. This average is based on an EIA estimate that assumes approximately 67 percent of total energy input is lost during the conversion process (EIA, 1994e). This national average can be used as a default value, but it is recommended that states attempt to identify heat rates specific to their localities. Possible sources for such information are regional PUCs, individual utilities or independent power producers (IPPs).

After the fuel source has been determined and converted to energy units, the carbon content coefficients can be applied using the following equations:

$$EI_i = Imp_i \times HR_i \times CCC_i$$

$$EE_j = Exp_j \times HR_j \times CCC_j$$

where: EI = Emissions of carbon due to imports from source i (lbs carbon);
EE = Emissions of carbon due to exports from source j (lbs carbon);
Imp = Electricity imported from source i (kwh);
Exp = Electricity exported from source j (kwh);
HR = Heat Rates of generating facilities (Btu/kwh); and
CCC = Carbon Content Coefficients for source fuels (lbs carbon /Btu).

The carbon content coefficients used in these calculations are the same as those used in the rest of the energy emission calculations (see Tale D1-2). It should be noted that state-specific carbon content coefficients should be used if possible and that the source(s) of this information should be thoroughly documented.

Emissions calculated by the above equations should then be summed over all fuel sources and exported electricity emissions should be subtracted from imported electricity emissions:

$$NE = \sum EI_i - \sum EE_j$$

where: EI = Emissions of carbon due to imports from source i (lbs carbon);
EE = Emissions of carbon due to exports from source j (lbs carbon); and
NE = Net Emissions from interstate energy consumption (lbs carbon).

A negative number for net emissions indicates a net export of electricity, while a positive number indicates a net import of electricity. If emissions were distributed across end-use consumers, a net import would result in an increase in state emission totals, because it represents additional consumption attributable to end-users within the state. A net export would result in a decrease in state totals, because it represents fuel consumed in state to produce energy used by out of state consumers.

Estimate Carbon Oxidized during Combustion

As described earlier, not all carbon is oxidized immediately during the combustion of fossil fuels. The amount of carbon that falls into this category is usually a small fraction of total carbon, with a large portion of this carbon oxidizing in the atmosphere shortly after combustion. Based on Marland and Rotty (1984); Bechtel (1993); and other sources (EPA, 1994; IPCC\OECD, 1994), the following factors are recommended:

- For natural gas less than 0.5 percent of the carbon in natural gas is unoxidized during combustion and remains as soot in the burner, stack, or in the environment. (This is equivalent to a fraction oxidized of 0.995.)
- For petroleum fuels approximately 1 percent passes through the burners and is deposited in the environment without being oxidized. (This is equivalent to a fraction oxidized of 0.99.)
- For coal approximately 1 percent of carbon supplied to furnaces is discharged unoxidized, primarily as ash. (This is equivalent to a fraction oxidized of 0.99.)

These values vary based on fuel quality and technology types (particularly for coal). If more specific values are available for state level combustion, they should be used and clearly documented. In order to determine the amount of carbon actually oxidized and emitted, carbon sequestered in products and carbon emitted from interstate bunkers are subtracted from total potential emissions to obtain net potential emissions. These net emissions are then multiplied by the fraction of carbon oxidized to determine the amount of carbon oxidized from fuel combustion. This is represented in the following equation:

$$TOC_i = NPE_i \times FO_i$$

where: TOC_i = Total Oxidized Carbon for fuel i (lbs of carbon);

NPE_i = Net Potential Emissions for fuel i (lbs of carbon); and

FO_i = Fraction of carbon Oxidized for fuel i.

To obtain the total oxidized carbon for the state (or net carbon emissions from fossil fuel combustion), TOC_i is summed over all fuel types, excluding biomass fuels.

Summary

The previous calculations provide estimates of total carbon in the fossil fuels, carbon sequestered in non-energy products, and carbon emitted due to interstate energy consumption. Given these estimates, total carbon emissions from fossil fuel combustion can be determined. Total carbon emissions are equal to the total carbon content in fuel minus carbon sequestered in products and emissions from international bunkers, adjusted for the carbon unoxidized during combustion, and summed over all fuel types, excluding biomass fuels. Since the resulting figures are in units of carbon, they should be multiplied by 44/12 to obtain CO_2 on a full molecular weight basis (44/12 is the atomic mass ratio of CO_2 to carbon).

Data Sources

Statistics on energy and fossil-fuel production and consumption can be found in a number of sources, but inconsistencies often exist in how the data are presented, sources of the data, types of information provided, and reporting units. Information on production of products that sequester carbon also varies. EIA data could be used as a starting point, but states should use the energy data thought to be the most reliable (for example, from state energy commissions or PUCs). If states use in-state sources rather than EIA data, they are strongly urged to provide thorough documentation on the energy statistics, the reporting procedures, and definitions of sectoral activities. This would help to ensure consistency and comparability among all state estimates.

CO₂ EMISSIONS FROM THE CONSUMPTION OF BIOMASS-BASED FUELS

OVERVIEW

Biomass fuels (biofuels) such as wood and vegetal fuels are used for energy production, domestic cooking and heating, and industrial heat and power. Consumption of these fuels produces carbon dioxide, methane, carbon monoxide, nitrogen oxides, nitrous oxide, and non-methane volatile organic compounds. There are two phases of wood combustion that produce these trace gases: the flaming stage of combustion and the subsequent smoldering stage (Garrett, personal communication). During the flaming stage of combustion, which is usually violent and short-lived, oxygen is consumed as CO_2 is produced. In the smoldering phase, in which less oxygen is available, non- CO_2 substances are the primary products emitted.

An important distinction should be made between commercial and non-commercial biofuels consumption. Commercial consumers typically pay for the biofuels they consume in well-developed markets on which statistics are often available. Non-commercial consumers, however, typically collect their own fuelwood or purchase it from vendors. Lack of formal markets make it difficult to estimate the quantity of biomass consumed in this fashion. As a result, it may be difficult to estimate the *actual* amount of biofuels consumed because market statistics primarily reflect only commercial consumption. The extent of this problem will vary from state to state. In addition, limited data are available on the relative fuel properties of biofuels. In order to improve the quality of emission estimates from bioenergy consumption, additional research is needed to refine information on the total quantity of biomass consumed for energy purposes and the resulting emission factors under various combustion conditions.

It has been argued that CO₂ emissions resulting from bioenergy consumption should not be included in a state's official emissions inventory in order to avoid double counting CO₂ emissions. This double-counting would occur because: (1) biofuels tend to be produced on a sustainable basis such that no net increase in CO₂ occurs or (2) production of CO₂ from biofuels burned on a non-sustainable basis would be captured as part of emissions resulting from land-use changes (see Workbook and Discussion Section 10). Even though it is well understood that double-counting could occur, no solution is recommended at this time to assist analysts in resolving this matter and incorporating emissions from this source into overall CO₂ emissions. Therefore, it is currently recommended that states estimate and report CO₂ emissions from bioenergy consumption separately from CO₂ emissions from fossil fuel consumption, and that these emissions not be included in total state emissions. Thus, states should note that CO₂ emission estimates from biomass consumption do not currently represent a net increase in state CO₂ emissions, but that they are still calculated to ensure that all possible CO₂ emissions from energy consumption are estimated. The issue of double-counting CO₂ emissions from biofuels consumption should be given special attention in the near future to determine the most appropriate methods for accounting for these emissions.

DESCRIPTION OF WORKBOOK METHOD

The methodology for calculating CO₂ emissions from biomass is very similar to that used for fossil fuels. To estimate CO₂ emissions from biomass consumption, we need to determine biofuel consumption, carbon contents for the biofuels, and the fraction of fuel which is oxidized during combustion.

Wood consumption data should be reported in tons of dry matter and ethanol consumption should be reported in million Btu. Some conversion factors that may be used to obtain consumption in the proper units are given in Table D1-1.

The carbon content of wood, or the carbon in wood which could potentially be emitted, is simply the percent of total wood mass which is carbon. It is applied in a way similar to the carbon content coefficients used for ethanol and fossil fuel consumption, but it represents mass of carbon released per mass of fuel input, rather than carbon released per unit energy input (*e.g.*, percent of fuel mass rather than lbs carbon per Btu of energy). Table D1-4 contains carbon content assumptions used to estimate the percentage of each fuel type that is carbon.

The carbon potentially emitted must be adjusted for carbon that is not oxidized. Table D1-4 lists the default values for the fraction oxidized. It is assumed that 10 percent of all carbon in wood is not oxidized (Crutzen and Andreae, 1990). However, for purposes of this analysis, ethanol, is assigned a fraction oxidized of 0.99 due to its similarity to gasoline. These values could vary significantly based on fuel qualities and combustion processes and should be evaluated to determine their appropriateness.

Table D1-4: Carbon Content and Fraction Oxidized for Biofuel Consumption

<u>Fuel</u>	<u>Units of Consumption</u>	<u>Carbon Content</u>	<u>Fraction Oxidized</u>
Wood	tons dry matter	47.5%	0.90
Ethanol ¹	Btu	41.9 (lbs C / Btu)	0.99

¹ Since ethanol consumption is given in Btu, it has a carbon content coefficient rather than a carbon content. Its fraction oxidized is assumed to be about 0.99, since it is generally combusted in autos as a gasoline additive, and motor gasoline has a fraction oxidized of about 0.99.
Source: IPCC (1994) and Crutzen and Andreae (1990).

There are two basic equations for estimating CO₂ emissions from biofuel consumption. The first is used for wood and the second is used for ethanol.

$$(1) \quad E = C \times CC \times FO$$

$$(2) \quad EE = EC \times CCC \times FO$$

where: E = emissions (lbs carbon);

C = biofuel consumption (lbs fuel);

CC = carbon content (percent);

FO = fraction oxidized;

EE = emissions from ethanol (lbs carbon);

EC = ethanol consumption (Btu); and

CCC = carbon content coefficient (lbs carbon / Btu).

The resulting values indicate the amount of carbon dioxide that is emitted in pounds of carbon. To convert this value to full molecular weight of CO₂, these values should be multiplied by 44/12, which is the atomic mass ratio of CO₂ to carbon.

Data Availability

For ethanol production from biomass, state energy offices, economic development departments, agriculture departments, or revenue departments should have production figures. State energy or natural resource departments may also have data on the amount of wood collected for energy use, because permits are generally required to cut timber. EIA estimates national annual commercial biomass energy consumption in the U.S. for wood by sector and region and for ethanol by region (EIA, 1994c). The regions included in the EIA analysis are the South, the West, the Midwest, and the Northeast. No nationally compiled state-specific data are available in a published format.

The amount of energy produced from the biomass is difficult to estimate as it varies from one type of biomass to the next. Additional research will be needed to develop more precise consumption estimates, including the energy content of the biomass, in order to reduce uncertainties associated with calculating emissions. In addition to improving the quality of data on

commercial biomass consumption, research is needed to improve the quality of data on the non-commercial consumption of biomass.

Emissions from fuelwood also occur at different rates depending on the particular use of fuelwood since the technology used and the combustion conditions vary from one application to the next (*e.g.*, wood consumed in industrial wood boilers will emit at different emission rates than wood stoves for residential needs). Additional research will be needed to determine the range of technology types that consume fuelwood and to characterize the amount of fuelwood consumed by each technology type.²

UNCERTAINTIES

Carbon emissions occur from a number of activities associated with the production and transportation of energy, not all of which are accounted for in energy and non-energy uses of fossil fuels. These activities include gas venting and flaring, leakages during the transmission and distribution of natural gas, leakages during the transmission, distribution, and refining of oil, CH₄ emissions from coal mines, SO₂ scrubbing at coal plants, and burning in coal deposits. The first four of these activities - gas venting and flaring, leakages during the transmission and distribution of natural gas, leakages during the transmission, distribution, and refining of oil, and CH₄ leaks from coal mines - are addressed in Workbook and Discussion Sections 3 and 4. Emissions from the burning of coal in coal deposits and waste banks and CO₂ emissions from SO₂ scrubbing are highly variable from one state to another and are a very minor portion of total emissions. At this time, there is no recommended methodology to estimate emissions from these sources.

² Field measurements have yielded some data. See Cofer et al. (1988, 1989) and Hegg et al. (1990).

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DISCUSSION 2

GREENHOUSE GAS EMISSIONS FROM PRODUCTION PROCESSES

OVERVIEW

Emissions are often produced as a by-product of various non-energy related activities. That is, these emissions are produced directly from the process itself and are not a result of energy consumed during the process. For example, in the industrial sector raw materials are chemically transformed from one state to another. This transformation often results in the release of greenhouse gases such as carbon dioxide. The production processes presented in this section include: adipic acid production, carbon dioxide manufacture, cement production, lime production, limestone use (e.g., for iron and steel making, flue gas desulfurization, and glass manufacturing), nitric acid production, soda ash production and use, HCFC-22 production, and aluminum production. A section is also provided which lists other industrial source categories that potentially contribute to emissions of greenhouse gases. There are currently no available methodologies for estimating emissions from these sources.

DESCRIPTION OF WORKBOOK METHODS

In general, the basic method for estimating emissions from production processes is to gather information on the various activity levels required for the calculation (i.e., production and/or consumption data) and multiply them by their respective emission coefficients.

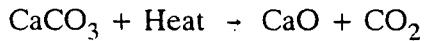
$$\text{Activity Level} \times \text{Emissions Factor} = \text{Amount Emitted}$$

In some instances, emission control or recovery technologies have been implemented at facilities which will reduce the amount of gas actually emitted. These avoided emissions should be accounted for by subtracting the amount recovered or avoided from emission totals.

The remainder of this section provides a description of each source category covered in Workbook Section 2 and a summary of how the emissions factors presented were derived. Information is also provided on the uncertainties associated with estimating emissions from each source category.

2.1 CARBON DIOXIDE EMISSIONS FROM CEMENT PRODUCTION

Carbon dioxide emitted during the cement production process represents the most significant non-energy source of industrial carbon dioxide emissions. Cement is produced in most states (and in Puerto Rico) and is used in all of them. Carbon dioxide is created when calcium carbonate (CaCO_3) is heated in a cement kiln to form lime (calcium oxide or CaO) and carbon dioxide. This process is known as *calcination* or *calcining*:



The lime is then combined with silica-containing materials (provided to the kiln as clays or shales) to form dicalcium or tricalcium silicates, two of the four major compounds in cement clinker (Griffin, 1987). This lime is combined with other materials to produce clinker (an intermediate product from which finished portland and masonry cement are made), while the carbon dioxide is released into the atmosphere.

Carbon dioxide emissions are estimated by applying an emission factor, in tons of CO₂ released per ton of clinker produced, to the total amount of clinker produced. The emission factor recommended for use by states is the product of the fraction of lime used in the cement clinker and a constant reflecting the mass of CO₂ released per unit of lime. The emission factor was calculated as follows:

$$EF_{clinker} = \text{fraction CaO} \times \left(\frac{44.01 \text{ g/mole } CO_2}{56.08 \text{ g/mole } CaO} \right)$$

This analysis assumes an average lime fraction for clinker of 64.6 percent, which yields an emission factor of 0.507 tons of carbon dioxide per ton of clinker produced.

Masonry cement requires additional lime over and above the lime used in the clinker. During the production of masonry cement, non-plasticizer additives such as lime, slag, and shale are added to the cement, increasing its weight by 5 percent. Lime accounts for approximately 60 percent of the added substances. An emission factor for this additional lime can be calculated as follows:

$$\begin{aligned} EF_{mas} &= \left(\frac{\text{fraction of weight added}}{1 + \text{fraction of weight added}} \right) \times \left(\frac{\text{fraction lime}}{\text{in added substance}} \right) \times \left(\frac{44.01 \text{ g/mole } CO_2}{56.08 \text{ g/mole } CaO} \right) \\ &= \left(\frac{0.05}{1 + 0.05} \right) \times 0.60 \times 0.785 \\ &= 0.0224 \end{aligned}$$

Thus, 0.0224 tons of additional carbon dioxide are emitted for every ton of masonry cement produced.

Some amount of CO₂ is reabsorbed when the cement is used for construction. As cement reacts with water, alkaline substances such as calcium hydroxide are formed. During the curing process, these compounds may react with CO₂ in the atmosphere to create calcium carbonate. This reaction only occurs in roughly the outer 0.2 inches of surface area. Since the amount of CO₂ reabsorbed is thought to be minimal, a methodology is not included here.

2.2 NITRIC ACID

The production of nitric acid (HNO₃) produces nitrous oxide (N₂O) as a by-product via the oxidation of ammonia. Nitric acid is a raw material used primarily to make synthetic commercial fertilizer. It is also a major component in the production of adipic acid (a feedstock for nylon) and explosives. In 1990, this inorganic chemical ranked thirteenth in total production of all chemicals in the United States. Relatively small quantities of nitric acid are employed for stainless steel pickling, metal etching, rocket propellants, and nuclear-fuel processing. Virtually all of the nitric acid produced in the U.S. is manufactured by the catalytic oxidation of ammonia (U.S. EPA, 1985).

During this reaction, nitrous oxide is formed as a by-product and is released from reactor vents into the atmosphere. While the waste gas stream may be cleaned of other pollutants such as nitrogen dioxide, there are currently no control measures aimed at eliminating nitrous oxide.

Nitric acid production in the U.S. was approximately 8 million tons in 1990. Off-gas measurements at one nitric acid production facility showed N₂O emission rates to be approximately 0.002 to 0.009 tons of N₂O per ton of nitric acid produced. It is therefore recommended that states use the midpoint of the range as the emissions factor to estimate emissions from this source: 0.0055 tons N₂O per ton of nitric acid produced.

The emission factors presented are highly uncertain because of insufficient information on manufacturing processes and emission controls. Although no abatement techniques are specifically directed at removing nitrous oxide, existing control measures for other pollutants will have some effect on the nitrous oxide contained in the gas stream. While the emission coefficients presented here do account for these other abatement systems, there may be some variation between different production facilities depending on the existing level of pollution control at a given plant.

2.3 ADIPIC ACID

Adipic acid is a white crystalline solid used in the manufacture of synthetic fibers, coatings, plastics, urethane foams, elastomers, and synthetic lubricants. Commercially, it is the most important of the aliphatic dicarboxylic acids, which are used to manufacture polyesters. Ninety percent of all adipic acid produced in the United States is used in the production of nylon 6,6, as well as production of some low-temperature lubricants. It is also used to provide foods with a "tangy" flavor. The U.S. accounts for approximately one-third of the total annual global production of adipic acid (Thiemens & Trogler, 1991).

Adipic acid is produced through a two-stage process. The second stage involves the oxidation of ketone-alcohol with nitric acid. Nitrous oxide is generated as a by-product of this reaction and enters the waste gas stream. In the U.S., this waste gas is treated to remove NO_x and other regulated pollutants (and, in some cases, N₂O as well) and is then released into the atmosphere. There are currently four plants in the U.S. that produce adipic acid. In 1990, two of these plants had emission control measures that destroyed about 98 percent of the nitrous oxide before it was released into the atmosphere (Radian, 1992). By 1996, all adipic acid production plants will have nitrous oxide emission controls in place as a result of a voluntary agreement among producers.

Since emissions of N₂O in the U.S. are not currently regulated, very little emissions data exist. However, based on the overall reaction stoichiometry for adipic acid, it is estimated that approximately 0.3 tons of nitrous oxide is generated for every ton of adipic acid produced (Radian, 1992). Because N₂O emissions are controlled in some adipic acid production facilities, the amount of N₂O that is actually released will depend on the level of emission controls in place at a specific production facility.

2.4 LIME MANUFACTURE

Lime is a manufactured product with many chemical, industrial, and environmental uses. In 1990, lime ranked fifth in total production of all chemicals in the United States. Its major uses are

in steelmaking, construction, pulp and paper manufacturing, and water and sewage treatment. Lime is manufactured by heating limestone (mostly calcium carbonate -- CaCO₃) in a kiln, creating calcium oxide (quicklime) and carbon dioxide. The carbon dioxide is driven off as a gas and is normally emitted to the atmosphere.

Lime is an important chemical with a variety of industrial, chemical, and environmental applications in the U.S. Lime production involves three main processes: stone preparation, calcination, and hydration. Carbon dioxide is generated during the calcination stage, when limestone (calcium carbonate or a combination of calcium and magnesium carbonate) or other calcium carbonate materials are roasted at high temperatures. This process is usually performed in either a rotary or vertical kiln, although there are a few other miscellaneous designs. Carbon dioxide is produced as a by-product of this process, just as CO₂ is released during clinker production (see previous section on cement production). The carbon dioxide is driven off as a gas and normally exits the system with the stack gas. The mass of CO₂ released per unit of lime produced can be calculated based on their molecular weights:

$$44.01 \text{ g/mole CO}_2 \div 56.08 \text{ g/mole CaO} = 0.785$$

Therefore, an emissions factor of 0.785 tons of CO₂ per ton of lime manufactured is recommended for use by states.

The term "lime" is actually a general term that includes various chemical and physical forms of this commodity. Uncertainties in emission estimates can be attributed to slight differences in the chemical composition of these products. For example, although much care is taken to avoid contamination during the production process, lime typically contains trace amounts of impurities 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 manufacture lime with exactly the same properties.

A portion of the carbon dioxide emitted during lime production will actually be reabsorbed when the lime is consumed. In most processes that use lime (*e.g.*, water softening), carbon dioxide reacts with the lime to create calcium carbonate. This is not necessarily true about lime consumption in the steel industry, however, which is the largest consumer of lime. A detailed accounting of lime use in the U.S. and further research into the associated processes are required to quantify the amount of carbon dioxide that will be reabsorbed.

2.5 LIMESTONE USE

Limestone is a basic raw material used by a wide variety of industries, including the construction, agriculture, chemical, and metallurgical industries. For example, limestone can be used as a flux or purifier in refining metals such as iron. In this case, limestone heated in a blast furnace reacts with impurities in the iron ore and fuels, generating carbon dioxide as a by-product. Limestone is also used for glass manufacturing and for SO₂ removal from stack gases in utility and industrial plants.

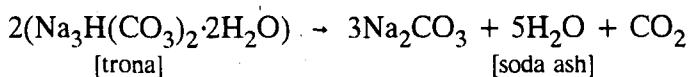
Limestone is heated during these processes, generating carbon dioxide as a by-product. Carbon emissions can be calculated by multiplying the amount of limestone consumed by type (*i.e.*, calcite or dolomite) by the carbon content of the limestone. Therefore, emissions factors

recommended for use by states are 0.12 tons C per ton of limestone (or calcite) consumed and 0.13 tons C per ton of dolomite consumed.¹ Estimates are then multiplied by 44/12 to obtain the amount of carbon emitted as CO₂.

Uncertainties in estimates calculated using this method can be attributed to variations in the chemical composition of limestone. In addition to calcite, limestone may contain smaller amounts of magnesia, silica, and sulfur. The exact specifications for limestone or dolomite used as flux stone vary with the pyrometallurgical process, the kind of ore processed, and the final use of the slag. Similarly, the quality of the limestone used for glass manufacturing will depend on the type of glass being manufactured. Uncertainties also exist in the activity data. Much of the limestone consumed in the U.S. is reported as "other unspecified uses", and therefore, are difficult to disaggregate by type.

2.6 SODA ASH CONSUMPTION AND MANUFACTURE

Commercial soda ash (sodium carbonate) is used in many familiar consumer products such as glass, soap and detergents, paper, textiles, and food. About 75 percent of world production is synthetic ash made from sodium chloride; the remaining 25 percent is produced from natural sources. The U.S. produces only natural soda ash. During the production process, trona (the principal ore from which natural soda ash is made) is calcined in a rotary kiln and chemically transformed into a crude soda ash that requires further processing. Carbon dioxide and water are generated as a by-product of the calcination process. CO₂ emissions from the calcination of trona can be estimated based on the following chemical reaction:



Based on this formula, it takes approximately 10.27 tons of trona to generate 1 ton of CO₂, or 0.0974 tons of CO₂ per ton of trona produced.

An alternative method of natural soda ash production uses sodium carbonate-bearing brines. To extract the sodium carbonate, the complex brines are first treated with carbon dioxide in carbonation towers to convert the sodium carbonate into sodium bicarbonate, which will precipitate under these conditions. The precipitated sodium bicarbonate is then calcined back into sodium carbonate. Although CO₂ is generated as a by-product, the CO₂ is recovered and recycled for use in the carbonation stage and is never actually released.

Carbon dioxide is also released when soda ash is consumed. Glass manufacture represents about 49 percent of domestic soda ash consumption, with smaller amounts used for chemical manufacture, soap and detergents, flue gas desulfurization, and other miscellaneous uses. In each of these applications, a mole of carbon is released for every mole of soda ash used. Thus, approximately 0.113 tons of carbon is released for every ton of soda ash consumed, or 0.415 tons of CO₂ per ton of soda ash consumed.

¹ Limestone (CaCO₃) and dolomite (CaMg(CO₃)₂) are collectively referred to as limestone by the industry, and intermediate varieties are seldom distinguished.

2.7 CARBON DIOXIDE MANUFACTURE

Carbon dioxide is used for a variety of industrial and miscellaneous applications, including food processing, chemical production, carbonated beverages, and enhanced oil recovery. Carbon dioxide used for enhanced oil recovery is injected into the ground to increase reservoir pressure, and is therefore considered sequestered². For the most part, however, carbon dioxide used in these applications will eventually enter the atmosphere.

With the exception of a few natural wells, carbon dioxide is produced as a by-product from the production of other chemicals (*e.g.*, ammonia), or obtained by separation from crude oil or natural gas. Depending on the raw materials that are used, the by-product carbon dioxide generated during these production processes may already be accounted for in the CO₂ emission estimates from fossil fuel consumption (either during combustion or from non-fuel use). For example, ammonia is manufactured using natural gas and naphtha as feedstocks. Carbon dioxide emissions from this process are included in the portion of carbon for non-fuel use that is not sequestered (see Workbook and Discussion Section 1).

Carbon dioxide emissions are calculated by estimating the fraction of manufactured carbon dioxide that is not accounted for in these other emission sources and multiplying it by a recommended emissions factor of 1 ton of CO₂ per ton of CO₂ manufactured. It is assumed that 100 percent of CO₂ manufactured for these other uses is eventually released to the atmosphere.

2.8 EMISSIONS OF PERFLUORINATED CARBONS (PFCs) AND CO₂ FROM ALUMINUM SMELTING

The aluminum production industry is thought to be the largest source of two PFCs -- CF₄ and C₂F₆. Emissions of these two potent greenhouse gases occur during the reduction of alumina in the primary smelting process.³ Aluminum is produced by the electrolytic reduction of alumina (Al₂O₃) in the Hall-Heroult reduction process, whereby alumina is dissolved in molten cryolite (Na₃AlF₆), which acts as the electrolyte and is the reaction medium. PFCs are formed during disruptions of the production process known as anode effects (AE), which are characterized by a sharp rise in voltage across the production vessel. The PFCs can be produced through two mechanisms: direct reaction of fluorine with the carbon anode; and electrochemical formation. In both cases the fluorine originates from dissociation of the molten cryolite.

Because CF₄ and C₂F₆ are inert, and therefore pose no health or local environmental problems, there has been little study of the processes by which emissions occur and the important factors controlling the magnitude of emissions. In general, however, the magnitude of emissions for a given level of production depends on the frequency and duration of the anode effects during that production period. The more frequent and long-lasting the anode effects, the greater the emissions.

² It is unclear to what extent the CO₂ used for enhanced oil recovery will be re-released. For example, the carbon dioxide used for EOR is likely to show up at the wellhead after a few years of injection (Hangebrauk et al., 1992). This CO₂, however, is typically recovered and reinjected into the well. More research is required to determine the amount of carbon dioxide that may potentially escape. For the purposes of this analysis, it is assumed that all of the CO₂ remains sequestered.

³ Perfluorinated carbons are not emitted during the smelting of recycled aluminum.

The methodology used to estimate emissions of PFCs from aluminum production first calculates a per unit production emissions factor as a function of several important operating variables, including average anode effect frequency and duration. Total annual emissions are then calculated based on reported annual production levels. The five components of the per unit production emissions factor are:

- the amount of CF_4 and C_2F_6 emitted during every minute of an anode effect, per kAmp of current;
- the average duration of anode effects, expressed in anode effect minutes per effect;
- the average frequency of anode effects, expressed in anode effects per day;
- the current efficiency for aluminum smelting (no units); and,
- the current required to produce a metric ton of aluminum, assuming 100 percent efficiency.

Using currently available data for the U.S., this methodology yields a range in the emissions factor of 0.0003 to 0.0009 tons CF_4 per ton of aluminum produced (with a midpoint of 0.0006 tons CF_4 per ton of aluminum produced) (U.S. EPA, 1993). The emissions factor for C_2F_6 is estimated to be an order of magnitude lower, and therefore ranges from 0.00003 to 0.00009 ton C_2F_6 per ton of aluminum produced (with a midpoint of 0.00006 tons C_2F_6 per ton of aluminum produced).

Because there has been relatively little study of emissions from this source, considerable uncertainty remains in the emissions factors presented here. In particular, the value for emissions per AE minute per kAmp is based on a single measurement study which may not be representative of the industry as a whole (U.S. EPA, 1993). For example, this emissions factor may vary by smelter technology type, among other factors. The average duration of anode effects, according to preliminary results of ongoing research, may in fact be considerably shorter than the current values used. The average frequency of anode effects and the current efficiency are well documented, although they may change over time as operating efficiencies improve. Because recent studies indicate that the values for the important variables used in developing the emission coefficient may actually be lower than previously thought, the estimates calculated using these emission factors are likely to be conservatively high.

Carbon dioxide is also emitted during the aluminum production process when alumina (aluminum oxide) is reduced to aluminum. The reduction of the alumina occurs through electrolysis in a molten bath of natural or synthetic cryolite. The reduction cells contain a carbon lining that serves as the cathode. Carbon is also contained in the anode, which can be a carbon mass of paste, coke briquettes, or prebaked carbon blocks. During reduction, some of this carbon is oxidized and released to the atmosphere as carbon dioxide. Approximately 1.5 to 2.2 tons of CO_2 are emitted for each ton of aluminum produced (Abrahamson, 1992). The CO_2 emissions from this source, however, are already accounted for in the non-fuel use portion of CO_2 emissions from fossil fuel consumption, which was estimated in Workbook Section 1 (*i.e.*, the carbon contained in the anode is considered a non-fuel use of petroleum coke). Thus, to avoid double-counting, CO_2 emissions from aluminum production should not be included the industrial process emission totals.

2.9 EMISSIONS OF PARTIALLY HALOGENATED COMPOUNDS (HFCs)

HFCs are chemicals containing hydrogen, carbon, and fluorine. Only recently have they been produced on a large scale. As some of the primary alternatives to the ozone depleting substances

(ODSs) being phased out under the *Montreal Protocol* and subsequent amendments, the use of HFCs is expected to increase in the future. Sources of HFC emissions can be categorized as follows:

- Emissions as by-products of chemical production processes, and
- Emissions of HFCs used as substitutes for ODSs in refrigeration, foam blowing, solvent, aerosol, and fire extinguishing applications.

The only type of HFC known to be emitted in significant quantities, at present, is HFC-23 emitted as a by-product of HCFC-22 production. Therefore, a methodology for estimating emissions of HFCs as an ODS replacement is not presented at this time.

HFC-23 as a By-Product

The suggested methodology for estimating emissions from this source is to obtain estimates of HCFC-22 production from in-state chemical manufacturers and multiply this production by 0.04 tons of HFC-23 per ton of HCFC-22 produced. The factor of 0.04 tons HFC-23/ton HCFC-22 produced was chosen because it is assumed that, in general, by-product emissions of HFC-23 are assumed to be 4 percent of HCFC-22 production. However, using this emissions factor may overestimate emissions, because at some production facilities, emission control measures may have been implemented that can halve by-product emissions of HFC-23. States should enquire about emission control devices at individual production facilities to increase the accuracy of their estimates.

2.10 EMISSIONS FROM OTHER PRODUCTION PROCESSES

Several processes that produce greenhouse gas emissions are listed in Table D2-1. This is not a definitive list since other activities do generate process emissions, although the major processes are identified here. Each state may have additional categories that need to be identified in the future. There are currently no recommended emission estimation methodologies for these sources.

Table D2-1
Emissions From Production Processes

PROCESS	POLLUTANTS					
	NO _x	NM VOC	CH ₄	CO	CO ₂	N ₂ O
Agricultural Liming					X	
Ferro-alloy Production					X	
Silisium Carbid Production					X	
Coke Production				X	X	
Nitrogen Fertilizer Production	X					

PROCESS	POLLUTANTS					
	NO _x	NM VOC	CH ₄	CO	CO ₂	N ₂ O
Petroleum Product Processing (including FOC)	X	X	X	X	X	X
Sulphur Recovery Plants						
Storage of Petroleum Products in a Refinery		X				
Colliery Coke Production		X	X			
Metallurgical Coke Production		X	X			
Steel Plant (electric, BOF, etc.)	X		X	X	X	
Sulfuric Acid Production						
Ammonia Production		X	X			
Sodium Carbonate						
Urea Production						
Carbon Black		X				
Titanium Dioxide						
Ethylene Production	X					X
Propylene Production		X				
1,2 Dichloroethane Production		X				
Vinylchloride Production		X				
Polyethylene Low Density Production		X				
Polyethylene High Density Production		X				
Polyvinylchloride Production		X				

PROCESS	POLLUTANTS					
	NO _x	NM VOC	CH ₄	CO	CO ₂	N ₂ O
Polypropylene Production		X				
Styrene Butadiene		X				
ABS Resins		X				
Ethylene Oxide		X				
Formaldehyde Production		X				
Ethylbenzene Production		X				
Styrene Butadiene Latex		X				
Styrene Butadiene Rubber		X				
Phtalic Anhydride Production		X				
Acrylonitrile Production		X			X	
Chipboard Production		X				
Paper Pulp Production		X				
Bread Production		X			X	
Wine Production		X			X	
Beer Production		X			X	
Spirits Production		X			X	
Paint Applications: manufacture of automobiles		X				
Paint Applications: ship building		X				
Paint Applications: manufactures of metal articles		X				

PROCESS	POLLUTANTS					
	NO _x	NM VOC	CH ₄	CO	CO ₂	N ₂ O
Paint Applications: wood products		X				
Paint Applications: construction and buildings		X				
Paint Applications: vehicles refinishing		X				
Paint Applications: domestic use		X				
Metal Degreasing		X				
Dry Cleaning		X				
Polymers Processing		X				
Elastomers Processing		X				
Rubber Processing		X				
Plastics Processing		X				
Pharmaceutical Processing		X				
Paints Processing		X				
Inks Processing		X				
Glues Processing		X				
Printing Industry (solvent use only)		X				
Domestic Solvent Use		X				

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DISCUSSION 3

METHANE EMISSIONS FROM NATURAL GAS AND OIL SYSTEMS

OVERVIEW

Emissions from natural gas and oil systems are primarily methane, although smaller quantities of non-methane VOCs, carbon dioxide, and carbon monoxide can be emitted. It is important to account for emissions from oil and natural gas systems separately in order to differentiate between emissions associated with particular fuels. For purposes of the workbook, the terms natural gas or gas are used to refer to both natural gas (extracted from the ground), and "synthetic" or "substitute" natural gas (comprised mostly of methane) produced from other petroleum-based products or sources. Depending on its origin and how it is processed, commercially distributed natural gas also will include various amounts of non-methane hydrocarbons (*e.g.*, ethane, butane, propane, and pentane), carbon monoxide, carbon dioxide, and nitrogen. Oil is used to refer to both oil extracted directly from the ground and various synthetic processes such as oil shale or tar sands.

Methane is emitted during oil and gas production, storage, transportation and distribution. "Fugitive" sources of emissions within oil and gas systems include: releases during normal operations, such as emissions associated with venting and flaring during oil and gas production, chronic leaks or discharges from process vents; emissions during routine maintenance, such as pipeline repair; and emissions during system upsets and accidents.

Oil and Natural Gas System Overview: Oil and gas systems are divided into three main parts for this discussion:

1. **Oil and Gas Production:** Oil and gas are withdrawn from underground formations using on-shore and off-shore wells. Oil and gas are frequently withdrawn simultaneously from the same geologic formation, and then separated. Gathering lines are generally used to bring the crude oil and raw gas to one or more collection point(s) within a production field. Because methane is the major component of natural gas, leaks or venting from these systems result in methane emissions.
2. **Crude Oil Transportation and Refining:** Crude oil is transported by pipeline to tankers and refineries. Often, the crude oil is stored in tanks for a period of time. Methane is usually found in the crude oil stream, and leaks or venting of vapors from these facilities result in methane emissions, particularly from crude oil tankering. Methane emissions from crude oil streams are strongly dependent on the original methane content of the crude oil and its preparation for transport.

Refineries process crude oil into a variety of hydrocarbon products such as gasoline and kerosene. During the refining process, methane and other hydrocarbons are separated and methane may be leaked or vented in some processes. Refinery outputs, referred to as "refined products," generally contain negligible amounts of methane. Consequently, methane emissions are not estimated for transporting and distributing refined products.

3. **Natural Gas Processing, Transportation, and Distribution:** Natural gas is processed to recover heavier hydrocarbons, such as ethane, propane and butane, and prepare the dried gas for transporting to consumers. Most gas is transported through transmission and distribution pipelines. A small amount of gas is shipped by tanker as liquefied natural gas (LNG). Because only a small portion of gas is transported as LNG, emissions from LNG facilities are not included in this discussion.

The following are the main processing, transportation, and distribution activities:

- **Gas processing plants:** Natural gas is usually processed in gas plants to produce products with specific characteristics. Depending on the composition of the unprocessed gas, it is dried and a variety of processes may be used to remove most of the heavier hydrocarbons, or condensate, from the gas. Processed gas is then injected into the natural gas transmission system and the heavier hydrocarbons are marketed separately. Unintentional leaks of methane occur during natural gas processing.
- **Transmission pipelines:** Transmission facilities are high pressure lines that transport gas from production fields, processing plants, storage facilities, and other sources of supply over long distances to distribution centers, or large volume customers. Although transmission lines are usually buried, a variety of above underground facilities support the overall system including metering stations, maintenance facilities, and compressor stations located along pipeline routes.

Compressor stations, which maintain the pressure in the pipeline, generally include upstream scrubbers where the incoming gas is cleaned of particles and liquids before entering the compressors. Reciprocating engines and turbines are used to drive the compressors. Compressor stations normally use pipeline gas to fuel the compressor. They also use the gas to fuel electric power generators to meet the station's electricity requirements.

- **Distribution systems:** Distribution pipelines are extensive networks of generally small diameter, low pressure pipelines. Gas enters distribution networks from transmission systems, known as "gate stations", where the pressure is reduced for distribution within cities or towns.

Sources of Methane Emissions in the Oil and Natural Gas Systems: Emissions from oil and gas systems can be categorized into: (1) emissions during normal operations (2) routine maintenance; and (3) system upsets and accidents. In Table D3-1 these emission types are linked to the different stages in oil and gas systems. Typically the majority of the emissions are from normal operations.

1. **Normal Operations:** Normal operations are the day-to-day operations of a facility absent of occurrence of abnormal conditions. Emissions from normal operations can be divided into two main source categories: (1) venting and flaring and (2) discharges from process vents, chronic leaks, etc.

Venting and Flaring - Venting and flaring refers to the disposal of the gas that cannot be contained or otherwise handled. Such venting and flaring activities are associated with combined oil and gas production and take place in production areas where gas and pipeline infrastructure is incomplete and the natural gas is not injected into reservoirs.

Table D3-1. Emissions from Oil and Natural Gas Systems

Segment	Major Emissions Sources	Other Potential Emission Sources
Oil and Gas Production Oil and gas wells Gathering lines Treatment facilities	Venting Normal operation: fugitive emissions; deliberate releases from pneumatic devices and process vents.	Flare and combustion in gas turbines, IC engines, etc. Routine maintenance System upsets and accidents
Crude Oil Transportation and Refining Pipelines Tankers Storage tanks Refineries	Normal operations: fugitive emissions; deliberate releases from process vents at refineries, during loading and unloading of tankers and storage tanks.	Combustion in gas turbines, IC engines, etc. Routine maintenance System upsets and accidents
Natural Gas Processing, Transportation, and Distribution Gas plants Underground storage reservoirs Transmission Pipelines Distribution pipelines	Normal operations: fugitive emissions; deliberate releases from pneumatic devices and process vents.	Combustion in gas turbines, IC engines, etc. Routine maintenance System upsets and accidents

Source: IPCC, 1994

Venting activities release methane because vented gas typically has a high methane content. If the excess gas is burned in flares, the emissions of methane will depend on how efficient the burning processes are. Generally, the combustion efficiency for flare sources are assumed to be between 95 and 100 percent. To estimate the methane emissions from venting and flaring activities satisfactorily, it is required to know the flare efficiency rates and the distributed quantity of gas vented and gas flared.

Discharges from Process Vents, Chronic Leaks, etc. - Methane emissions will also occur when gas pipeline infrastructure is available and the market for natural gas is well developed. Oil and gas production, gas processing, oil and gas transportation and gas distribution facilities emit methane due to a wide variety of operating practices and factors, including:

- Emissions from pneumatic devices (gas-operated controls such as valves and actuators). These emissions depend on the size, type, and age of the devices, the frequency of their operation, and the quality of their maintenance.
- Leaks from system components. These emissions are unintentional and typically consist of continuous releases associated with leaks from the failure of a seal or the development of a flaw, crack or hole in a component designed to contain or convey oil or gas. Connections, valves, flanges, instruments, and compressor shafts can develop leaks from cracks or from corrosion.

- Emissions from process vents, such as vents on glycol dehydrators and vents on crude oil tankers and storage tanks. Vapors, including methane, are emitted from the vents as part of the normal operation of the facilities. However, such process vents are minor methane sources in most gas production facilities.
 - Emissions from starting and stopping reciprocating engines and turbines.
 - Emissions during drilling activities, *e.g.*, gas migration from reservoirs through wells.
2. **Routine Maintenance:** Routine maintenance includes regular and periodic activities performed in the operation of the facility. These activities may be conducted frequently, such as launching and receiving scrapers (pigs) in a pipeline, or infrequently, such as evacuation of pipes ("blowdown") for periodic testing or repair. In each case, the required procedures release gas from the affected equipment. Releases also occur during maintenance of wells ("well workovers") and during replacement or maintenance of fittings.
3. **System Upsets and Accidents:** Systems upsets are unplanned events in the system, most common of which is a sudden pressure surge resulting from the failure of a pressure regulator. The potential for unplanned pressure surges is considered during facility design, and facilities are provided with pressure relief systems to protect the equipment from damage due to the increased pressure.

Release systems vary in design. In some cases, gases released through relief valves may be collected and transported to a flare for combustion or re-compressed and reinjected into the system. In these cases, methane emissions associated with pressure relief events will be small. In older facilities, relief systems may vent gases directly into the atmosphere or send gases to flare systems where complete combustion may not be achieved.

The frequency of system upsets varies with the facility design and the operating practices. In particular, facilities operating well below capacity are less likely to experience system upsets and related emissions. Emissions associated with accidents are also included in the category of upsets. Occasionally, gas transmission and distribution pipelines are accidentally ruptured by construction equipment or other activities. These ruptures not only result in methane emissions, but they can be extremely hazardous as well.

Table D3-1 lists those emissions types that are the most important sources within each segment of the oil and gas industry. Based on available information, the sources listed as "major" account for the majority of emissions from each segment. Because our data are limited and there is considerable diversity among oil and gas systems throughout the U.S., other potential sources are also listed which may, in some cases, be important contributors to emissions.

DESCRIPTION OF WORKBOOK METHOD

The method presented in the Workbook Section is essentially one in which standard emissions factors are multiplied by activity data that describe the oil and gas system size or capacity. While it is relatively easy to obtain the necessary activity data, it should be noted that the basis for developing the emissions factors is very weak at this time. Because oil and natural gas systems are comprised of a complex set of facilities, simple relationships between emissions and components of the systems are not easily defined. Additionally, no single set of emissions factors can apply to all conditions.

Consequently, more detailed assessments are required to reflect the diverse nature of the industry throughout the U.S.

The emissions factors presented in the Workbook Section were developed as part of the IPCC emissions inventory guidelines for oil and gas systems (IPCC, 1994). The emissions factors were developed based on a review of all available published estimates of methane emissions from the various sectors of the oil and gas industry. Although the objective in developing the emissions factors was to include all emissions sources and types (described in the previous section), in some cases no published emissions estimates were found for categories of emissions believed to be negligible.

Using the available published emissions estimates, the implied emissions factors from each study were developed by dividing the emissions estimates by appropriate measures of system size or capacity in energy units. Across the studies, the resulting implied emissions factors per unit of energy showed a wide range. The estimates were grouped by region, and within each region a range of emissions factors was selected for the IPCC emissions inventory guidelines. The emissions factors used in the Workbook Section are the factors developed from studies of the U.S. system.

The emissions factors can be considered to be no better than "order of magnitude" estimates. Actual emissions depend on site specific characteristics including:

- facility design;
- facility operation; and
- facility maintenance.

While these characteristics were considered to various extents in the studies that formed the basis for the emissions factor estimates, the variation in characteristics among systems throughout the U.S. implies that no single set of emissions factors can be adequate for estimating emissions.

ALTERNATE METHODOLOGIES

To estimate emissions from oil and gas systems, it would be preferred to measure emissions with precise instruments. However, due to the diverse nature of the various types of emissions and the fact that many emissions occur periodically or unexpectedly, precise measurements are not practical in most cases. Additionally, no single method for estimating emissions will be appropriate for all the different types of emissions. Although much of the information required to estimate emissions from oil and gas systems is not readily-available at this time, the data may be available for the U.S. or will shortly be available from ongoing work. A minimum data set should be established separately for oil and natural gas systems based on this information to estimate the various types of emissions from the different system components identified above. These two minimum data sets are summarized in Table D3-2.

The data sets summarized in Table D3-2 indicate the minimum amount of activity data needed to estimate emissions. For each of the data items, an emission factor(s) would need to be developed. To assist in the development of appropriate emission factors, emission data are currently being generated by the Gas Research Institute (GRI) and EPA. These could be used to develop the range of emission factors for the activity data identified in Table D3-2. Information about the systems examined in the detailed studies would need to be assembled, described, compared, and contrasted so

that states could identify pieces of these systems that are similar to theirs and select appropriate emissions factors.

In addition to the GRI/EPA study, there are other approaches that could be employed to determine oil and natural gas system emissions. The following section discusses the range of methods identified and the types of emissions for which they may be useful; the discussion focuses primarily on applications for natural gas systems. These more complex approaches could be used for refining emission estimates derived from the minimum methodology.

Gas Accounting Data

Gas accounting data are routinely developed during the operation of gas systems. These data describe the quantities of gas that are produced, transported, injected, withdrawn, used, or sold at various stages. Various instrumentation is used to measure pressure, temperatures, and flow rates to develop these accounting data.

Gas accounting data can be very useful for estimating emissions associated with routine maintenance activities. The quantities of gas released during these activities are often estimated and recorded using standardized procedures. For example, these data can be used to estimate gas that is released during scheduled repair of transmission pipelines.

Routinely collected accounting data are often not adequate for estimating fugitive emissions from production and distribution facilities (*i.e.*, leaks from pipes and equipment). These emissions are usually too small to be estimated because the meters and instruments used to measure gas flows are not adequately precise to measure the small leaks that are generally encountered. Additionally, other factors that are not well quantified (such as theft) reduce the precision of the routinely-collected gas accounting data.

Unlike routinely-collected accounting data, specially conducted measurement studies using specially-designed and operated meters and instruments may be useful for estimating fugitive emissions from designated sections of distribution systems. In conducting such studies, care must be taken to ensure that the segments of distribution systems that are studied are representative of the overall distribution system.

Emission Factors

Emission factors provide estimates of emissions for specific types of equipment over specified periods of time, such as 0.1 cubic meter (m^3) per hour from a given type of valve. Emission factors are most commonly used to estimate fugitive emissions from equipment. The most important consideration in using emission factors is that care must be taken to ensure that the emission factors are appropriate for the type of equipment in question, including the maintenance practices that are performed. As described below there are several major sources of emission factors for the types of equipment commonly found in gas production fields and gas processing plants. To use the emission factors, the numbers of components of various types are multiplied by the emission factors specific to those types. The aggregate is an estimate of the total emissions.

Procedures have been developed to estimate emission factors quantitatively (Radian 1982). These procedures generally require that:

Table D3-2
Minimum Data Sets for Oil and Natural Gas Systems^a

<i>Oil System Data Set</i>		
<u>System Component</u>	<u>Activity Data Needed</u>	<u>Emission Factor</u>
Pre-production	Number of successfully drilled wells	To be determined
Production and Central Processing	Number of operating wells Level of oil production Composition of the oil Type of emission controls	To be determined To be determined To be determined To be determined
Venting and Flaring	Flaring losses	To be determined
Transportation	Composition of the oil Quantity of oil transported by ocean tanker or large pipeline	To be determined To be determined
Distribution	Quantity of oil distributed	To be determined

<i>Natural Gas System Data Set</i>		
<u>System Component</u>	<u>Activity Data Needed</u>	
Pre-production	Number of successfully drilled wells	To be determined
Production and Central Processing	Number of operating wells Quantity of natural gas produced Composition of the natural gas Type of emission controls	To be determined To be determined To be determined To be determined
Venting and Flaring	Flaring losses	To be determined
Transmission	Composition of the gas (% methane) Length of transmission piping	To be determined To be determined
Distribution	Length of pipe designed by pipe type	To be determined

^a For each system component, the activity data level would be multiplied by the appropriate emission factor to determine emissions for that component.

- the numbers of each type of component be counted (e.g., the number of valves, etc.);
- a sample of components be selected randomly (this selection is often stratified using an indication of the leak rate);
- the actual emission rates (e.g., in m³ per hour) from the individual components selected are measured;
- the measurements are used to develop emission factors that consider the different component types and represent the weighting of the strata; and
- the emission factors are applied to the total number of components identified.

The advantage of developing emission factors is that the approach reflects the condition of equipment and maintenance practices at specific facilities and is based on actual physical measurements and reliable statistical techniques. The drawback of the approach is that it can be costly and can produce estimates that have a wide range of uncertainty associated with them. Currently, U.S. EPA and GRI are developing a system that will attempt to quantify uncertainty, especially for sources where emissions and uncertainty appear to be high.

Emission factors can also be used to estimate emissions from instruments powered by compressed gas. The number of various types of instruments must be obtained, and the emissions associated with the use of each type must be estimated or obtained from manufacturers.

Leak Repair Data

Leak detection and repair programs generally produce data on the number of various types of leaks detected and repaired in distribution systems. Unfortunately, the quantity of gas emitted from individual leaks is generally not available. Therefore, based on the data that are usually collected, emissions from line leaks are not quantifiable.

Activity Studies

Total emissions can also be estimated by multiplying the amount emitted during an activity by the number of times the activity occurs per year. For example, the emissions associated with starting a compressor or scraping a given length of pipeline can be estimated based on the procedures used. The frequency with which these activities are undertaken for, say, a typical compressor station, can then be estimated based on operating records, *i.e.*, total emissions from this source is equal to the emissions per occurrence times the number of occurrences per year.

All the methods described here must consider the portion of the gas that is actually methane. Additionally, all estimates must be careful to consider and report the temperatures and pressures at which the volumes are estimated. All estimates should therefore be reported on a mass basis (*e.g.*, in tons) as well as a volume basis.

DATA SOURCES

No individual data source will provide all the information needed to estimate emissions from oil and gas systems. Several studies have been undertaken that use one or more of the techniques described above including: Cowgill and Waller (1990), PSI (1989), PSI (1990), INGAA (1989), AGA (1989), Barns and Edmonds (1990), Radian (1982), Rockwell (1980), Lillie (1989), ADL (1989), Schneider-Fresenius *et al.* (1989), and Thorell + VBB (1989). These studies are instructive regarding the manner in which emissions can be estimated and the uncertainties inherent in the exercise.

Radian (1982) and Rockwell (1980) both involve the development and application of emissions factors for estimating fugitive emissions. EPA (1985) has a summary of emissions factors for various types of equipment, including compressors. Detailed emissions data from equipment that can contribute to the development of emissions factors have been collected and reported in a variety of studies including: Martin and Thring (1989), Leslie *et al.* (1989), and EPA (1979).

The studies by PSI (1989 and 1990) include assessments of activity levels and emissions per activity occurrence. Cowgill and Waller (1990) offers the most detailed and complete analysis of the fate of gas in a system. This study goes into considerable depth in applying a wide variety of the approaches discussed above.

In addition to these various emissions-related studies, gas companies and agencies responsible for gas safety and operations are important sources of data. Finally, McAllister (1988) is a useful source of methods for estimating gas flows under various circumstances.

UNCERTAINTIES

The ability to estimate emissions from oil and gas systems will be hampered by the general lack of data on the factors that lead to emissions. These systems are very diverse and variable. Emissions generally cannot be estimated with simple assumptions or rules of thumb. Nevertheless, recent studies indicate that the main types of emissions can be assessed with fairly straightforward approaches.

The most difficult emissions to estimate will likely be fugitive emissions from distribution systems. The precision of gas accounting data is typically not adequate enough to estimate emissions from these sources. Because these emissions can be quite important, specially-conducted measurement studies using specially-designed and operated meters and instruments may be required. Such studies would improve considerably the basis for estimating emissions from this source.

Additional observations have been offered, including:

- Emissions from fuel used in compressor stations and related equipment for providing the pressure to transport the fuel over land were not included in the fuel production category but part of the stationary combustion category. Each state should ensure that the energy consumed for these activities is accounted for accordingly.
- More information is needed on non-methane VOC emission factors.

- CO₂ emissions from certain gas and oil fields could be significant but are not well characterized. Additional effort is needed to understand these emissions.
- The factors for methane emitted during incomplete combustion should be reviewed.
- Sources of information for obtaining the data outlined above need to be investigated in greater detail.

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DISCUSSION 4

METHANE EMISSIONS FROM COAL MINING

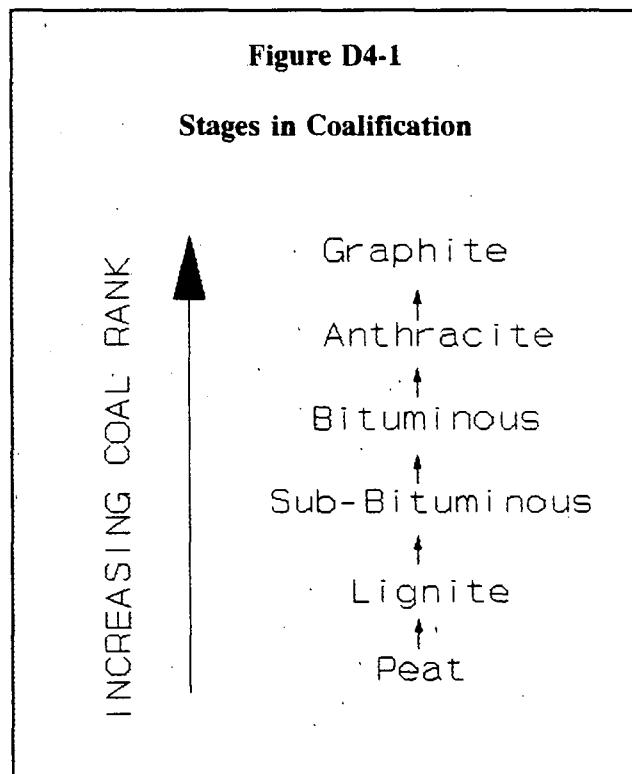
OVERVIEW¹

Methane emissions from coal mines are heavily dependent on the geological characteristics and history of the coalbed. Factors such as coal rank, depth, and permeability affect the amount and distribution of methane in the coalbed and surrounding strata, which in turn determine the quantity and rate of methane release during mining. In addition, the type and rate of mining, as well as the geometry of the mine, have important implications for methane release. Because methane is a safety hazard in underground mines, substantial research has been undertaken to determine ways of predicting and controlling its emissions into mine working areas.

How Coalbed Methane Is Produced, Stored and Released

Coal is formed over millions of years as organic matter is transformed by complex processes known as "coalification." Coalification is controlled by chemical and physical processes, temperature, pressure and geologic history. Differing levels of coalification produce different "rank" coals, as shown in Figure D4-1.² Coalification results in both physical and chemical changes, including methane generation. Other byproducts of the coalification process are water and carbon dioxide.

The amount of methane produced increases throughout the coalification process. Thus, higher ranked coals tend to contain more methane than lower ranked coals. Methane is stored in the coal itself and can also be contained in the surrounding strata. In addition, some of the methane generated by coalification generally escapes to the atmosphere as a result of natural processes.



¹ This overview section is taken from the Coal Mining Chapter of the EPA Report to Congress entitled *Anthropogenic Methane Emissions in the United States: Estimates for 1990*.

² The term "rank" is used to designate differences in coal that are due to the progressive change from lignite to anthracite. Higher rank coals contain more fixed carbon, less volatile matter, and less moisture.

How Methane Is Stored in Coal

Large amounts of methane can be stored within the microstructure of coal. Methane storage in coalbeds, mainly by adsorption onto internal coal surfaces, is a function of rank, and present day pressure and depth of burial.³ In general, coals of increasing rank have higher storage capacities. In addition, storage capacity increases almost linearly with increasing pressure or depth. Therefore, at a given rank, deeper coals store more gas than shallower ones.

Even high rank coals cannot store all of the methane generated during coalification, however. The highest gas contents measured for anthracite coal in the United States, for example, are only 10 to 12 percent of the total amount of methane that was generated during coalification. The rest of the methane migrated out of the coal over time. Some of this gas remains stored in the surrounding strata, and some has likely been emitted to the atmosphere as a result of natural processes.

Factors Determining Methane Emissions

Methane is released when pressure within a coalbed is reduced, either through mining or through natural erosion or faulting. Methane will migrate through coal from zones of higher concentration to zones of lower concentration until it intersects a pathway, such as a cleat, joint system or fracture. The size, spacing, and continuity of such pathways determines the permeability of the coal and largely controls the flow of methane through the coal and to the surface or the mine workings.

During mining, methane is liberated by the mined coal seam as well as surrounding coal seams and/or gas bearing strata. The amount of methane liberated can be many times higher than the amount of methane contained in the mined coal seam.

As pressure is reduced during mining, methane is liberated from the seam being mined and from the strata above and below the mined seam. In addition to the rank and depth of the coal, the amount of disturbance to the surrounding strata as a result of mining activities will also have important implications for emissions. The amount of methane liberated by mining activities can exceed the amount of gas contained in the mined coal by as much as 3 to 9 times (Kissell et al. 1973).

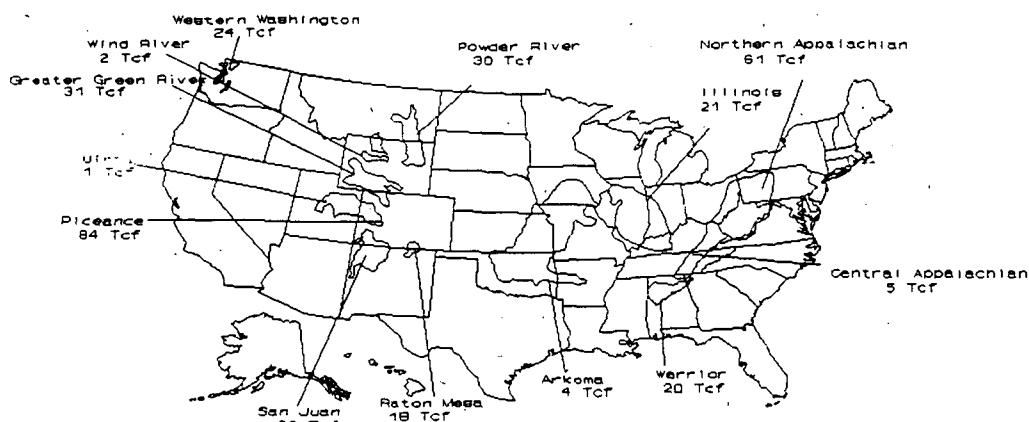
U.S. Mining Techniques

Coal is produced in the United States in surface and underground mines, and the choice between these mining types depends primarily on the thickness of the coalbed and its depth from the surface. Coalbeds shallower than about 200 feet are generally mined from the surface, while deeper coalbeds are usually mined by underground methods. Given enough coal thickness, surface mining methods can be applied to a depth of several hundred meters. Each mining method has different implications for release of methane to the atmosphere.

The major U.S. coal basins are shown in Figure D4-2. In general, coal in the Western basins is mined using surface methods, while most Eastern basin coals are mined using underground

³ Adsorption is the adhesion in an extremely thin layer of molecules to the surfaces of solid bodies with which they are in contact.

Figure D4-2: U.S. Coal Basins and Coalbed Methane Resources



methods.

Underground Mining

Underground mining accounted for about 40 percent of total U.S. coal production in 1990. Most underground mining occurs in the Eastern United States, primarily in the Northern and Central Appalachian Basins (including Pennsylvania, Virginia, West Virginia, Ohio, Kentucky) and the Black Warrior Basin of Alabama.

Most U.S. underground mines are less than 984 feet deep, but several reach depths of 1,968 to 2,296 feet. Methane can be emitted during mine construction, coal production, and from abandoned mine workings. The bulk of the emissions tend to be associated with coal production, however, and in particular with the caving of the roof and floor rocks, which creates pathways for the gas to move into the mine workings from unmined areas of the target coal seam and other strata.

Two underground mining methods are commonly used in the United States: room-and-pillar mining and longwall mining. The choice between these methods depends on geologic factors, such as depth and terrain, and economic factors, such as equipment cost. Longwall mines are typically bigger and deeper than room-and-pillar mines. They are also more expensive to equip and operate, but generally have higher coal production rates. The higher production, coupled with the more extensive caving typically associated with longwall mines, tends to result in higher methane emissions.

Longwall mining tends to liberate more methane than room-and-pillar mining. Thirty-six of the 50 gassiest underground mines in the U.S. use longwall mining methods.

Room-and-pillar mining is the most common underground mining technique in the United States, although the number of longwall mines is growing. Mechanized longwall mining was introduced in the U.S. during the 1960's, and today there are almost 100 longwall mines in operation.

Sixty out of the 100 gaggiest U.S. underground mines use longwall mining methods.

Surface Mining

Surface mining, also called strip mining, is used to mine coal at shallow depths. In essence, it involves large scale earth-moving; first the overburden on top of the coal is excavated, and then the coal can be removed. Coal recovery rates at surface mines can exceed 90 percent.

In 1990, 603 million tons of coal was produced at surface mines, mostly in sub-bituminous and lignite mines in the Western United States. This represented about 60 percent of total U.S. coal production. The largest and fastest growing U.S. surface mining region is the Powder River Basin of Wyoming and Montana. Surface mines are also located in the lignite fields of North and South Dakota and Montana, and the Eastern bituminous coal basin in Illinois, Indiana, and Western Kentucky.

Methane emissions from surface mines are highly uncertain. Available information indicates that emissions per ton of coal mined are likely to be low because these coals are generally low ranked and buried close to the surface.

Methane emissions at surface mines are not required to be monitored because this methane is emitted directly into the atmosphere and does not pose a safety hazard to miners. Thus, few emission measurements are currently available. The U.S. Environmental Protection Agency's Office of Research and Development (EPA/ORD) has recently undertaken a field measurement study of methane emissions from surface mines.

Based on available information, it appears that methane emissions from surface mines are low as compared to underground mines because the coals are typically lower ranked and are buried at shallower depths. Given the magnitude of coal production from surface mining, however, this emission source is not insignificant.

Methane Management Systems for Underground Mining

Methane is a serious safety threat in underground coal mines because it is highly explosive in atmospheric concentrations of 5 to 15 percent. The U.S. Mine Safety and Health Administration (MSHA), an agency of the U.S. Department of Labor, requires close monitoring of methane levels and careful design of mine ventilation systems to ensure that methane concentrations are kept below explosive levels in underground mines. In mine entries used by personnel, methane levels cannot exceed 1 percent, and in certain designated areas of the mine not frequented by mine personnel, methane levels cannot exceed 2 percent. If these concentrations are exceeded, MSHA requires that coal production cease until the ventilation system is able to reduce methane concentrations to acceptable levels.

Many gassy U.S. underground mines use degasification systems in addition to ventilation to ensure safe mining conditions. These systems produce high quality methane that can be sold to pipelines or used to generate electricity.

A variety of methane control methods are employed in many U.S. mines because of the hazard and because the costs of elevated methane concentrations can be high if coal production must

be suspended. Historically, ventilation has been the main technique used for controlling methane concentrations in coal mines. In many mines, however, methane emissions into the mine workings cannot be economically maintained at safe levels using ventilation alone and other degasification systems are used. These systems can recover methane before, during or after mining and keep it from migrating into the mine working areas.

Mine degasification systems are currently used primarily to improve safety and reduce ventilation costs. However, these systems can recover methane with a high enough energy content to warrant sale to pipelines or use for electricity generation. In addition to the potential economic benefits associated with the sale of this gas, such projects have the added advantage of reducing atmospheric methane emissions, a potent greenhouse gas. Methane management methods are summarized in Table D4-1.

Table D4-1

Mine Degasification Approaches

Method	Description
Ventilation	<ul style="list-style-type: none"> Universal method to dilute and exhaust methane to the atmosphere. Sufficient, in many mines, to maintain safe mining conditions. In gassy mines, may be necessary to supplement with other methane degasification systems.
Vertical Wells in Advance of Mining	<ul style="list-style-type: none"> Pre-drains methane via surface wells before mining operations begin. Can recover large amounts of pipeline quality methane. Technology also used to produce gas from coal seams that are not being mined. Can produce methane from multiple coal seams.
Gob Wells	<ul style="list-style-type: none"> Used in longwall mining to drain methane from portions of overlying strata allowed to collapse after mining ("gob areas") via surface wells. Can recover large amounts of methane, sometimes contaminated with mine air.
Horizontal Boreholes	<ul style="list-style-type: none"> Drilled from inside the mine to degasify the coal seam being mined either years in advance of or shortly before mining. Methane is removed through an in-mine piping system. Can recover pipeline quality gas.
Cross-Measure Boreholes	<ul style="list-style-type: none"> Drilled from inside the mine to degasify the overlying or underlying coal and rock strata. Methane is removed through an in-mine piping system. Gas can become contaminated with mine air during production. Used infrequently in the U.S.

Source: For more information, refer to Baker et al. 1988; Baker et al. 1986; Duel et al. 1988; Dixon 1987; U.S. EPA 1990a; and U.S. EPA 1990b.

Certain methane recovery techniques, particularly vertical drainage in advance of mining, have also been used extensively to recover coalbed methane in non-mining areas. These projects, which were encouraged in part by the Section 29 of the Internal Revenue Code Unconventional Gas tax credit, recovered almost 350 Bcf (9.9 Bcm) of coalbed methane in 1990, primarily in the Black Warrior Basin of Alabama and the San Juan Basin of Colorado and New Mexico. Because these projects are not associated with mining, they did not affect methane emissions from this source. Methane emissions from stand-alone coalbed methane production, processing and transmissions are included in the discussion of natural gas systems.

Post-Mining Emissions

Not all of the methane contained in coal is released during mining. Some methane remains in the coal after it is removed from the mine and can be emitted over the following days as the coal is transported, processed and stored. Depending on the characteristics of the coal and the way it is handled after leaving the mine, the amount of methane released during post-mining activities can be significant and can continue for days or even months. The greatest releases occur when coal is crushed, sized, and dried in preparation for industrial or utility uses (U.S. EPA, 1990).

DESCRIPTION OF WORKBOOK METHOD

The basic approach recommended in the workbook section of this report for estimating state methane emissions from coal mining is to multiply a methane emissions factor by the quantity of coal produced from underground and surface mines in the state. These emissions factors vary depending upon the coal basin(s) where the state is located. The emissions factors used in the workbook were developed based on the emissions estimates shown in the coal mining chapter of the EPA Report to Congress *Anthropogenic Methane Emissions in the U.S.* (U.S. EPA 1993).⁴ This section provides a brief description of the methodology that was used in the EPA Report to Congress to estimate coal mine methane emissions from underground mines, surface mines, and post-mining activities.

Underground Mines

The emissions coefficients for underground mines were developed by using selected emissions data from 1990. Methane emissions from underground mining include: (1) measured methane emissions from ventilation systems at the gassiest underground mines; (2) estimated emissions from ventilation systems from mines for which measurements were not reported; and, (3) estimated emissions from degasification systems.

Ventilation Emissions

- **Measured Ventilation Emissions.** Methane emissions from ventilation systems are reported for about 200 of the gassiest U.S. underground coal mines. A database compiled from 1990 Mine Safety and Health Administration (MSHA) inspection data by the U.S. Bureau of Mines (U.S.BOM) shows the daily methane emissions from

⁴ The emissions estimates shown in the EPA Report are based on 1988 methane emissions data -- the latest year for which data was available at the time the report was published. Recently, the emissions estimates developed for that report were updated, using 1990 data. The emissions factors used in this workbook are based on the 1990 data.

mines with emissions exceeding 100,000 cubic feet per day. The reported methane emissions for these approximately 200 gassy mines was used to determine the quantity of methane emitted from ventilation systems.

- Estimated Ventilation Emissions. Methane emissions from ventilation systems were estimated for the underground mines not included in the U.S. BOM database. These other mines were classified into three categories: (1) Active mines with detectable methane emissions; (2) Active mines with non-detectable methane emissions; and (3) Inactive or abandoned mines. Estimation methodologies were developed based on information provided by U.S. BOM and MSHA about the mines' characteristics and regulatory treatment. The estimated ventilation emissions for these mines were estimated to represent less than 2 percent of the measured ventilation emissions in 1990. This factor was applied to the actual ventilation emissions for each coal basin.

Degassification System Emissions

Specific information on methane emissions from the degassification systems in place at U.S. coal mines is not currently available because coal mine owner/operators are not required to report emissions from these systems. In fact, without close examination of the mine ventilation plans provided to MSHA for each mine, it is difficult to confirm which mines have degassification systems in place.

Degassification system emissions were estimated for mines known or believed to have such systems in place.⁵ Low and high estimates were developed based on information about likely coal mine degassification strategies and on conditions in various coal basins. The percentage of methane liberations assumed to be recovered by degassification systems at mines in different basins is: Northern Appalachian and Illinois (30 to 65 percent) and Central Appalachian, Black Warrior, and Western (40 to 65 percent). Known recovery factors were applied to those mines that reported the methane recovery from their degassification systems (*i.e.*, those mines that sold the gas to pipelines). The recovery factors were applied to the measured ventilation emissions of the roughly 30 mines with degassification systems in place in 1990 to estimate total emissions.

Once ventilation and degassification emissions were calculated for individual mines, total emissions from underground mines could be calculated for each basin. These emissions were then divided by total coal production in 1990 for each basin to determine the estimated emissions factor per ton of coal mined. The emissions factors are:

<u>Basin</u>	<u>Emissions Factor (cf/ton of coal mined)</u>
Northern Appalachian	423 to 739
Central Appalachian	217 to 327
Black Warrior	2504
Illinois	160 to 192
Rockies & Southwest	369 to 467

⁵ This list was developed based on discussions with U.S. BOM and MSHA officials, industry representatives and literature review.

These emissions factors are recommended in the methodology shown in Workbook Section 4.

Surface Mines

Measurements of methane emissions from surface mines are currently unavailable, although a field measurement study is underway to better quantify emissions from this source.⁶ In the absence of measurements, emissions were estimated using reported methane contents for the surface coals mined in each coal basin. For each coal basin, the estimated methane content of the coal was multiplied by an emission factor and by the basin's surface coal production. In the low case, an emission factor of 1 was used; that is, it was assumed that only the methane actually contained in the mined coal seams would be emitted. In the high case, however, it was assumed that actual emissions would be 3 times greater than the methane content of the target coal seam due to the release of methane from the surrounding strata.⁷ Using this approach, a low and high emissions factors per ton of coal mined was calculated for each basin. These emissions factors are shown in Workbook Section 4.

Post-Mining Emissions

The methane emitted during the post-mining transportation and handling of coal has not been systematically measured or evaluated. Previous analyses have estimated that 25 to 40 percent of the *in-situ* methane content of extracted coal would be released to the atmosphere after the coal leaves the mine. British Coal, for example, estimates that post-mining emissions are 40 percent of the *in-situ* content because their coals have low permeability and the gas desorbs slowly.⁸ Similarly, Environment Canada estimates that only 54 percent of the methane contained in their surface mined coals is released during mining.⁹

In the absence of actual measurements for U.S. coals, post-mining emissions were estimated to range from 25 to 40 percent of *in-situ* content. The low case estimate of 25 percent represents a conservative assumption, while the high case is more consistent with experience in other countries. For each coal basin, these emissions factors were applied to the methane contents reported for surface and underground coals to develop post-mining emissions factors. These emissions factors are presented in Workbook Section 4.

A more detailed description of the approaches used to estimate methane emissions from surface mines, underground mines, and post-mining activities is contained in the EPA Report to Congress (EPA, 1993).

⁶ This study is being done by EPA/ORD.

⁷ This assumption is consistent with the methodology developed by Environment Canada in their report on greenhouse gas emissions. (Environment Canada, 1992.) Preliminary results of the U.S. EPA study indicate that the factor could be as high as five (Kirchgessner et al 1992).

⁸ *Quantification of Methane Emissions from British Coal Mine Sources*, report produced for the Working Group on Methane Emissions, the Watt Committee on Energy (1991).

⁹ *Canada's Greenhouse Gas Emissions Estimates for 1990*. Draft April, 1992.

ALTERNATE METHODOLOGY

The approach recommended in Workbook Section 4 for calculating methane emissions from *underground* mines consists of multiplying state coal production from underground mines by the appropriate emissions factor. As described above, the emissions factors shown in the workbook were developed by summing the measured methane emissions from ventilation systems reported for individual mines and by estimating the quantity of methane emitted from degasification systems. While the mine-level emissions data were used to estimate total emissions from the major coal basins, this same approach could be used to estimate state-level emissions. Use of mine-level emissions data is the focus of the alternative method described here. This approach is the most precise method for estimating underground emissions since it relies on reported emissions from individual mines.

This alternative, mine-by-mine approach for underground mines is possible because methane emissions from ventilation systems at the 200 gaggiest underground mines are measured by MSHA and reported in a database developed by the U.S. BOM. However, MSHA is not required to monitor emissions from degasification systems and these emissions must still be estimated. Furthermore, states would still need to estimate emissions from ventilation systems at those less gassy mines not included in the U.S. BOM database (instructions for making these estimates are included here). Finally, emissions from surface mines and post-mining emissions would still need to be estimated using basin-specific emissions factors for each ton of coal mined, as shown in the workbook section.

For purposes of facilitating state efforts to estimate methane emissions from underground coal mines, the U.S. BOM database of methane emissions from gassy mines is included in Appendix A at the end of this Chapter. Additionally, estimates of emissions from degasification systems for mines that employ these systems are shown. The information in the database has been sorted by state to create individual state databases. Databases were created for the following states: Alabama, Colorado, Illinois, Indiana, Kentucky, Maryland, New Mexico, Ohio, Pennsylvania, Tennessee, Utah, Virginia, and West Virginia. The information for each state is shown in Tables 1 through 13 in Appendix A. A few states -- Maryland, New Mexico, and Tennessee -- have less than five gassy underground mines in the database.

The steps for calculating emissions using the state emissions databases shown in the Appendix are as follows:

Step 1: Locate the table in Appendix A containing the emissions data for your state. After you have located this table, review the instructions for interpreting the state databases, which appear at the beginning of Appendix A.

As described in the Instructions for Interpreting the State Databases, the total amount of methane emitted from gassy mines in the state in 1990 is shown in *Column 11*. Record this amount in Row 1 of Table D4-2 (Table D4-2 appears after the following page).

Step 2: Next, determine total state coal production from *all* active underground mines in 1990. Report this amount in Row 2 of Table D4-2. Total state coal production from underground mines should be available from in-state sources. Alternatively, the report *Coal Production 1990* (DOE/EIA, 1991) provides coal production from underground and surface mines for all states.

- Step 3:** After recording total state coal production from underground mines in 1990, record the total amount of coal produced from *gassy* mines listed in the U.S. BOM database. The total amount of coal produced is shown in the last row of *Column 4* in the state database. Report this amount in Row 3 of Table D4-2.
- Step 4:** Subtract total state coal production from underground mines (Row 2 of Table D4-2) from total coal production from gassy mines (Row 3 of Table D4-2) to determine the quantity of coal produced from *non-gassy* underground mines. Record this amount in Row 4 of Table D4-2.
- Step 5:** Multiply the total coal production from non-gassy mines in 1990 by an estimated average emissions factor of 50 cf/ton to estimate total methane emissions from non-gassy underground mines.
- Step 6:** Record this amount in Row 6 of Table D4-2.
- Step 7:** To determine total state methane emissions from underground mines in 1990, sum the emissions from gassy mines and the emissions from non-gassy mines. Record this amount in Row 7 of Table D4-2.

Table D4-2: Calculations for 1990 Methane Emissions from Underground Mines Using Alternate Methodology

Item to be Reported	Units	Value
(1) Methane Emitted from <i>Gassy</i> Mines in 1990 (Shown in Column 11 of the state database)	(million cubic feet/year)	
(2) Total State Coal Production from <i>All</i> Underground Mines in 1990	(million tons/year)	
(3) State Coal Production from <i>Gassy</i> Mines in 1990 (shown in Column 4 of the state database)	(million tons/year)	
(4) State Coal Production from <i>Non-gassy</i> Mines in 1990 (Row 2 minus Row 3)	(million tons/year)	
(5) Methane Emissions Factor for Coal Produced from <i>Non-gassy</i> Mines	(cf/ton)	50 cf/ton
(6) Methane Emitted from <i>Non-Gassy</i> Mines in 1990 (Row 4 x Row 5)	(million cubic feet/year)	
(7) Total State Emissions from All Underground Mines in 1990 (Row 1 + Row 6)	(million cubic feet/year)	

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APPENDIX A

Instructions for Interpreting State Emissions Databases: Emissions Data for Gassy Underground Mines

The state databases in this Appendix show estimates of 1990 methane emissions for approximately the top 200 gassy mines in the United States. These top 200 mines are estimated to account for over 95 percent of all methane emissions from underground mines. Following are instructions for how to interpret the data presented in the state databases.

Column 1: The first column of the database lists, in alphabetical order, the gassy mines that are located in each state.

Column 2: Column 2 shows the county in which the mines are located.

Column 3: Column 3 lists the company that owns the gassy mine.

Column 4: This column provides the amount of coal produced at each mine in 1990. Coal production is reported in million (mm) tons/year.

Column 5: Column 5 shows the estimated quantity of methane that was emitted from the ventilation system at each mine during 1990. This amount is based on the daily emissions from ventilation systems reported by the Mine Safety and Health Administration.

Column 6: This column indicates whether a particular mine is known or believed to have a degasification system in place (as reported in USEPA, 1994). A "1" in the column indicates that the mine does employ such a system. Some states do not have any mines that use degasification systems. Accordingly, for those states, column 6 will be blank.

Column 7: Column 7 shows the estimated percentage of total emissions that are released from ventilation systems. For those mines that do not use degasification systems, emissions from ventilation systems constitute 100 percent of the emissions released from the mine. Accordingly, for those mines, a value of 100 percent appears in column 7. In contrast, for those mine employing degasification systems, methane is emitted from both the ventilation systems and from the degasification systems. As a LOW estimate, it is assumed that ventilation emissions account for between 60 to 70 percent of total emissions, while degasification emissions account for only 30 to 40 percent of emissions. The specific percentages listed for each mine in the database vary depending upon the coal basin in which the mine is located and are based on the report USEPA (1993).

While the database only provides calculations corresponding to a LOW estimate of the portion of emissions contributed by degasification systems, states are also encouraged to develop a HIGH estimate by assuming that degasification system emissions account for 60 percent of total emissions at the mines employing these systems (and, therefore, that ventilation emissions account for only 40 percent of total emissions). The LOW estimate should correspond to the LOW emissions factor for underground mining shown in the workbook section, while the HIGH estimate should correspond to the HIGH emissions factor shown in the workbook section.

Column 8: Column 8 shows the estimated amount of methane released from degasification systems based on the percentages shown in Column 7 for ventilation emissions. The value in Column 8 is calculated as follows:

[ventilation emissions (Column 5)] / [ventilation emissions as percentage of total emissions (Column 7)] = Total Emissions.

Total Emissions x (1 - % shown in Column 7) = emissions from degasification systems.

Column 9: Column 9 shows the total amount of methane released from both ventilation systems (Column 5) and from degasification systems (Column 8).

Column 10: This column shows the amount of methane that was recovered for pipeline sales (and, thus, was not emitted to the atmosphere). In 1990, only six mines recovered methane for pipeline sales -- five in Alabama and one in Utah. Accordingly, Column 10 will be blank for states other than Utah and Alabama. Currently, in addition to the six mines that recovered methane in 1990, four states in Virginia also recover methane for pipeline sales.

Column 11: Column 11 shows the total amount of methane emitted to the atmosphere. The amount shown in Column 11 is calculated by subtracting the amount of methane recovered (Column 10) from the total amount of methane released (Column 9). Column 11 is the amount of methane emitted from gassy coal mines in the state during 1990.

Column 12: Column 12 shows the operating status of each mine as of September 1994. This information is based on the EPA Report *Identifying Opportunities for Methane Recovery at U.S. Coal Mines: Draft Profiles of Selected Gassy Underground Coal Mines*. While all of the mines shown in the database were operating in 1990, a number of them have since been closed or idled. Furthermore, during the last four years, new gassy mines have also started production. Unfortunately, emissions data are not available for these new mines.

ALABAMA

1 Mine Name	2 County	3 Company Name	4 Coal Production (mmtons/yr)	5 Vent Emissions (mmcf/yr)	6 Degas System In Place?	7 Vent Emis % of Total	8 Low Degas Released (mmcf/yr)	9 Low TOTAL Released (mmcf/yr)	10 Methane Utilized (mmcf/yr)	11 Low TOTAL Emissions (mmcf/yr)	12 Operating Status 1994
Blue Creek No.3	Jefferson	Jim Walter Resources Inc.	2.63	5,548	1	66%	2,849	8,397	2,849	5,548	Utilizing
Blue Creek No.4	Tuscaloosa	Jim Walter Resources Inc.	2.96	4,344	1	66%	2,230	6,574	2,230	4,344	Utilizing
Blue Creek No.5	Tuscaloosa	Jim Walter Resources Inc.	1.61	7,081	1	66%	3,636	10,717	3,636	7,081	Utilizing
Blue Creek No.7	Tuscaloosa	Jim Walter Resources Inc.	2.98	6,023	1	66%	3,092	9,115	3,092	6,023	Utilizing
Chetopa	Jefferson	Drummond	0.67	438		100%	0	438	0	438	Operating
Mary Lee No.1	Walker.	Drummond	1.63	767		100%	0	767	0	767	Operating
Mary Lee No.2	Walker	Drummond	1.20	146		100%	0	146	0	146	Closed
North River No. 1	Fayette	Pittsburgh & Midway	1.87	730		100%	0	730	0	730	Operating
Oak Grove	Jefferson	U.S. Steel Mining Co. Inc.	1.82	4,198	1	65%	2,260	6,458	2,260	4,198	Utilizing
TOTAL			17.36	29,273			14,068	43,341	14,068	29,273	

COLORADO

1 Mine Name	2 County	3 Company Name	4 Coal Production (mmtons/yr)	5 Vent Emissions (mmcft/yr)	6 Degas System In Place?	7 Vent Emis % of Total	8 Low Degas Released (mmcft/yr)	9 Low TOTAL Released (mmcft/yr)	10 Methane Utilized (mmcft/yr)	11 Low TOTAL Emissions (mmcft/yr)	12 Operating Status 1994
Cameo No.1	Mesa	Powederhorn Coal Co.		37		100%	0	37	0	37	Unknown
Orchard Valley West	Delta	Cyprus Coal Co.	0.58	219		100%	0	219	0	219	Operating
Deserado	Rio Blanco	Western Fuels-Utah	1.46	548	1	60%	365	913	0	913	Operating
Dutch Creek M & B	Pitkin	Mid-Continent Resources	0.48	2,117	1	60%	1,411	3,528	0	3,528	Closed
Eagle No. 5	Moffat	Cyprus Empire Corp	2.25	37	1	60%	.24	61	0	61	Operating
Golden Eagle	Las Animas	Wyoming Fuel Co.	1.28	2,227		100%	0	2,227	0	2,227	Operating
McClane Canyon	Garfield	Salt Creek Mining	0.21	73		100%	0	73	0	73	Unknown
Mt. Gunnison No. 1	Gunnison	West Elk Coal Co.	0.56	73		100%	0	73	0	73	Operating
Roadside	Mesa	Powderhorn Coal Co.	0.19	73		100%	0	73	0	73	Unknown
Southfield	Freemont	Energy Fuels	0.30	219		100%	0	219	0	219	Operating
TOTAL			7.30	5,621			1,801	7,422	0	7,422	

ILLINOIS

1 Mine Name	2 County	3 Company Name	4 Coal Production (mmtons/yr)	5 Vent Emissions (mmcf/yr)	6 Degas System In Place?	7 Vent Emis % of Total	8 Low Degas Released (mmcf/yr)	9 Low TOTAL Released (mmcf/yr)	10 Methane Utilized (mmcf/yr)	11 Low TOTAL Emissions (mmcf/yr)	12 Operating Status 1994
Baldwin Underground	Randolph	Peabody Coal Co.	1.87	73		100%	0	73	0	73	Unknown
Big Ridge	Saline	Arclar Co.	0.78	37		100%	0	37	0	37	Unknown
Brushy Creek	Saline	Kennellis Energies	1.70	255		100%	0	255	0	255	Operating
Crown II	Macoupin	Freeman United	1.15	146		100%	0	146	0	146	Unknown
Eagle No.2	Gallatin	Peabody Coal	1.60	438		100%	0	438	0	438	Closed
Elkhart	Logan	Turris Coal	1.32	110		100%	0	110	0	110	Unknown
Galatia No.56-1	Saline	Kerr McGee Coal	3.02	986		100%	0	986	0	986	Operating
Kathleen	Perry	Cutler Mining Co.	1.05	37		100%	0	37	0	37	Unknown
Marissa	Washington	Peabody Coal Co.	1.89	73		100%	0	73	0	73	Unknown
Monterey No.1	Macoupin	Monterey Coal	1.98	219		100%	0	219	0	219	Operating
Monterey No.2	Clinton	Monterey Coal	2.96	255		100%	0	255	0	255	Operating
Murdock	Douglas	Zeigler	0.99	219		100%	0	219	0	219	Unknown
Old Ben No.21	Franklin	Zeigler/Old Ben Coal	0.27	329		100%	0	329	0	329	Closed
Old Ben No.24	Franklin	Zeigler/Old Ben Coal	1.48	548		100%	0	548	0	548	Operating
Old Ben No.25	Franklin	Zeigler/Old Ben Coal	2.68	694	1	70%	297	991	0	991	Closed
Old Ben No.26	Franklin	Zeigler/Old Ben Coal	2.57	657	1	70%	282	939	0	939	Operating
Orient No.6	Jefferson	Freeman United	1.50	219		100%	0	219	0	219	Operating
Pattiki	White	White County Coal	1.75	767		100%	0	767	0	767	Operating
Peabody No.10	Christian	Peabody Coal	2.32	255		100%	0	255	0	255	Closed
Rend Lake	Jefferson	Consolidation Coal	2.77	438		100%	0	438	0	438	Operating
Sahara No.21	Saline	Sahara Coal	0.59	110		100%	0	110	0	110	Unknown
Spartan	Randolph	Zeigler Coal Co.	1.29	37		100%	0	37	0	37	Unknown
Wabash	Wabash	Amax Coal	2.01	986		100%	0	986	0	986	Operating
Zeigler No. 11	Randolph	Zeigler Coal Co.	1.66	73		100%	0	73	0	73	Unknown
TOTAL			41.18	7,957			579	8,536	0	8,536	

INDIANA

1 Mine Name	2 County	3 Company Name	4 Coal Production (mmtons/yr)	5 Vent Emissions (mmcf/yr)	6 Degas System In Place?	7 Vent Emis % of Total	8 Low Degas Released (mmcf/yr)	9 Low TOTAL Released (mmcf/yr)	10 Methane Utilized (mmcf/yr)	11 Low TOTAL Emissions (mmcf/yr)	12 Operating Status 1994
Buck Creek	Sullivan	Laswell Coal	0.78	110		100%	0	110	0	110	Unknown
TOTAL			0.78	110			0	110	0	110	

KENTUCKY

1 Mine Name	2 County	3 Company Name	4 Coal Production (mmtons/yr)	5 Vent Emissions (mmcft/yr)	6 Degas System In Place?	7 Vent Emis % of Total	8 Low Degas Released (mmcft/yr)	9 Low TOTAL Released (mmcft/yr)	10 Methane Utilized (mmcft/yr)	11 Low TOTAL Emissions (mmcft/yr)	12 Operating Status 1994
Aero No 1	Pike	Aero Energy Inc.	0.76	110		100%	0	110	0	110	Unknown
Lynch No. 37	Harlan	Arch of Kentucky Inc.	2.69	183		100%	0	183	0	183	Operating
Baker	Webster (KY)	Pyro Mining Corp.	1.22	255		100%	0	255	0	255	Operating
Camp No. 1	Union	Peabody Coal Co.	2.30	37		100%	0	37	0	37	Unknown
Camp No.2	Union	Peabody Coal	0.59	146		100%	0	146	0	146	Unknown
Canada Coal No. 2	Pike	Canada Coal Co. Inc.	0.06	37		100%	0	37	0	37	Unknown
Creech No 1	Harlan	Jericoli Mining Inc.	0.49	73		100%	0	73	0	73	Unknown
Darby	Harlan	Jericoli Mining Inc.	0.30	37		100%	0	37	0	37	Unknown
Day Branch No. 4	Harlan	Day Branch Coal Co. Inc.	0.18	37		100%	0	37	0	37	Unknown
Dotiki	Webster (KY)	Webster County Coal	2.41	110		100%	0	110	0	110	Unknown
EAS No. 1	Perry	Whitaker Coal Corp.	1.11	37		100%	0	37	0	37	Unknown
Green River No.9	Hopkins	Green River Coal	1.30	438		100%	0	438	0	438	Closed
Hamilton No. 2	Union	Island Creek Coal Co.	1.18	73		100%	0	73	0	73	Unknown
Martwick UG	Muhlenberg	Peabody Coal	1.59	110		100%	0	110	0	110	Unknown
MC NO 1	Pike	Mc Mining Inc.		110		100%	0	110	0	110	Unknown
New ERA No 1	Pike	New Era Coal Co.		110		100%	0	110	0	110	Unknown
Ohio No. 11	Union	Island Creek Coal Co.	1.19	37		100%	0	37	0	37	Unknown
Ovenfork/Scotia	Letcher	Cumberland River	1.19	438		100%	0	438	0	438	Unknown
Pontiki No.1	Martin	Pontiki Coal Corp.	0.94	255		100%	0	255	0	255	Operating
Pontiki No.2	Martin	Pontiki Coal Corp.	0.74	183		100%	0	183	0	183	Unknown
Pyro No. 11 Highway	Union	Pyro Mining Co.	0.05	73		100%	0	73	0	73	Unknown
William Station	Union	Pyro Mining		438		100%	0	438	0	438	Unknown
Wheatcroft	Webster (KY)	Pyro Mining		219	1	70%	94	313	0	313	Operating
Retiki	Henderson	Webster County Coal	1.14	37		100%	0	37	0	37	Unknown
Unicorn No. 2	Leslie	Unicorn Mining Inc.	0.75	37		100%	0	37	0	37	Unknown
West Hopkins	Hopkins	Sextet Mining Corp.	1.81	146		100%	0	146	0	146	Unknown
Whittaker No. 49	Leslie	Whitaker Coal Corp.	0.35	37		100%	0	37	0	37	Unknown
Wolf Creek No.4	Martin	Wolf Creek Collieries	2.88	438		100%	0	438	0	438	Operating
TOTAL			27.22	4,234			94	4,328	0	4,328	

MARYLAND

1 Mine Name	2 County	3 Company Name	4 Coal Production (mmtons/yr)	5 Vent Emissions (mmcf/yr)	6 Degas System In Place?	7 Vent Emis % of Total	8 Low Degas Released (mmcf/yr)	9 Low TOTAL Released (mmcf/yr)	10 Methane Utilized (mmcf/yr)	11 Low TOTAL Emissions (mmcf/yr)	12 Operating Status 1994
Mettiki	Garrett	Mettiki Coal Corp. (Mapco)	1.98	219		100%	0	219	0	219	Operating
TOTAL			1.98	219			0	219	0	219	

NEW MEXICO

1 Mine Name	2 County	3 Company Name	4 Coal Production (mmtons/yr)	5 Vent Emissions (mmcf/yr)	6 Degas System In Place?	7 Vent Emis % of Total	8 Low Degas Released (mmcf/yr)	9 Low TOTAL Released (mmcf/yr)	10 Methane Utilized (mmcf/yr)	11 Low TOTAL Emissions (mmcf/yr)	12 Operating Status 1994
Cimarron	Colfax	Pittsburgh & Midway Coal Mining	0.08	37		100%	0	37	0	37	Unknown
TOTAL			0.08	37			0	37	0	37	

OHIO

1 Mine Name	2 County	3 Company Name	4 Coal Production (mmtons/yr)	5 Vent Emissions (mmcft/yr)	6 Degas System In Place?	7 Vent Emis % of Total	8 Low Degas Released (mmcft/yr)	9 Low TOTAL Released (mmcft/yr)	10 Methane Utilized (mmcft/yr)	11 Low TOTAL Emissions (mmcft/yr)	12 Operating Status 1994
Meigs No.2	Meigs	Southern Ohio Coal	3.26	329		100%	0	329	0	329	Operating
Meigs No.31	Meigs	Southern Ohio Coal	2.15	329		100%	0	329	0	329	Operating
Powhatan No.4	Monroe	Quarto Mining	2.54	511		100%	0	511	0	511	Operating
Powhaton No.6	Belmont	Ohio Valley Coal	2.86	146		100%	0	146	0	146	Unknown
Saginaw	Belmont	Saginaw Mining Co.	0.47	37		100%	0	37	0	37	Unknown
Sunnyhill No. 9 South	Perry	Peabody Coal Co.	1.00	37		100%	0	37	0	37	Unknown
TOTAL			12.28	1,387			0	1,387	0	1,387	

PENNSYLVANIA

1 Mine Name	2 County	3 Company Name	4 Coal Production (mmtons/yr)	5 Vent Emissions (mmcf/yr)	6 Degas System In Place?	7 Vent Emis % of Total	8 Low Degas Released (mmcf/yr)	9 Low TOTAL Released (mmcf/yr)	10 Methane Utilized (mmcf/yr)	11 Low TOTAL Emissions (mmcf/yr)	12 Operating Status 1994
Allegheny No. 2	Allegheny	Penn Allegh Coal Co. Inc.	0.64	37		100%	0	37	0	37	Unknown
Bailey	Greene	Consol Pennsylvania Coal Co.	5.58	1,752	1	70%	751	2,503	0	2,503	Operating
Cambria No.33	Cambria	Beth Energy Mines Inc.	1.97	1,241	1	70%	532	1,773	0	1,773	Closed
Clyde	Washington	BCNR Mining Corp.		37		100%	0	37	0	37	Unknown
Cumberland	Greene	U.S. Steel Mining Co. Inc.	3.17	2,117	1	70%	907	3,024	0	3,024	Operating
DiAnne	Armstrong	Canterbury Coal Co.	0.67	37	-	100%	0	37	0	37	Unknown
Dilworth	Greene	Consolidation Coal	2.40	548		100%	0	548	0	548	Operating
Emerald No. 1	Greene	Cyprus Emerald Resources Cor	1.64	1,132	1	70%	485	1,616	0	1,616	Operating
Enlow Fork	Greene	Enlow Fork Mining	0.29	73		100%	0	73	0	73	New
Florence No.2	Indiana	Florence Mining	0.69	110		100%	0	110	0	110	Unknown
Gateway	Greene	Gateway Coal	0.33	292		100%	0	292	0	292	Unknown
Greenwich No.2	Indiana	Rochester & Pittsburgh Coal Co	1.53	548		100%	0	548	0	548	Unknown
Grove No. 1	Somerset	Lion Mining	0.61	219		100%	0	219	0	219	Operating
Homer City	Indiana	Helen Mining	0.98	475		100%	0	475	0	475	Closed
Jane	Armstrong	Keystone Coal Mining	0.88	146		100%	0	146	0	146	Unknown
Mine 84	Washington	Beth Energy Mines Inc.	1.33	1,132		100%	0	1,132	0	1,132	Operating
Lucerne No. 8	Indiana	Helvetia Coal Co.	0.67	37		100%	0	37	0	37	Unknown
Lucerne No.6	Indiana	Helvetia Coal	0.18	110		100%	0	110	0	110	Unknown
Lucerne No.9	Indiana	Helvetia Coal	0.73	146		100%	0	146	0	146	Unknown
Maple Creek	Washington	U.S. Steel Mining Co.	2.08	402		100%	0	402	0	402	Closed
Marion	Indiana	Tunnelton Mining	0.89	183		100%	0	183	0	183	Operating
Mathies	Washington	Mathies Coal	1.25	402		100%	0	402	0	402	Operating
Meadow Run	Greene	Genesis Inc.	0.21	37		100%	0	37	0	37	Unknown
Newfield	Allegheny	Penn Hills Energy Co./Kitt Ener	0.07	73		100%	0	73	0	73	Unknown
Rushton	Centre	Rushton Mining Co.	0.72	146		100%	0	146	0	146	Unknown
Shannopin	Greene	Shannopin Mining	0.97	146		100%	0	146	0	146	Unknown
Tanoma	Indiana	Tanoma Mining Co. Inc.	0.41	146		100%	0	146	0	146	Unknown
Urling No.1	Indiana	Keystone Coal Mining	0.97	402		100%	0	402	0	402	Operating
Urling No.3	Indiana	Keystone Coal Mining	0.32	37		100%	0	37	0	37	Unknown
Warwick Portal	Greene	Duquesne Light	0.06	146		100%	0	146	0	146	Unknown
TOTAL			32.23	12,301			2,675	14,975	0	14,975	

TENNESSEE

1 Mine Name	2 County	3 Company Name	4 Coal Production (mmtons/yr)	5 Vent Emissions (mmcf/yr)	6 Degas System In Place?	7 Vent Emiss % of Total	8 Low Degas Released (mmcf/yr)	9 Low TOTAL Released (mmcf/yr)	10 Methane Utilized (mmcf/yr)	11 Low TOTAL Emissions (mmcf/yr)	12 Operating Status 1994
Kelly's Creek No. 63	Sequatchie	Kelly's Creek Resources		37		100%	0	37	0	37	Unknown
Matthews	Claiborne	Consolidation Coal	0.85	73		100%	0	73	0	73	Unknown
TOTAL			0.85	110			0	110	0	110	

UTAH

1 Mine Name	2 County	3 Company Name	4 Coal Production (mmtons/yr))	5 Vent Emissions (mmcft/yr)	6 Degas System In Place?	7 Vent Emis % of Total	8 Low Degas Released (mmcft/yr)	9 Low TOTAL Released (mmcft/yr)	10 Methane Utilized (mmcft/yr)	11 Low TOTAL Emissions (mmcft/yr)	12 Operating Status 1994
Castle Gate	Carbon	Castle Gate Coal		146		100%	0	146	0	146	
Deer Creek	Emery	Utah Power & Light Co.	3.36	37		100%	0	37	0	37	Unknown
Emery	Emery	Consolidation Coal	0.34	110		100%	0	110	0	110	Unknown
Pinnacle	Carbon	Andalex Resources Inc.	0.84	146		100%	0	146	0	146	Unknown
Soldier Canyon	Carbon	Soldier Creek Coal	1.21	1,643	1	50%	1,643	3,285	1,643	1,643	Utilizing
Sunnyside No. 1	Carbon	Sunnyside Coal	0.68	621		100%	0	621	0	621	Closed
Sunnyside No. 3	Carbon	Sunnyside Coal		73		100%	0	73	0	73	Unknown
Trail Mountain No. 7	Emery	Beaver Creek Coal Co.	0.50	37		100%	0	37	0	37	Unknown
TOTAL			6.92	2,811			1,643	4,453	1,643	2,811	

VIRGINIA

1 Mine Name	2 County	3 Company Name	4 Coal Production (mmtons/year)	5 Vent Emissions (mmcft/yr)	6 Degas System In Place?	7 Vent Emis % of Total	8 Low Degas Released (mmcft/yr)	9 Low TOTAL Released (mmcft/yr)	10 Methane Utilized (mmcft/yr)	11 Low TOTAL Emissions (mmcft/yr)	12 Operating Status 1994
Bear Ridge No 1	Tazewell	Bear Ridge Mining Inc.	0.24	292		100%	0	292	0	292	Operating
B.C Seaboard No.1	Tazewell	Sea B Mining Co.	0.36	219		100%	0	219	0	219	Closed
B.C Seaboard No.2	Tazewell	Sea B Mining Co.	0.19	255		100%	0	255	0	255	Operating
Bodie Mining No. 1	Wise	Bodie Mining Co. Inc.	0.19	37		100%	0	37	0	37	Unknown
Buchanan No. 1	Buchanan	Consolidation Coal	2.60	3,468	1	60%	2,312	5,779	0	5,779	Utilizing
Bullitt	Wise	Westmoreland Coal	1.07	292		100%	0	292	0	292	Closed
Dominion No. 7	Buchanan	Dominion Coal Corp.	0.34	37		100%	0	37	0	37	Unknown
Double R No. 1	Dickenson	Double R Coal Co. Inc.	0.12	37		100%	0	37	0	37	Unknown
Falcon No. 1	Buchanan	Falcon Coal Corp.		73		100%	0	73	0	73	Unknown
G&A coal No. 1	Dickenson	G&A Coal Inc.	0.24	37		100%	0	37	0	37	Unknown
Holton	Lee	Westmoreland Coal	0.61	110		100%	0	110	0	110	Unknown
Jamb Mining No. 1	Dickenson	Jamb Mining Inc.	0.15	37		100%	0	37	0	37	Unknown
McClure No. 2	Dickenson	Clinchfield Coal Co.	0.13	37		100%	0	37	0	37	Unknown
McClure No.1	Dickenson	Clinchfield Coal	0.99	1,387		100%	0	1,387	0	1,387	Operating
Mullins No. 1	Wise	Mullins No. 3 Inc.		37		100%	0	37	0	37	Unknown
Prescott No. 2	Wise	Westmoreland Coal Co.	0.11	37		100%	0	37	0	37	Unknown
Raven No. 1	Buchanan	Koch Raven	0.30	73		100%	0	73	0	73	Unknown
Splashdam	Dickenson	Clinchfield Coal	0.54	73		100%	0	73	0	73	Unknown
VP No. 1	Buchanan	Island Creek Coal Co.	1.93	3,540	1	60%	2,360	5,901	0	5,901	Closed
VP No.3	Buchanan	Island Creek Coal Co.	1.75	3,358	1	60%	2,239	5,597	0	5,597	Utilizing
VP No.5	Buchanon	VP 5 Mining Co.	1.67	3,285	1	60%	2,190	5,475	0	5,475	Utilizing
VP No. 6	Buchanan	Garden Creek Poca Co	1.78	3,358	1	60%	2,239	5,597	0	5,597	Utilizing
Wentz No. 1	Wise	Westmoreland Coal Co.	0.30	37		100%	0	37	0	37	Unknown
Winston No. 10	Buchanan	Dominion Coal Corp.	0.23	37		100%	0	37	0	37	Unknown
Youngs Branch 15	Buchanan	Dominion Coal Corp.	0.40	37		100%	0	37	0	37	Unknown
TOTAL			16.24	20,185			11,339	31,524	0	31,524	

WEST VIRGINIA

1 Mine Name	2 County	3 Company Name	4 Coal Production (mmtons/yr)	5 Vent Emissions (mmcft/yr)	6 Degas System In Place?	7 Vent Emis % of Total	8 Low Degas Released	9 Low TOTAL Released	10 Methane Utilized	11 Low TOTAL Emissions	12 Operating Status 1994
Amonate No.31	McDowell	Consolidation Coal		803	1	60%	535	1,338	0	1,338	Unknown
Arkwright No. 1	Monongalia	Consolidation Coal Co.	1.90	1,424	1	70%	610	2,034	0	2,034	Operating
Bald Eagle No 1	Nicholas	Terry Eagle Coal Co.	0.18	37		100%	0	37	0	37	Unknown
Beckley	Wyoming	New Beckley Mining Corp.		110		100%	0	110	0	110	Unknown
Birchfield No.1	Boone	Birchfield Mining Inc.	1.29	548		100%	0	548	0	548	Unknown
Blacksville No. 1	Monongalia	Consolidation Coal	1.61	1,789	1	70%	767	2,555	0	2,555	Closed
Blacksville No. 2	Monongalia	Consolidation Coal	3.82	3,395	1	70%	1,455	4,849	0	4,849	Operating
Davidson No 1	Boone	Davidson Mining Inc.	0.88	110		100%	0	110	0	110	Unknown
Dobbin	Grant	Island Creek	1.83	110		100%	0	110	0	110	Unknown
Eagle Nest Inc.	Boone	Eagle Nest Inc..		37		100%	0	37	0	37	Unknown
Federal No. 2	Monongalia	Eastern Associated Coal	4.20	3,833	1	70%	1,643	5,475	0	5,475	Operating
Gary No. 2	McDowell	Gary Enterprises	0.20	37		100%	0	37	0	37	Unknown
Gary No.50	Wyoming	U.S. Steel Mining Co. Inc.		2,847		100%	0	2,847	0	2,847	Operating
Smokeless No. 4	Raleigh	Hansford Smokeless Inc.	0.48	1,095		100%	0	1,095	0	1,095	Unknown
Harris No.1	Boone	Eastern Associated Coal	1.69	73		100%	0	73	0	73	Unknown
Humphrey No.7	Monongalia	Consolidation Coal Co.	3.31	2,300	1	70%	986	3,285	0	3,285	Operating
Ireland	Marshall	Consolidation Coal	2.21	657		100%	0	657	0	657	Closed
Justice No.1	Nicholas	Eagle Coal & Dock Co.	0.09	37		100%	0	37	0	37	Unknown
Kermit No. 1	Mingo	Kermint Coal Co.	0.41	73		100%	0	73	0	73	Unknown
Lightfoot No.1	Boone	Eastern Associated Coal	1.48	73		100%	0	73	0	73	Unknown
Lightfoot No.2	Boone	Eastern Assoc. Coal	0.14	37		100%	0	37	0	37	Unknown
Loveridge No. 22	Marion	Consolidation Coal	2.77	1,861	1	70%	798	2,659	0	2,659	Operating
Maple Meadow No.1	Raleigh	Maple Meadow Mining Co.	1.26	1,205		100%	0	1,205	0	1,205	Operating
Martinka No. 1	Marion	Southern Ohio Coal	2.92	110		100%	0	110	0	110	Unknown
McElroy	Marshall	McElroy Coal	2.73	548		100%	0	548	0	548	Operating
Old Ben No. 20	Mingo	Old Ben Coal Co.	1.43	37		100%	0	37	0	37	Unknown
Osage No.3	Monongalia	Consolidation Coal Co.	1.82	1,387	1	70%	594	1,981	0	1,981	Operating
Rex	Kanawha	Rebb Energy Inc.	1.86	37		100%	0	37	0	37	Unknown
Robinson No.95	Marion	Consolidation Coal	0.68	767	1	70%	329	1,095	0	1,095	Operating
Rocky Hollow No. 1	Mingo	Rocky Hollow Coal Co.	0.73	37		100%	0	37	0	37	Unknown
Sentinel	Barbour	Philippi Development Inc		438		100%	0	438	0	438	Operating
Shawnee	Wyoming	U.S. Steel Mining	3.07	475	1	60%	316	791	0	791	Operating
Shoemaker	Marshall	Consolidation Coal	0.14	803		100%	0	803	0	803	Operating
Smoot	Webster	Smoot Coal Co. Inc.	0.11	110		100%	0	110	0	110	Unknown
Sunrise No. 1	McDowell	Sunrise Mining Inc.	0.23	37		100%	0	37	0	37	Unknown
Tommy Creek No. 1	Raleigh	Tommy Creek Coal Co.	0.50	37		100%	0	37	0	37	Unknown
Windsor	Brooke	Windsor Coal Co.	1.56	146		100%	0	146	0	146	Unknown
TOTAL			47.51	27,448			8,032	35,480	0	35,480	

DISCUSSION 5 ***METHANE EMISSIONS FROM LANDFILLS***

OVERVIEW

Methane (CH_4) and carbon dioxide (CO_2) are produced from anaerobic decomposition of organic matter in landfills by methanogenic bacteria. Organic waste first decomposes aerobically (in the presence of oxygen) and is then attacked by anaerobic non-methanogenic bacteria, which convert organic material to simpler forms like cellulose, amino acids, sugars, and fats. These simple substances are further broken down to gases and short-chain organic compounds (H_2 , CO_2 , CH_3COOH , HCOOH , and CH_3OH), which form the substrates for methanogenic bacteria. The resulting biogas consists of approximately 50 percent CO_2 and 50 percent CH_4 by volume, although the percentage of CO_2 may be smaller because some CO_2 dissolves in landfill water (Bingemer and Crutzen, 1987). Additionally, some landfills flare recovered landfill gas, which converts the methane portion of the gas to CO_2 .¹

Numerous factors affect the amount of CH_4 and CO_2 produced in landfills. The factors may be divided into two general categories: management practices and physical factors.

Management Practices

Waste Management Type (portion of waste that is landfilled)
Density of Refuse
Particle Size of Refuse

Physical Factors

Waste Composition
Moisture Content
Leachate pH
Nutrients
Landfill Temperature

Municipal solid waste (MSW) constitutes a significant portion of all types of waste produced in the United States and also the waste deposited in landfills that produce methane.² The two types of waste management practices that lead to methane production are open dumping and sanitary landfilling. Since CH_4 production from open dumping, or waste piles, is highly uncertain and based on anecdotal evidence, and since the amount of waste that is openly dumped in the United States is negligible, CH_4 emissions from open dumping are assumed to be zero.

In sanitary landfills, a tightly packed, anaerobic environment favorable for landfill gas production is created as compacted waste is spread evenly over the active area of the landfill and

¹ However, landfill CO_2 emissions are small compared to emissions from other sources discussed in this report. Also, the CO_2 generated is primarily from the decomposition of organic materials derived from biomass sources (e.g., crops, forests) which are assumed to be regrown on an annual basis. Therefore, these are not treated as net emissions from waste. If biomass raw materials are being unsustainably produced, the net CO_2 releases should be calculated in Workbook Section 10.

² Other types of waste that may produce methane in landfills are hazardous and industrial solid waste and agricultural waste. Hazardous and industrial waste landfills may contain compounds that will result in a low pH environment toxic to the methanogenic bacteria. Agricultural waste, if landfilled, could potentially be a significant source of methane emissions but is typically not deposited where anaerobic conditions develop (see Bingemer and Crutzen, 1987).

covered with some type of nonporous soil (e.g., clay). In order to avoid discrepancies over the term "landfill," this definition of sanitary landfill will be used in the methodology described below.

Other variables of management practices that affect CH₄ generation are density and particle size of refuse. By increasing density, a greater mass can be placed into a specified volume. As density increases, the degree of saturation (*i.e.*, the ability to absorb water) will increase due to greater mass, which can lead to more gas production per unit volume (Pacey and DeGier, 1986). One way to increase density is by shredding refuse. Shredding not only increases density, but also reduces particle size, which results in a greater surface area exposed to bacterial activity, moisture, and nutrients. In addition, if shredded refuse is spread evenly in thin layers (~12 inches) and then compacted, size could be further reduced. Extremely dense refuse (*i.e.*, baled refuse), however, cannot be penetrated by water, and consequently, may produce less gas (Pacey and DeGier, 1986). Other variables that may affect emissions are the design and size of the landfill and the use of cover soils.

The actual composition of the municipal solid waste is very important in determining the amount of landfill gas produced. Municipal solid waste supplies the necessary starting material for methane generation in landfills by providing degradable organic carbon (DOC) with which methanogenic bacteria interact to produce landfill gas.³ The majority of waste in the United States is paper and paper products, which contain a higher carbon content than food (40 percent by weight according to Bingemer and Crutzen, 1987) and will therefore produce more CH₄.

Another physical factor influencing landfill gas production is the moisture content of the landfill environment (Pacey and DeGier, 1986). Moisture is essential to anaerobic decomposition and the life of methanogenic bacteria. Water serves as a transport medium for nutrients, bacteria, and alkaline substances within the refuse (Pacey and DeGier, 1986). As moisture increases the bacteria become more active and multiply, increasing methane production. Unfortunately, no explicit functional relationship exists between moisture content of the landfill environment and gas production estimates (Emcon Associates, 1982).⁴ The moisture of the refuse, however, can be determined by analyzing the composition of the landfilled MSW and determining the percentage of "wet refuse" (*i.e.*, food wastes) and "dry refuse" (*i.e.*, paper waste). Ahuja (1990) attempts to include the percentage of dry refuse in the total amount of MSW landfilled, which contains the DOC available for methane production, in his methodology to estimate methane emissions. This methodology is discussed later in the section.

Other factors that are important but have not been factored into any emission estimate due to the lack of data include the leachate pH and nutrient availability. The optimal pH for gas production is near neutral, between 6.8 and 7.2, which is not usually reached for several years (Pacey

³DOC is biochemically decomposed to form substrates and can be divided into two parts: dissimilated and assimilated. The dissimilated fraction is the portion of carbon in substrates that is converted to landfill gas (*i.e.*, CO₂ and CH₄), and the assimilated fraction is the remainder of carbon that is used to produce new microbial cell material (Tabasaran, 1981).

⁴In a study recently conducted by U.S. EPA's Office of Solid Waste, a correlation between landfill gas generation rate and precipitation rate was obtained (no correlation between precipitation rate and moisture content in the landfill was evaluated). Based on data from 12 "wet" landfills (precipitation of 1.9 ft. or more) and data from 8 "dry" landfills (precipitation of less than 1.9 ft.), landfill gas emissions from "wet" landfills were ~2.6 times greater than emissions from "dry" landfills (Thorneloe, 1990).

and DeGier, 1986). Methane generation is not inhibited unless the environment is very acidic (pH < 6.0). Alkaline substances, transported in water, help to balance the pH level and hinder the formation of organic acids, which in large concentrations decrease methane production. Nutrients are essential to the life and growth of bacteria.

Temperature, unlike leachate pH, can be related to the amount of degradable organic carbon that will generate landfill gas (*i.e.*, the fraction of DOC dissimilated). At temperatures below 50-59°F, methane production is drastically reduced (Pacey and DeGier, 1986). Because the majority of methane production occurs in the deeper layers of the landfill, where heat is generated from anaerobic decomposition, temperatures typically range between 77-104°F. An average of 95°F can be expected within the anaerobic zone (below 6.5-13 ft.) (Gunnerson and Stuckey, 1986, in Bingemer and Crutzen, 1987) and will result in ~77 percent dissimilated DOC.⁵ At extremely high temperatures (above 140°F) methane generation usually ceases (Pacey and DeGier, 1986).

Landfill gas recovery can be an important factor in reducing CH₄ emissions from landfills as well as provide a source of renewable energy. Landfill gas recovery systems are increasing, and the CH₄ generated from landfills is being captured as an energy source. Currently, there are 120 sites in the U.S. where landfill gas is captured and used as an energy source. It would be beneficial to estimate the amount of CH₄ existing in the recovered landfill gas in order to subtract it from total CH₄ emitted from that state's landfills. This has been accounted for in the methodology, although each state will need to estimate its own quantity of CH₄ capture from biogas recovery sites.

Refuse may be disposed of by other management practices that do not produce methane such as incineration, materials recovery/recycling, and composting. These alternative methods of disposal may be more attractive than sanitary landfilling without gas recovery systems as land availability declines and potential health and environmental risks of landfilling increases in the U.S. For example, Japan prefers incineration over landfilling; about 73 percent of Japan's waste is disposed of by incineration and only 23 percent by sanitary landfilling (Hayakawa, 1990, in Thorneloe, 1991).

DESCRIPTION OF WORKBOOK METHOD

The preferred approach for estimating methane emissions from landfills in the U.S. would be to actually measure the emissions from each of the approximately 6,000 operating landfills and the thousands of closed landfills. Unfortunately, such an approach is impractical, if not impossible. Previous efforts to estimate emissions from landfills offer two alternative approaches:

- Determine the emissions "potential" of a representative quantity of refuse through theoretical considerations (*e.g.*, carbon content) or laboratory simulation. Scale this value to the state level by estimating the quantity of refuse in landfills statewide.
- Use available data to determine the actual generation rates of methane per unit of refuse and multiply this value by the estimated quantity of refuse disposed of in landfills statewide.

⁵Landfill temperature is related to the amount of DOC that is dissimilated to produce biogas by the relationship: $C_C / C_T = (0.014 T + 0.28)$, where C_C = carbon converted to biogas, C_T = total carbon compounds in substrates, and T = landfill temperature (Tabasaran, 1981). From this relationship, as temperature increases, so does the rate of gas formation.

The first approach has been the most frequently used method to estimate emissions from landfills. It relies on kinetic models of landfill gas formation or on simulations conducted in laboratories. This method assumes conditions that occur in kinetic models or under laboratory conditions closely simulate actual field conditions. This assumption limits the accuracy of the method, since it is difficult to determine whether theoretical or laboratory conditions actually simulate field conditions. The second approach, which relies on field measurements, is the preferred method of analysis because it relies on actual data rather than theoretical results.

The approach suggested for the workbook calculations is based on an emissions model developed for the report *Anthropogenic Methane Emissions in the U.S.: Report to Congress* (U.S. EPA 1993). This method uses a statistical model derived initially from analyses performed by the U.S. EPA Air and Energy Engineering Research Laboratory (AEERL) and enhanced by the U.S. EPA Office of Air and Radiation (OAR). Emissions estimates may be calculated by collecting data on the characteristics of the state's landfill population and applying this information to the method. The method presented in Workbook Section 5 consists of the following ten steps (for a more detailed description of these steps, please see the workbook):

- Step 1:** Obtain the required data.
- Step 2:** Estimate waste in place at MSW landfills.
- Step 3:** Estimate fraction of waste in large versus small landfills.
- Step 4:** Classify the state as arid or non-arid.
- Step 5:** Estimate waste in place at small MSW landfills.
- Step 6:** Estimate waste in place at large MSW landfills.
- Step 7:** Estimate total methane generated from MSW landfills.
- Step 8:** Estimate methane generated from industrial landfills.
- Step 9:** Adjust for flaring and recovery.
- Step 10:** Adjust for oxidation.

The emissions model on which this method is based was developed by examining and confirming data from 85 landfills that recover methane gas to produce energy. The data analyzed in detail the relationships between methane recovery and (1) refuse quantity; (2) refuse characteristics (e.g., moisture content, temperature, and pH); and (3) landfill characteristics (such as age, depth, volume, and surface area).⁶ The analysis showed that a simple model using the total amount of waste in place and the landfill's location in an arid or non-arid climate was adequate for estimating methane production. Because this method is based on the total waste in place at a landfill, and not on annual waste generation and disposal rates, it accounts for timed releases of methane instead of assuming that all of the methane generated is released in a single year.

The analysis indicated that the amount of methane gas generated per unit of waste was higher in landfills with over 1.1 million tons of waste in place than landfills with less than 1.1 million tons of waste in place. To account for this, a separate model was developed to calculate emissions from landfills with less than 1.1 million tons of waste in place.⁷ In summary, the emissions depend on

⁶ Please note that the analysis assumes that landfill wastes produce methane over a thirty year period. If the actual period is significantly longer, the emissions may be greatly understated.

⁷ The accuracy range of the equations for large landfills ($\pm 15\%$) is better than for small landfills ($\pm 20\%$) because the estimate for large landfills is based on a greater number of actual landfill methane production measurements.

three key factors: (1) total waste in place; (2) landfill size; and (3) location in an arid or non-arid climate. The four equations (arid/large, arid/small, non-arid/large, non-arid/small) are listed below:

Small landfills (< 1.1 million tons)

$$\text{Nonarid: Methane (ft}^3/\text{day) = 0.35 W (tons) } \pm 20\%$$

$$\text{Arid: Methane (ft}^3/\text{day) = 0.27 W (tons) } \pm 20\%$$

where:

W = Average waste in place (tons) at small landfills

Large Landfills (> 1.1 million tons)

$$\text{Nonarid: Methane (ft}^3/\text{day) = N \cdot (419,000 + 0.26 W}_{\text{avg}}\text{ (tons)) } \pm 15\%$$

$$\text{Arid: Methane (ft}^3/\text{day) = N \cdot (419,000 + 0.16 W}_{\text{avg}}\text{ (tons)) } \pm 15\%$$

where:

N = Number of large landfills in the state

W_{avg} = Average waste in place (tons) at large landfills

Because the models only determine the amount of gas *generated* by the landfill, the results of the model must be adjusted to determine actual *emissions*.⁸ As previously described, some of the methane produced by landfills is recovered to produce energy, flared to meet environmental and safety requirements, or oxidized in the soils covering the landfill.

Facilities that recover methane gas to produce energy should have sufficient records to estimate the amount of gas that is recovered with relative accuracy. Government Advisory Associates (GAA) publishes the *Methane Recovery from Landfill Yearbook*, providing a fairly accurate source for this information.

Information quantifying the amount of gas recovered by facilities for flaring is limited. Currently, no information exists explicitly documenting the amount of methane recovered and flared. Based on anecdotal evidence, it is assumed that the amount of methane flared is equal to 25 percent of the methane recovered for energy production.

Methane may also be oxidized in the top layer of soil over the landfill. Landfills that recover methane for energy recovery or flaring utilize a system of wells, pipes, and pumps to prevent the gas

⁸It should be noted that the analysis used to create the model is based on data describing the methane *recovered* from landfills. The methane recovery information is an imperfect surrogate for emissions measurements. If the landfills used in this analysis are not representative of landfills as a whole, then the models used in this analysis may not accurately represent state landfill methane generation.

from passing through the landfill cover. However, in landfills that do not operate recovery systems, the methane will pass through the soil cover of the landfill where it may be oxidized (Whalen, Reeburgh and Sandbeck, 1990). The amount of oxidation that occurs is uncertain and depends on the soil characteristics and the environment. Currently, there is limited research available to assist in quantifying the amount of methane that is eliminated during this process. For purposes of this exercise, it is assumed that 10 percent of the methane generated that is not recovered is oxidized in the soil.

Methane is also generated from waste deposited in non-hazardous industrial landfills. Although methane generation from non-hazardous industrial landfills is believed to be small relative to MSW landfills, industrial landfill methane generation is still a significant source of methane emissions. Note that methane generation from industrial landfills **does not** include methane generation from industrial waste disposed of into MSW landfills. This methane generation is already accounted for under MSW landfills.

Precise estimates of the quantity of waste in industrial landfills and its methane generation rate are not available. Based on estimates of the quantity of waste in place at industrial landfills and on the estimated organic content of industrial landfills compared to MSW landfills, EPA (1993) estimated that methane generation from industrial landfills in the U.S. is approximately 7 percent of methane generation from MSW landfills in the U.S. This 7 percent value may be used to estimate state methane generation from industrial landfills.

Alternatively, if state information is available on the quantity of waste in place (WIP) at industrial landfills, the ratio of emissions from industrial landfills to emissions from MSW landfills may be calculated as follows:

$$\frac{\text{Average 15\% organic content} \times \text{WIP at Industrial Landfills}}{\text{Average 65\% organic content} \times \text{WIP at MSW Landfills}}$$

The resulting value would be used in place of the 7 percent default value.

Methane emissions to the atmosphere will equal total methane production from municipal landfills adjusted for the methane produced by industrial landfills, the methane recovered, and the methane oxidized in the landfills before being released to the atmosphere. These adjustments can be described as:

Net Methane Emissions =	municipal landfill methane generation
<i>plus</i>	industrial landfill methane generation
<i>minus</i>	municipal methane recovery
<i>minus</i>	industrial methane recovery
<i>minus</i>	methane oxidation by soil.

ALTERNATE METHODOLOGIES

This section presents two alternative methods for estimating methane emissions from landfills if states are not able to obtain the data required to use the recommended method. The simplest methodology for estimating CH₄ emissions from landfills is based on a mass balance approach, where an instantaneous release of methane is assumed to enter the atmosphere during the same year that refuse is placed in the landfill (Bingemer and Crutzen, 1987). Furthermore,

Bingemer and Crutzen do not consider subsequent releases of CH₄ to the atmosphere from the MSW placed in a landfill that will be emitted in future years nor from previous years. The reason for this is that their approach implicitly assumes that all waste placed into a landfill during the year emits all potential methane immediately. Bingemer and Crutzen use four economic regions: U.S./Canada/Australia, Other OECD, USSR/E. Europe, and Developing Countries. Then they determine how much MSW is produced for each region and how much of that MSW is degradable organic carbon. To calculate the annual emissions from MSW, Bingemer and Crutzen used the following equation:

$$(1) \text{ Methane Emissions} = \text{Total MSW generated (lbs/yr)} \times \text{MSW landfilled (\%)} \times \text{DOC in MSW (\%)} \times \text{Fraction Dissimilated DOC (\%)} \times 0.5 \text{ lbs CH}_4/\text{lb biogas} \times \text{Conversion factor (16 lbs CH}_4/12 \text{ lb C)} - \text{Recovered CH}_4 \text{ (lbs/yr)}.$$

The MSW generation rates and composition data for the U.S. can be used to calculate methane emissions instead of the regional factors for U.S./Canada/Australia (see Table D5-1). Currently, no state-specific data are available, but each state can estimate its annual MSW generation rate and percentage of MSW landfilled. MSW generation rates and percentage of MSW landfilled for the U.S. have been estimated by the OECD/IEA (1989) as well and are presented in Table D5-1. Bingemer and Crutzen's regional estimates are for 1980 and are somewhat outdated; the country-specific estimates presented by OECD/IEA (1989) were taken from 1988 data or the nearest year to 1988 for which data were available. The U.S. EPA's Office of Solid Waste has also provided MSW and MSW landfilled figures.

Another methodology outlined by Ahuja (1990) is based on Bingemer and Crutzen's assumptions but is more detailed due to the addition of a new variable -- percentage of MSW that is dry refuse. Using assumptions by Bingemer and Crutzen (1987), % MSW as dry refuse, and an average landfill temperature of 95°F to derive the fraction of dissimilated DOC, methane emissions can be calculated as follows (Ahuja, 1990):

$$(2) \text{ Methane Emissions} = \text{Total MSW generated (lbs/yr)} \times \text{MSW landfilled (\%)} \times \text{DOC in MSW (\%)} \times \text{Dry Refuse (\%)} \times \text{Fraction dissimilated DOC (\%)} \times (0.5 \text{ lbs CH}_4/\text{lb biogas}) \times \text{Conversion factor (16 lbs CH}_4/12 \text{ lb C)} - \text{Recovered CH}_4 \text{ (lbs/yr)}.$$

A more complex method for estimating methane emissions from landfills is based on a first-order kinetic model, the Scholl Canyon model, which considers timed releases of methane to the atmosphere (Thorneloe, 1990). Best results are usually obtained when the model is applied to individual landfills, but it can be applied to an entire country such as the U.S. Estimates have been made for the U.S. using this model (e.g., Colt et al., 1990). Detailed information, such as waste generation and composition, moisture content, pH, temperature, available nutrients, landfill's age, size, type, and time since closure, is required to calculate emissions (Thorneloe, 1990). This method assumes that gas production will be highest upon initial placement of waste in the landfill, after a certain negligible lag period during which anaerobic conditions are formed. The rate then decreases exponentially (*i.e.*, undergoes first-order decay) as the degradable organic carbon available decreases (U.S. EPA, 1990). The model requires that MSW rates over the life

Table D5-1
Waste Disposal, Composition, and Waste Generation Estimates in the U.S.

Source	Year	% MSW Landfilled	% DOC of MSW	Waste Generation (lbs/cap/yr)
Bingemer and Crutzen (1987)	1980	91	22	4.0
U.S. EPA (1988a)	1986	83.2	NA	4.0
OECD (1989)	1985	62	NA	4.4
Picott et al. (1990)	1988	85	21	1.9
WRI (1990)	1983	NA	NA	4.6

of the landfill, or extended period of time (*e.g.*, 1960-1990), be used to estimate methane emissions more accurately. The model equations and variables are described briefly below:

$$Q_{CH_4} = k \times L_0 \times R \times e^{-kt}$$

where,

Q_{CH_4} = methane generation rate at year t (ft^3/yr),

L_0 = potential methane generation capacity ($ft^3/tons$ of refuse),

R = quantity of waste landfilled ($tons/yr$),

k = methane generation rate constant (yr^{-1}),

t = time since initial refuse placement (yr).

Theoretically, L_0 depends on the type of refuse only and is based on the chemical composition of refuse and its biodegradability. The methane generation constant, k , determines how quickly the methane generation rate decreases (U.S. EPA, 1990). The rate constant and the generation rate are related; the higher the value of k , the faster the methane generation rate decreases over time. The rate constant is affected by the same factors that affect L_0 , with the addition of temperature. Some of these variables themselves, such as L_0 and k , need to be calculated even before the equation can be used, although some values have been determined (*see, e.g.*, U.S. EPA, 1990). To date no functional relationships have been determined among these key factors and a better understanding of these factors is needed to more accurately calculate methane emissions from landfills with this approach.

AVAILABILITY OF DATA

In-state sources should be consulted to obtain data on total MSW generated and the amount of methane recovered from landfills. Ideally, in-state data sources should also be used for waste characteristics and waste management practices (*e.g.*, percent of MSW that is landfilled; percent of DOC contained in the MSW; and percent of DOC that is dissimilated). However, in many states, such data may not be readily available. In such cases, the average default values indicated in the workbook section should be used. Additionally, some data on waste generation, waste composition, and waste disposal are available from U.S. EPA (1988a).

UNCERTAINTIES

There are several uncertainties associated with using the recommended method for estimating methane emissions from landfills. First, the actual number and size of landfills and other waste management facilities are not known with certainty. Many small and unregulated facilities may exist that are not included in these estimates. Second, the time period over which landfill waste produces methane also is not certain. At present, the assumed time period is thirty years. This could be an overestimate or underestimate. Third, this methodology is based on information from methane recovered from various landfills. These landfills may not be representative of landfills as a whole. Fourth, little information is available on the amount of methane oxidized by the soil cover over landfills. The assumed ten percent is based on limited measurements. Lastly, the method of estimating methane emissions from small landfills is less accurate than the one for large landfills. This difference is due to the fact that more methane measurements were taken from large landfills than small ones. The basis for estimating emissions from small landfills needs to be improved. Other sources of uncertainty in estimating CH₄ emissions from landfills are the effects of climate on methane emission rates and the impact of landfill design characteristics and maintenance procedures (Piccot et al., 1990).

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DISCUSSION 6

METHANE EMISSIONS FROM DOMESTICATED ANIMALS

OVERVIEW

Methane is produced as part of the normal digestive processes of animals. Referred to as "enteric fermentation," these processes produce emissions that account for a significant portion of the global methane budget, about 65-100 Tg annually (IPCC, 1994). Of domesticated animals, ruminant animals (cattle, buffalo, sheep, goats, and camels) are the major source of methane emissions, with cattle being the most important source. Although wild ruminant animals, such as deer, and wild non-ruminant herbivores, such as rabbits, also produce methane, they are not included because emissions from these animals are considered a natural source.

Ruminant animals have a large "fore-stomach," or rumen, within which microbial fermentation breaks down feed into soluble products that can be utilized by the animal. Approximately 200 species and strains of microorganisms are present in the anaerobic rumen environment, although only a small portion, about 10 to 20 species, are believed to play an important role in ruminant digestion (Baldwin and Allison, 1983). The microbial fermentation that occurs in the rumen enables ruminant animals to digest coarse plant material that monogastric animals¹ cannot digest.

Methane is produced in the rumen by bacteria as a by-product of the fermentation process. This methane is exhaled or eructated by the animal and accounts for the majority of emissions from ruminants. Methane also is produced in the large intestines of ruminants and also is excreted. Non-ruminant herbivores such as horses, mules, rabbits, pigs, and guinea pigs have a limited amount of fermentation in the large intestines or ceca. The methane produced in this manner is quite small compared to the amount produced by ruminant animals.

There are a variety of factors that affect methane production in ruminant animals, such as: the physical and chemical characteristics of the feed; the feeding level and schedule; the use of feed additives to promote production efficiency; and the activity and health of the animal. It has also been suggested that there may be genetic factors that affect methane production. Of these factors, the feed characteristics and level have the most influence.

To describe the methane production by ruminant animals, it is convenient to refer to the portion of feed energy intake that is converted to methane. Higher levels of conversion translate into higher emissions, given constant feed energy intake. Similarly, higher levels of intake translate into higher emissions, given constant conversion. There are, however, interactions between level of intake and conversion to methane, so these values are not independent.

As a result of the various interrelationships among feed characteristics, feed intake, and conversion rates to methane, most well-fed ruminant animals in temperate agriculture systems will convert about 5.5-6.5 percent of their feed energy intake to methane (Johnson et al., 1991). Given

¹ Monogastric animals have a mouth, esophagus, stomach, small intestines, large intestines, pancreas, and liver (Ensminger, 1983). Examples of monogastric animals include swine, dogs, monkeys, and humans.

this range for the rate of methane formation, methane emissions can be estimated based on the feed energy consumed by the animals. Because feed energy intake is related to production level (e.g., weight gain or milk production), the feed energy intake can be estimated for these regions based on production statistics.

The rates of conversion of feed energy to methane for the non-ruminant animals are much lower than those for ruminants. For swine on good quality grain diets about 0.6 percent of feed consumed is converted to methane (Crutzen et al., 1986). For horses, mules, and asses the estimate is about 2.5 percent. While these estimates are also uncertain and likely vary among regions, the global emissions from these species are much smaller than the emissions from ruminant animals. Consequently, the uncertainty in these values does not contribute significantly to the uncertainty in the estimates of total methane emissions from livestock.

DESCRIPTION OF WORKBOOK METHOD

While it is possible to measure methane emissions from cattle directly, it is not practical for preparing an emissions inventory. Given that direct measurements will not be taken, it is appropriate to select a model for estimating emissions factors for individual animal types. Once these factors have been developed, they are multiplied by applicable animal populations to arrive at total emissions for each animal type; total emissions by animal type are summed to arrive at total annual methane emissions.

Given their population and size, cattle account for the majority of methane emissions in the U.S. Additionally, cattle characteristics and emissions vary significantly by region. Therefore, it is important to develop a good model for cattle which takes into account the diversity of cattle types and cattle feeding systems in the U.S. Emissions factors for other animals were developed using a simple functional relationship between feed intake and feed intake released as methane (see Table D6-1). This approach is reasonable given that cattle characteristics of other animals are more or less homogeneous across regions. Therefore, the variability in emissions factors among regions for other animals is much smaller than the variability in emissions factors for cattle.

The emissions factors presented in the Workbook Section were developed using a validated mechanistic model² of rumen digestion and methane production for cattle feeding systems in the U.S. The digestion model estimates the amount of methane formed and emitted as a result of microbial fermentation in the rumen. The digestion model is linked to an animal production model that predicts growth, pregnancy, milk production and other production variables as a function of digestion products developed by the digestion model. The model evaluates the relationships between feed input characteristics and animal outputs including weight gain, lactation, heat production, pregnancy, and methane emissions. The model has been validated for a wide range of feeding conditions encountered in the U.S.; a total of 32 diets were simulated for 8 animal types in 5 regions.

The emissions factors derived using the approach outline above are provided in Tables D6-1 and D6-2, as well as in Workbook Section 6. Given the detailed, U.S.-specific data used to derive these emissions factors, the approach presented in the Workbook Section is likely to be sufficient for most animal types in most regions of the U.S. However, in some states cattle characteristics may

² The mechanistic model is outlined in the U.S. EPA Report to Congress entitled "Anthropogenic Methane Emissions in the United States: Estimates for 1990."

Table D6-1**Enteric Fermentation Emissions Factors for Other Animals (lbs/head/year)**

Animal Type	Feed Intake (MJ/h/day)	Methane Conversion (%)	Emissions Factors (lbs/h/yr)
Sheep	20	6%	17.6
Goats	14	5%	11.0
Swine	38	0.6%	3.3
Horses	110	2.5%	39.6
Mules/Asses	60	2.5%	48.5

Source: Crutzen et al (1986).

Table D6-2**Emissions Factors for U.S. Cattle by Region (lbs/head/yr)****Mechanistic Model vs. IPCC Model**

Animal Type/Region	National Average	
	Mechanistic Model	IPCC Method
Dairy Cattle		
Replacements 0-12 months	43.1	46.9
Replacements 12-24 months	129.4	127.5
Mature Cows	252.1	248.7
Beef Cattle		
Replacements 0-12 months	49.1	51.1
Replacements 12-24 months ^a	143.0	121.5
Mature Cows	146.7	143.9
Weanling System Steers/Heifers ^b	50.8	80.2
Yearling System Steers/Heifers	104.1	113.7
Bulls ^c	220	223.4

^a The IPCC emissions factors for beef replacements 12-24 months, were calculated to reflect the NEg for medium frame heifer calves as cited in NRC (1984).

^b Feed and growth rates for weanlings in the U.S. are different from the rest of the world; the IPCC method does not account for these differences, which could explain the deviant results.

^c The IPCC emissions factors for bulls were calculated to reflect the intake requirements as cited in NRC (1984)

vary significantly from those analyzed by the mechanistic model, from which the emissions factors were derived. In such a case, an alternative approach may be appropriate, such as the method presented in the *IPCC Guidelines for National Greenhouse Gas Inventories: Vol. 2, Reference Manual* (IPCC, 1994). To compare the accuracy of the IPCC model with that of the mechanistic model, emissions estimates were generated for both models using identical inputs. The emission factors derived from each model and used to calculate emission estimates are presented in Table D6-2. As illustrated in the table, the emission factors are similar. The following section presents the IPCC model. For completeness, some discussion of the appropriateness of this method to tropical conditions is provided, although these conditions are not typically found in the U.S.

ALTERNATE METHODOLOGY

The IPCC method for estimating methane emissions from enteric fermentation requires three basic steps:³

- Step 1:** Divide the livestock population into subgroups and characterize each subgroup.
- Step 2:** Estimate emissions factors for each subgroup in terms of kilograms of methane per animal per year. Once these have been determined they may be easily converted to pounds per animal per year.
- Step 3:** Multiply the subgroup emissions factors by the subgroup populations to estimate the subgroup emissions, and sum across subgroups to estimate total emissions.

Step 1: Livestock Populations

To develop precise estimates of emissions, cattle should be divided into categories of relatively homogeneous groups. For each category a representative animal is chosen and characterized for purposes of estimating an emissions factor. Table D6-3 presents a set of recommended representative animal types for cattle. Three main categories, Mature Dairy Cows, Mature Non-Dairy Cattle, and Young Cattle, are recommended as the minimum set of representative types. The sub-categories listed should be used when data are available. In particular, the sub-population of cows providing milk to calves should be identified among non-dairy cattle because the feed intake necessary to support milk production can be substantial.

For each of the representative animal types defined, the following information is required:⁴

- annual average population (number of head);

³ The IPCC method is outlined in the *IPCC Greenhouse Gas Inventory Reference Manual* (IPCC, 1994).

⁴ Data requirements for this model are expressed in metric units. The reason for this being that the energetic relationships presented in the equations were developed for use with metric units. After emissions factors are derived, however, they can be converted to U.S. units by applying the appropriate conversion factors.

- average daily feed intake (megaJoules (MJ) per day and kg per day of dry matter); and
- methane conversion rate (percentage of feed energy converted to methane).

Generally, data on average daily feed intake are not available, particularly for grazing animals. Consequently, the following data should be collected for estimating the feed intake for each representative animal type:

- weight (kg);
- average weight gain per day (kg);⁵
- feeding situation: confined animals; animals grazing on good quality pasture; and animals grazing over very large areas;
- milk production per day (kg/day);⁶
- average amount of work performed per day (hours/day);
- percent of cows that give birth in a year;⁷ and
- feed digestibility (%).⁸

These data should be obtained from state-specific cattle evaluations. Some data, such as weight, weight gain, and milk production, may be available from production statistics. Care should be taken to use the live cattle weights, as contrasted with slaughter weights.

Data on methane conversion rates are also not generally available. As a rule of thumb, a 6 percent conversion rate (± 0.5 percent) is recommended for all cattle, except feedlot cattle consuming diets with a large quantity of grain⁹. For feedlot cattle on high grain diets a rate of 4 percent (± 0.5 percent) is recommended. In circumstances where good feed resources are available (*i.e.*, high digestibility and high energy value) the lower bounds of these ranges can be used. When poorer feed resources are available, the higher bounds are more appropriate.

⁵ This may be assumed to be zero for mature animals.

⁶ Milk production is required for dairy cows and non-dairy cows providing milk to calves.

⁷ This is only relevant for mature female cows.

⁸ Feed digestibility is defined as the proportion of energy in the feed that is not excreted in the feces. Digestibility is commonly expressed as a percentage (%). Common ranges for feed digestibility for cattle are 50% to 60% for crop by-products and rangelands; 60% to 70% for good pastures, good preserved forages, and grain-supplemented forage-based diets; and 75% to 85% for grain-based diets fed in feedlots.

⁹ It should be noted that this rule of thumb applies only to the U.S.

Table D6-3
Recommended Representative Cattle Types

Main Categories	Sub-Categories
Mature Dairy Cows	Used principally for commercial milk production
Mature Non-Dairy Cattle	<p>Mature Females:</p> <ul style="list-style-type: none"> -- Beef Cows: used principally for producing beef steers and heifers -- Multiple-Use Cows: used for milk production, draft power, and other uses <p>Mature Males:</p> <ul style="list-style-type: none"> -- Breeding Bulls: used principally for breeding purposes -- Draft Bullocks: used principally for draft power
Young Cattle	<p>Pre-Weaned Calves</p> <p>Growing Heifers, Steers/Bullocks and Bulls</p> <p>Feedlot-Fed Steers and Heifers on High-Grain Diets</p>

The above rule of thumb is a rough guide based on the general feed characteristics and production practices found in states. State-specific exceptions to these general rules of thumb should be taken into consideration as necessary based on detailed data from cattle experts.

Step 2: Emissions Factors

The emissions factors for each category of cattle are estimated based on the feed intake and methane conversion rate for the category. Feed intake is estimated based on the feed energy requirements of the representative animals, subject to feed-intake limitations. The net energy system described in NRC (1984 and 1989) is recommended as the starting point for the estimates.

The net energy system specifies the amount of feed energy required for the physiological functions of cattle, including maintenance, growth, and lactation. Feed energy requirements for work have also been estimated. Energy requirements for pregnancy have also been added for the portion of cows that give birth in each year. The following information is required to estimate feed energy intakes:

- *Maintenance*

Maintenance refers to the apparent feed energy required to keep the animal in energy equilibrium, *i.e.*, there is no gain or loss of energy in the body tissues (Jurgens, 1988). For cattle, net energy for maintenance (NE_m) has been estimated to be a function of the weight of the animal raised to the 0.75 power (NRC, 1984):

$$NE_m \text{ (MJ/day)} = 0.322 \times (\text{weight in kg})^{0.75}$$

NRC (1989) recommends that lactating dairy cows be allowed a slightly higher maintenance allowance:

$$NE_m \text{ (MJ/day)} = 0.335 \times (\text{weight in kg})^{0.75} \quad \{\text{dairy cows}\} \quad (1^*)$$

Additional energy is required for animals to obtain their food. Grazing animals require more energy for this activity than do stall-fed animals. The following energy requirements are added for this activity based on their feeding situation:

- Confined animals (pens and stalls): no additional NE_m ;
- Animals grazing good quality pasture: 17 percent of NE_m ; and
- Animals grazing over very large areas: 37 percent of NE_m .

Growth

The energy requirements for growth can be estimated as a function of the weight of the animal and the rate of weight gain. NRC (1989) presents formulae for large- and small-frame males and females, the estimates from which vary by about ± 25 percent. The equation for large-frame females is recommended, which is about the average for the four types:

$$NE_g \text{ (MJ/day)} = 4.18 \times (0.035 W^{0.75} \times WG^{1.119} + WG) \quad (2)$$

where:

- W = animal weight in kilograms (kg); and
WG = weight gain in kg per day.

The relationships for NE_g were developed for temperate agriculture conditions, and may over-estimate energy requirements for tropical conditions, particularly for draft animals that may have a lower fat content in their weight gain (Graham, 1985). However, no data are available for improving the estimates at this time.

Lactation

Net energy for lactation has been expressed as a function of the amount of milk produced and its fat content (NRC, 1989):

$$NE_l \text{ (MJ/day)} = \text{kg of milk/day} \times (1.47 + 0.40 \times \text{Fat \%}) \quad (3)$$

At 4.0 percent fat, the NE_l in MJ/day is about $3.1 \text{ MJ/kg of milk} \times \text{kg of milk/day}$.

Draft Power

Various authors have summarized the energy intake requirements for providing draft power (e.g., Lawrence, 1985; Bamualim and Kartiarso, 1985; and Ibrahim, 1985). The strenuousness of the work performed by the animal influences the energy requirements, and consequently a wide range of energy requirements have been estimated. The values by Bamualim and Kartiarso show that about 10 percent of NE_m requirements are required per hour of typical work for draft animals. This value is used as follows:

$$NE_{\text{draft}} \text{ (MJ/day)} = 0.10 \times NE_m \times \text{hours of work per day} \quad (4)$$

• *Pregnancy*

Daily energy requirements for pregnancy are presented in NRC (1984). Integrating these requirements over a 281-day gestation period yields the following equation:

$$NE_{\text{pregnancy}} (\text{MJ}/281\text{-day period}) = 28 \times \text{calf birth weight in kg} \quad (5)$$

The following equation can be used to estimate the approximate calf birth weight as a function of the cow's weight:¹⁰

$$\text{Calf birth weight (kg)} = 0.266 \times (\text{cow weight in kg})^{0.79} \quad (6)$$

Manipulating equations 5 and 6, in conjunction with equation 1, shows that the NE required for pregnancy is about 7.5 percent of NE_m for the range of cow sizes considered in this analysis. Therefore, a factor of 7.5 percent of NE_m is added to account for the energy required for pregnancy for the portion of cows giving birth each year.

Based on these equations, each of the net energy components for each of the cattle categories can be estimated from the data collected in Step 1: weight in kilograms; feeding situation; weight gain per day in kilograms; milk production in kilograms of 4 percent fat-corrected milk; number of hours of work performed per day; and portion that give birth.

These net energy requirements must be translated into gross energy intakes. Also, by estimating the gross energy intake, the net energy estimates can be checked for reasonableness against expected ranges of feed intake as a percentage of animal weight. To estimate gross energy intake, the relationship between the net energy values and gross energy values of different feeds must be considered. This relationship can be summarized briefly as follows:

Digestible Energy	= Gross Energy - Fecal Losses
Metabolizable Energy	= Digestible Energy - Urinary and Combustible Gas Losses
Net Energy	= Metabolizable Energy - Heat Increment
<hr/>	
Net Energy	= Gross Energy - Fecal Losses - Urinary and Combustible Gas Losses - Heat Increment

The quantitative relationship among these energy values varies among feed types. Additionally, the values depend on how the feeds are prepared and fed, and the level at which they are fed. For purposes of this method, simplified assumptions are used to derive a relationship between net energy and digestible energy that is reasonably representative for the range of diets typically fed to cattle. Gross energy intake is then estimated using this relationship and the digestibility data collected in Step 1.

Given the digestibility of the feed (defined in Step 1), a general relationship between digestible energy and metabolizable energy can be used as follows (NRC, 1984):

¹⁰ This species-specific equation from Robbins and Robbins (1979) was adjusted to the mean cow and calf weight of a typical beef breed of cattle. This adjustment increases the coefficient in the equation from 0.214 to 0.266.

$$\text{Metabolizable Energy (ME)} = 0.82 \times \text{Digestible Energy (DE)} \quad (7)$$

Equation 7 is a simplified relationship; larger (smaller) methane conversion rates would tend to reduce (increase) the coefficient to values below (above) 0.82.

NRC (1984) presents separate quantitative relationships between metabolizable energy and net energy used for growth versus net energy used for other functions. Using equation 7, the NRC relationships can be re-arranged to quantify the ratio of NE to DE, as follows:

$$\text{NE/DE} = 1.123 - 4.092 \times 10^{-3} \times \text{DE\%} + 1.126 \times 10^{-5} \times (\text{DE\%})^2 - 25.4/\text{DE\%} \quad (8)$$

$$\text{NE}_g/\text{DE} = 1.164 - 5.160 \times 10^{-3} \times \text{DE\%} + 1.308 \times 10^{-5} \times (\text{DE\%})^2 - 37.4/\text{DE\%} \quad (9)$$

where:

NE/DE = the ratio of net energy consumed for maintenance, lactation, work and pregnancy to digestible energy consumed;

NE_g/DE = the ratio of net energy consumed for growth to digestible energy consumed; and

DE\% = digestible energy as percentage of gross energy, expressed in percent (e.g., 65 percent).

Because the NRC (1984) relationships were developed based on diets with relatively high digestibilities (generally above 65 percent), they may not be appropriate for the relatively low digestibility diets that are commonly found in tropical livestock systems. In particular, the non-linear nature of the relationships could bias the estimates of feed intake upward for low-digestibility feeds. An upward bias in feed intake would lead to an upward bias in emissions estimates.

Based on a review of other energy systems (e.g., ARC, 1980), a linear relationship between digestible energy and net energy was derived for digestibilities below 65 percent as follows (see Appendix C):

$$\text{NE/DE} = 0.298 + 0.00335 \times \text{DE\%} \quad (10)$$

$$\text{NE}_g/\text{DE} = -0.036 + 0.00535 \times \text{DE\%} \quad (11)$$

Given the estimates for feed digestibility (from Step 1) and equations 8 through 11, the gross energy intake (GE in MJ/day) can be estimated as follows:

$$\text{GE} = [(\text{NE}_m + \text{NE}_{\text{feed}} + \text{NE}_l + \text{NE}_w + \text{NE}_p) / \{\text{NE/DE}\} + (\text{NE}_g / \{\text{NE}_g/\text{DE}\})] / (\text{DE\%}/100) \quad (12)$$

where:

$\{\text{NE/DE}\}$ is computed from equation 8 for digestibility greater than 65 percent and from equation 10 for digestibility less than or equal to 65 percent;

$\{\text{NE}_g/\text{DE}\}$ is computed from equation 9 for digestibility greater than 65 percent and from equation 11 for digestibility less than or equal to 65 percent; and

DE\% is digestibility in percent (e.g., 60 percent).

To check the estimate of daily gross energy intake from equation 12, the estimate can be converted in daily intake in kilograms by dividing by 18.45 MJ/kg. This estimate of intake in kilograms should generally be between 1.5 percent and 3.0 percent of the animal's weight.

Using equation 12, Gibbs and Johnson (1993) found that the intake estimates are consistent with expected intakes as a percent of body weight and previously published values. For example, the intake estimate for Indian cattle is the equivalent of about 10,000 MJ per year of metabolizable energy (ME). Winrock (1978) estimates the average ME requirements for Indian cattle at 10,600 MJ per year. Similarly, the ME values implied for U.S. dairy and beef cows are 58,000 MJ and 31,000 MJ per year, respectively, which are similar to estimates of 62,000 MJ and 31,700 MJ derived in U.S. EPA (1993). Consequently, for a diverse set of conditions, the intake estimates correspond to reasonably expected ranges from previously published estimates.

To estimate the emissions factor for each cattle type, the feed intake is multiplied by the methane conversion rate (from Step 1) as follows:

$$\text{Emissions (kg/yr)} = \text{Intake (MJ/day)} \times Y_m \times 365 \text{ days} / 55.65 \text{ MJ/kg of methane} \quad (13)$$

where Y_m is the methane conversion rate expressed in decimal form (such as 0.06 for 6 percent). The result of this step of the method is an emissions factor for each cattle type defined in Step 1.

Step 3: Total Emissions

To estimate total emissions the selected emission factors are multiplied by the associated animal population and summed.

DATA SOURCES

Unpublished information is available from practitioners in individual states. Departments within each state responsible for conducting agricultural research and that oversee the agriculture sector should be consulted. State animal populations can be found in the *Census of Agriculture, Volume 1: Geographic Area Series*, published by the Bureau of the Census. Also, the USDA can produce state by state inventories on domesticated animal populations.

Data on feed characteristics have been compiled in NRC (1989), ARC (1980), and Jurgens (1988). These, and similar, sources may be consulted to evaluate the feed consumption of specific categories of ruminant animals.

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DISCUSSION 7

METHANE EMISSIONS FROM MANURE MANAGEMENT

OVERVIEW

Manure decomposition is a process in which microorganisms derive energy and material for cellular growth by metabolizing organic material in the manure. When decomposition occurs without oxygen present (anaerobically), methane is an end-product of the process. This section will describe the fundamentals of anaerobic decomposition; the methane producing capacity of livestock manure; and the factors that influence methane production from livestock manure.¹

The Fundamentals of Anaerobic Decomposition

Livestock manure is primarily composed of organic material and water. Under anaerobic conditions, the organic material is decomposed by anaerobic and facultative (living in the presence or absence of oxygen) bacteria. The end products of anaerobic decomposition are methane, carbon dioxide, and stabilized organic material.

The anaerobic decomposition process can be represented in three stages: hydrolytic; acid forming; and methanogenic. Carbohydrates decomposition can be illustrated as follows:²

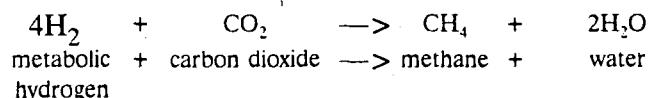
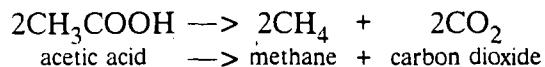
- **Stage 1: Hydrolytic.** In the first stage, complex organic materials in the manure substrate are broken down through the hydrolytic action of enzymes. Enzymes are proteins formed by living cells that act as catalysts in metabolic reactions. The amount and rate of breakdown can vary substantially and depend on the enzymes present, the characteristics of the manure, and environmental factors such as pH and temperature.
- **Stage 2: Acid Forming.** Anaerobic and facultative bacteria reduce (ferment) the simple sugars produced in Stage 1 to simple organic acids. Acetic acid is the primary product of the breakdown of carbohydrates, though other organic acids such as propionic acid and butyric acid can be formed. In addition, metabolic hydrogen and carbon dioxide are produced. With acetic acid as an end product, the breakdown of a simple sugar molecule (glucose) in Stage 2 can be represented as:



¹ Background information on animal wastes is taken from Safley et al. (1992).

² This discussion focuses on the decomposition of carbohydrates because carbohydrate decomposition accounts for the majority of the methane produced from livestock manure and because the process of methane production from the decomposition of carbohydrates is best understood. By weight, the volatile solids portion of cattle and swine manure is approximately 40 percent carbohydrate, 15 to 20 percent protein, and up to 10 to 20 percent fat with the remainder composed of other material (Hrubant, Rhodes, and Sloneker, 1978).

- Stage 3: Methanogenic. Methane producing bacteria (methanogens) convert the simple organic acids, metabolic hydrogen, and carbon dioxide from Stage 2 into methane and carbon dioxide. Methanogens are strict anaerobes and cannot tolerate the presence of molecular oxygen. Methanogens multiply slowly and are very sensitive to temperature, pH, and substrate composition. With acetic acid, metabolic hydrogen and carbon dioxide as substrate, the reactions producing methane can be expressed as:



Methane Producing Capacity of Livestock Manure

In general, livestock manure is highly conducive to methane generation due to its high organic content and the presence of useful bacteria. However, the specific methane producing capacity of livestock manure depends on the specific composition of the manure which in turn depends on the composition and digestibility of the animal diet. The greater the energy content and digestibility of the feed, the greater the methane producing capacity of the resulting manure. For example, feedlot cattle eating a high energy grain diet produce a highly biodegradable manure with a high methane producing capacity. Range cattle eating a low energy forage diet produce a less biodegradable manure with only half the methane producing capacity of feedlot cattle manure.

In principal, the ultimate methane producing capacity of a quantity of manure can be predicted from the gross elemental composition of the manure. In practice, however, insufficient information exists to implement this approach and the methane producing capacity is determined through direct laboratory measurement. The methane producing capacity of livestock manure is generally expressed in terms of the quantity of methane that can be produced per kilogram of volatile solids (VS) in the manure.³ This quantity is commonly referred to as B_0 with units of cubic feet of methane (CH_4) per pound VS ($\text{ft}^3 \text{CH}_4 / \text{lb VS}$). Representative B_0 values for a number of livestock manure types are presented later in this discussion.

Factors Influencing Methane Production

While a particular quantity of manure may have a certain potential to produce methane based on its volatile solids content, the management of the livestock manure and the environment in which the manure is managed are the major factors influencing the amount of methane actually produced during manure decomposition.

The characteristics of the manure management systems and environmental conditions can be expressed in a methane conversion factor (MCF) which represents the extent to which the potential

³ Volatile solids (VS) are defined as the organic fraction of the total solids (TS) in manure that will oxidize and be driven off as gas at a temperature of 1,112°F. Total solids (TS) are defined as the material that remains after evaporation of water at a temperature between 217° and 221°C.

for emitting methane is actually realized. Manure systems and climate conditions that promote methane production will have an MCF near 1 and manure systems and climate conditions that do not promote methane production will have an MCF near 0. The primary characteristics determining the MCF are:

Livestock Manure Management System Factors

- *Contact with Oxygen.* Under aerobic conditions where oxygen is in contact with the manure, there is no potential for methane production.
- *Water Content.* Liquid based systems promote an oxygen-free environment and anaerobic decomposition. In addition, water is required for bacterial cell production and metabolism and acts as a buffer to stabilize pH. Moist conditions increase the potential for methane production.
- *pH.* Methane producing bacteria are sensitive to changes in pH. The optimal pH is near 7.0 but methane can be produced in a range between 6.6 and 8.0.
- *Nutrients.* Bacterial growth depends on the availability of nutrients such as nitrogen, phosphorus, and sulfur. Deficiency in one or more of these nutrients will inhibit bacterial growth and methane formation. Animal diets typically contain sufficient nutrients to sustain bacterial growth. Therefore, nutrient availability is not a limiting factor in methane production under most circumstances.

Climate Factors

- *Temperature.* Methanogenesis in livestock manure has been observed between 39° F and 167° F. Temperature is one of the major factors affecting the growth of the bacteria responsible for methane formation (Chawla, 1986). The rate of methane production generally increases with rising temperature.
- *Moisture.* For non-liquid based manure systems, the moisture content of the manure is determined by rainfall and humidity. The moisture content of the manure will determine the rate of bacterial growth and decomposition. Moist conditions promote methane production.

These factors can be combined into the following expression for estimating realized methane emissions from livestock manure:

$$\text{Realized Emissions} = B_0 \cdot \text{MCF} \quad (7.1)$$

where B_0 = the maximum methane producing capacity of the manure determined by animal type and diet ($\text{ft}^3 \text{ CH}_4 / \text{lb VS}$).

MCF = Methane Conversion Factor (MCF) that represents the extent to which the B_0 is realized for a given livestock manure management system and environmental conditions. Note: $0 \leq \text{MCF} \leq 1$.

DESCRIPTION OF WORKBOOK METHOD

Methane emissions from livestock manure depend on the type of manure, the characteristics of the manure management system, and the climatic conditions in which the manure decomposes. While limited data are available on which to base emission estimates, a study recently prepared for the U.S. EPA provides an adequate basis for making initial estimates (Safley et al., 1992). Additional analysis is ongoing to provide additional data for estimating these emissions.

Based on the Safley et al. (1992) approach, emission estimates are developed by:

- identifying the manure management systems in use in the United States and their methane producing potential;
- estimating the amount and type of manure managed by each system; and
- estimating emissions by multiplying the amount of manure managed in each system by the estimated emission rate per unit of manure in the system.

Information can be obtained from a variety of sources, including:

- the U.S. Census of Agriculture;
- USDA agriculture statistics;
- livestock manure management experts throughout the U.S.; and
- scientific literature.

Total emissions will equal the quantity of volatile solids managed in each system times emissions per kilogram of volatile solids (VS) for that system. Safley et al. (1992) used the following procedure to estimate total emissions:

- Collect data on: (1) the populations of the major animal types in each state of the U.S. (N); and (2) their typical animal mass (TAM).
- Collect information on the characteristics of the manure produced by each of the animal populations in each state, including: (1) the amount of volatile solids (VS) produced; and (2) the methane producing capacity (B_0) of the manure. The amount of volatile solids produced depends on the number of animals in the state and their mass:

$$VS_{ik} = N_{ik} \cdot TAM_i \cdot vs_i \quad (7.2)$$

where:

- N_{ik} = number of animals of type i in state k .
 TAM_i = typical animal mass in pounds of animal i ; and
 vs_i = the average annual volatile solids production per unit of animal mass (pounds per pound) for animal i .

- Identify the livestock manure management systems used in each state and the percentage of manure managed by each (WS%).
- Estimate the methane producing potential (MCF) of each manure management system in each state based on the average monthly temperature in the state.
- Estimate methane emissions for each animal and manure system in each state (TM) by multiplying the amount of volatile solids (VS) produced by the methane producing capacity of the manure (B_{o_i}) times the methane producing potential (MCF) of the manure system in each state.

$$TM_{ijk} = VS_{ik} \cdot B_{oi} \cdot MCF_{jk} \cdot WS\%_{ijk} \quad (7.3)$$

where:

VS_{ik}	=	total volatile solids produced (lbs/yr) for animal i in state k ;
B_{oi}	=	maximum methane producing capacity per pound of VS for animal i ;
MCF_{jk}	=	methane conversion factor for each manure system j in state k ;
$WS\%_{ijk}$	=	percent of animal i 's manure managed in manure system j in state k .

- Estimate total annual methane emissions (TM) for animal i as the sum of annual emissions over all applicable manure management systems j :

$$TM_i = \sum_j TM_{ij} \quad (7.4)$$

- Estimate total annual methane emissions from all animals (TM) as the sum over all animal types i as follows:

$$TM = \sum_i TM_i \quad (7.5)$$

These equations show that methane emissions are driven by four main factors: the quantity of VS produced; the B_{oi} values for the manure; the MCFs for the manure management systems; and the portion of the manure handled by each manure management system (WS%). The following sections describe the data collected to implement this method.

Volatile Solids Production (VS)

Methane emissions from livestock manure are directly related to the amount of volatile solids (VS) produced. The data required to estimate total VS production are the number of animals (N_i), average size (TAM_i), and average VS production per unit of animal size (vs_i).

In the U.S., considerable data are available to allow the populations of animals to be analyzed by: species, production system, and (for cattle) age. Six main categories of animals were defined:

feedlot beef cattle;⁴ other beef cattle; dairy cattle; swine; poultry; and other. These main categories were further divided into 20 subcategories. For each subcategory, VS production was estimated using data on: the animal population; the typical animal mass (TAM); and the VS production per unit of animal mass. Table D7-1 lists the data obtained for the 20 subcategories.

Maximum Methane Producing Capacity (B_0)

The maximum amount of methane that can be produced per pound of VS (B_0) varies by animal type and diet. Measured B_0 values for beef manure range from 2.72 cubic feet of methane per pound of VS (ft³/lb-VS) for a corn silage diet to 5.29 ft³/lb-VS for a corn-based high energy diet that is typical of feedlots. Table D7-2 summarizes these values.

Appropriate B_0 values were selected depending on the typical diet of each animal type and category. For animal types without B_0 measurements, the B_0 was estimated based on similarities with other animals and the authors' experience. Ruminants for which there were no literature values were assumed generally to have the same values as cattle, except for sheep, which were assumed to have B_0 values 10 percent higher than cattle (Jain et al. 1981). Table D7-3 lists the values selected for the analysis.

Manure Management Systems Definitions

A variety of manure management practices are in use throughout the U.S. The following is a brief description of the major livestock manure management systems in use.

PASTURE/RANGE	Animals that are grazing on pasture are not on any true manure handling system. The manure from these animals is allowed to lie as is, and is not managed at all.
DAILY SPREAD	With the daily spread system the manure is collected in solid form, with or without bedding, by some means such as scraping. The collected manure is stored until applied to fields on a regular basis.
SOLID STORAGE	In a solid storage system the solid manure is collected as in the daily spread system, but this collected manure is stored in bulk for a long period of time (months) before any disposal.
DRYLOT	In dry climates animals may be kept on unpaved feedlots where the manure is allowed to dry until it is periodically removed. Upon removal the manure may be spread on fields.
DEEP PIT STACKS	With caged layers the manure may be allowed to collect in solid form in deep pits (several feet deep) below the cages. The manure in the pits may only be removed once a year. This manure generally stays dry.

⁴ Feedlot cattle are animals fed a ration of grain, silage, hay and protein supplements for the slaughter market (ASB, 1991).

Table D7-1
U.S. Animal Populations, Average Size, and VS Production

Animal Type		Population ^{A,B} N _i	Typical Animal Mass (TAM _i) ^C lbs	Volatile Solids (vs.) lbs VS/lb animal mass/yr
Feedlot Beef Cattle	Steers	7,367,000	915	2.6
	Heifers	3,785,000	915	2.6
	Cows/Other	87,000	1102	2.6
	Total	11,239,000		
Other Beef Cattle	Calves	20,248,000	397	2.6
	Heifers	13,547,000	794	2.6
	Steers	8,430,000	794	2.6
	Cows	33,583,000	1102	2.6
	Bulls	2,221,000	1587	2.6
	Total	78,029,000		
Dairy Cattle	Heifers	4,199,000	903	3.65
	Cows	10,217,000	1345	3.65
	Total	14,416,000		
Swine	Market	48,259,000	101	3.1
	Breeding	7,040,000	399	3.1
	Total	55,299,000		
Poultry ^C	Layers	355,469,000	3.5	4.4
	Broilers	951,914,000	1.5	6.2
	Ducks	7,000,000	3.1	6.75
	Turkeys	53,783,000	7.5	3.32
Other	Sheep	10,639,000	154	3.36
	Goats	2,396,000	141	3.48
	Donkeys	4,000	661	3.65
	Horses and Mules	2,405,000	992	3.65

A Population data for animals except goats and horses from ASB (1989a-f). Goat and horse population data from Bureau of Census (1987). Population data as of January 1, 1988 for cattle, poultry, and sheep and as of December 1, 1987 for swine, goats, and horses.
 B Broiler/turkey populations estimated yearly based on number of flocks per year (North 1978; Carter 1989).
 C Source: Taiganides and Stroshine (1971).
 D Source: ASAE (1988).

Table D7-2
Maximum Methane Producing Capacity for U.S. Livestock Manure

Animal Type	Diet	B ₀ (ft ³ CH ₄ /lb-VS)	Reference
Beef	7% corn silage, 87.6% corn	4.65	Hashimoto et al. (1981)
Beef	Corn-based high energy	5.29	Hashimoto et al. (1981)
Beef	91.5% corn silage, 0% corn	2.72	Hashimoto et al. (1981)
Beef		3.68	Hill (1984)
Beef		5.29	Chen, et al. (1980)
Dairy	58-68% silage	3.84	Morris (1976)
Dairy	72% roughage	2.72	Bryant et al. (1976)
Dairy		2.24	Hill (1984)
Dairy	Roughage, poor quality	1.60	Chen, et al. (1988)
Horse		5.29	Ghosh (1984)
Poultry	Grain-based ration	6.25	Hill (1982)
Poultry		5.77	Hill (1984)
Poultry		3.84	Webb & Hawkes (1985)
Poultry		3.84	Hawkes & Young (1980)
Swine	Barley-based ration	5.77	Summers & Bousfield (1980)
Swine	Corn-based high energy	7.69	Hashimoto (1984)
Swine		5.13	Hill (1984)
Swine	Corn-based high energy	8.33	Kroeker et al. (1984)
Swine	Corn-based high energy	7.69	Stevens & Schulte (1979)
Swine	Corn-based high energy	7.53	Chen (1983)
Swine	Corn-based high energy	7.05	Iannotti et al. (1979)
Swine	Corn-based high energy	7.21	Fischer et al. (1975)

Table D7-3
Maximum Methane Producing Capacity Adopted For U.S. Estimates

Animal Type, Category	Maximum Potential Emissions (B ₀)	Reference
Cattle:	Beef in Feedlots	5.29
	Beef Not in Feedlots	2.72
	Dairy	3.84
Swine:	Breeder	5.77
	Market	7.53
Poultry:	Layers	5.45
	Broilers	4.81
	Turkeys	4.81
Sheep:	In Feedlots	5.77
	Not in Feedlots	3.04
Goats:		2.72
Horses and Mules:		5.29

LITTER	Broilers and young turkeys may be grown on beds of litter such as shavings, sawdust, or peanut hulls, and the manure/litter pack is removed periodically between flocks. This manure will not generally be as dry as with deep pits, but will still be in solid form.
PADDOCK	Horses are frequently kept in paddocks where they are confined to a limited area, but not entirely confined to their stalls. This manure will be essentially the same as manure on pasture or drylot.
LIQUID/SLURRY	These systems are generally characterized by large concrete lined tanks built into the ground. Manure is stored in the tank for six or more months until it can be applied to fields. To facilitate handling as a liquid, water usually must be added to the manure, reducing its total solids concentration to less than 12 percent. Slurry systems may or may not require addition of water.
ANAEROBIC LAGOON	Anaerobic lagoon systems are generally characterized by automated flush systems that use water to transport the manure to treatment lagoons that are usually greater than six feet deep. The manure resides in the lagoon for periods ranging from 30 days to over 200 days depending on the lagoon design and other local conditions. The water from the lagoon is often recycled as flush water. Periodically the lagoon water may be used for irrigation on fields with the treated manure providing fertilizer value.
PIT STORAGE	Liquid swine manure may be stored in a pit while awaiting final disposal. The pits are often constructed beneath the swine building. The length of storage time varies, and for this analysis is divided into two categories: less than one month or greater than one month.

Methane Conversion Factors (MCFs)

The extent to which the maximum methane producing capacity (B_0) is realized for a given livestock manure management system and environmental conditions is defined as the Methane Conversion Factor (MCF) for the manure system. For example, a manure system that produces no methane emissions will have an MCF of 0. A manure system that achieves full potential methane emissions would have an MCF of 1.

To assess the MCF values for a wide range of livestock manure management systems, two broad classifications of livestock manure handling systems can be defined based on the total solids content of the manure:

- Solid systems have a total solids content greater than about 20 percent.
- Liquid/slurry systems have a total solids content less than 20 percent.

Manure as excreted may have a total solids content from 9 to 30 percent (Taiganides 1987). This solids content may be modified by adding an absorbent bedding material to increase the total solids content for easier handling. Alternatively, water may be added to lower the total solids to allow for liquid transport and handling.

These classifications of systems are particularly important to the potential for methane production from the manure. Liquid and slurry systems will typically cause anaerobic conditions to develop, which result in methane production. Solid systems promote conditions that limit methane production even if anaerobic conditions may exist.

Safley et al. (1992) reviewed the literature to investigate the appropriate range of MCF values for U.S. manure management systems. Although some data were available, MCF values were estimated for many systems. To improve the MCF estimates, the U.S. Environmental Protection Agency is sponsoring analysis to better estimate the MCF for several key livestock manure systems. Preliminary findings from this analysis indicate that:

- The estimated MCF value of *dry in situ* pasture, range, paddock, and solid storage manure is 1 to 2 percent. The estimated MCF for drylot manure is 1 to 5 percent. However, the analysis has not yet considered the effect of moisture or emissions that may result when the manure is washed into streams, rivers, and lakes or incorporated into the soil (Hashimoto 1992).
- The MCF value liquid/slurry and pit storage varies greatly by temperature and is on the order of 10 percent at 50°F to 65 percent at 86°F (Hashimoto 1992).
- The MCF value for daily spread is less than 1 percent (Hashimoto 1992).
- The MCF value for anaerobic lagoons is on the order of 90 percent. This estimate is based on continuous methane measurements taken over a two and one-half year period at a North Carolina dairy farm (Safley 1991).

The MCF values for each system are listed in Table D7-4. The MCF for an individual state will depend on the average monthly temperature and are calculated by:

- estimating the average monthly temperature in each climate division;⁵
- estimating the MCF value for each month using the average temperature data and the MCF values listed in Table D7-4;
- estimating the annual MCF by averaging the monthly division estimates; and
- estimating the state-wide MCF by weighting the average MCF for each division by the fraction of the state's dairy population represented in each division.⁶

Table D7-5 summarizes the MCF estimates for each state.

⁵ The average temperature in each climate division of each state was calculated for the normal period of 1951 to 1980 using the National Climatic Data Center (NCDC) time-bias corrected Historical Climatological Series Divisional Data (NCDC 1991).

⁶ The dairy population in each climate division were estimated using the dairy population in each county (Bureau of the Census 1987) and detailed county and climate division maps (NCDC 1991). Using the dairy population as a weighting factor may slightly over or underestimate the MCFs for other livestock populations.

Table D7-4**Methane Conversion Factors for U.S. Livestock Manure Systems**

MCFs based on laboratory measurement	MCF at 30°C	MCF at 20°C	MCF at 10°C
Pasture, Range, Paddocks ^A	2 %	1.5 %	1 %
Liquid/Slurry ^A	65 %	35 %	10 %
Pit Storage < 30 days ^A	33 %	18 %	5 %
Pit Storage > 30 days ^A	65 %	35 %	10 %
Drylot ^B	5 %	1.5 %	1 %
Solid Storage ^A	2 %	1.5 %	1 %
Daily Spread ^A	1 %	0.5 %	0.1 %
MCF measured by long term field monitoring		Average Annual MCF	
Anaerobic Lagoons ^C		90 %	
MCFs estimated by Safley et al.		Average Annual MCF	
Litter ^D		10 %	
Deep Pit Stacking ^D		5 %	

A Hashimoto (1992)
 B Based on Hashimoto (1992).
 C Safley et al. (1992) and Safley and Westerman (1992).
 D Safley et al. (1992).

Table D7-5
Methane Conversion Factors for U.S. Livestock Manure Systems

State	Pasture, Range & Paddocks	Drylot	Solid Storage	Daily Spread	Liquid/ Slurry
Alabama	1.4%	1.9%	1.4%	0.4%	29.0%
Arizona	1.4%	1.9%	1.4%	0.4%	28.9%
Arkansas	1.3%	1.8%	1.3%	0.4%	27.6%
California	1.2%	1.4%	1.2%	0.3%	21.9%
Colorado	0.9%	1.0%	0.9%	0.2%	18.2%
Connecticut	0.9%	1.0%	0.9%	0.2%	18.5%
Delaware	1.2%	1.4%	1.2%	0.3%	22.6%
Florida	1.5%	2.4%	1.5%	0.6%	38.6%
Georgia	1.4%	1.8%	1.4%	0.4%	29.0%
Idaho	0.8%	0.8%	0.8%	0.2%	15.5%
Illinois	1.1%	1.3%	1.1%	0.3%	22.8%
Indiana	1.0%	1.2%	1.0%	0.3%	21.5%
Iowa	0.9%	1.1%	0.9%	0.2%	20.7%
Kansas	1.1%	1.5%	1.1%	0.3%	24.7%
Kentucky	1.2%	1.5%	1.2%	0.3%	23.8%
Louisiana	1.4%	2.1%	1.4%	0.5%	32.5%
Maine	0.8%	0.8%	0.8%	0.2%	15.5%
Maryland	1.1%	1.2%	1.1%	0.3%	21.0%
Massachusetts	0.9%	1.0%	0.9%	0.2%	18.1%
Michigan	0.8%	0.9%	0.8%	0.2%	17.0%
Minnesota	0.8%	0.8%	0.8%	0.2%	18.0%
Mississippi	1.4%	1.9%	1.4%	0.4%	29.3%
Missouri	1.1%	1.4%	1.1%	0.3%	24.1%
Montana	0.7%	0.8%	0.7%	0.2%	15.8%
Nebraska	1.0%	1.1%	1.0%	0.2%	20.8%
Nevada	1.2%	1.4%	1.2%	0.3%	22.1%
New Hampshire	0.8%	0.8%	0.8%	0.2%	16.3%
New Jersey	1.0%	1.1%	1.0%	0.3%	20.6%
New Mexico	1.2%	1.3%	1.2%	0.3%	21.3%
New York	0.9%	0.9%	0.9%	0.2%	18.1%
North Carolina	1.3%	1.5%	1.3%	0.3%	24.5%
North Dakota	0.7%	0.7%	0.7%	0.2%	16.8%
Ohio	1.0%	1.1%	1.0%	0.2%	20.2%
Oklahoma	1.4%	1.9%	1.4%	0.4%	28.7%
Oregon	1.1%	1.1%	1.1%	0.2%	16.2%
Pennsylvania	0.9%	1.0%	0.9%	0.2%	18.7%
Rhode Island	1.0%	1.1%	1.0%	0.2%	18.7%
South Carolina	1.3%	1.7%	1.3%	0.4%	27.3%
South Dakota	0.8%	0.9%	0.8%	0.2%	19.1%
Tennessee	1.3%	1.6%	1.3%	0.3%	24.8%
Texas	1.4%	2.1%	1.4%	0.5%	31.7%
Utah	0.9%	1.0%	0.9%	0.2%	17.4%
Vermont	0.8%	0.8%	0.8%	0.2%	16.6%
Virginia	1.2%	1.4%	1.2%	0.3%	22.5%
Washington	1.0%	1.0%	1.0%	0.2%	15.5%
West Virginia	1.2%	1.3%	1.2%	0.3%	21.4%
Wisconsin	0.8%	0.8%	0.8%	0.2%	17.0%
Wyoming	0.8%	0.8%	0.8%	0.2%	15.9%

Other Systems: Pit Storage for less than 30 days is assumed to have an MCF equal to 50% of the MCF for Liquid/Slurry. Pit Storage for more than 30 days is assumed to have an MCF equal to liquid/slurry. Anaerobic lagoons are assumed to have an MCF of 90%; litter and deep pit stacks an MCF of 10%.

Livestock Manure Management System Usage (WS%)

Livestock manure management system usage in the United States was determined by obtaining information from Extension Service personnel in each state. The U.S. was divided into eleven geographic regions based on similarities of climate and livestock production as shown in Table D7-6. For states that did not provide information, the regional average manure system usage was assumed. Some states did not give data for all animal types and a regional average was used in these cases.

Table D7-7 lists the percentage of manure managed by the major systems in the United States. The important manure management characteristics in the U.S. are:

- Approximately one-third of dairy manure is managed as a liquid and approximately one-third is spread directly to cropland.
- Seventy-five percent of swine manure is managed as a liquid.
- Poultry manure is primarily managed by deep pit stacking or litter and is included in "other systems" in Table D7-7.

DATA SOURCES

Many states may have their own agricultural census that includes data on animal populations and production levels. Animal population data can be found from a variety of other sources, including the U.S. Census of Agriculture, USDA agriculture statistics, and from livestock manure management experts throughout the U.S. Safley et al. (1992) include animal populations and also estimate CH₄ emitted from their wastes in their report.

UNCERTAINTIES

The method described above for estimating methane emissions from animal manure is based on sound scientific data and experimental evidence. To the extent possible, emissions should be estimated with as much information as possible about the conditions under which animal manure is managed. This is particularly important when manure is managed under anaerobic conditions, such as lagoons or other liquid/slurry systems.

The estimates and assumptions used by Safley et al. (1992) are instructive for identifying the potential magnitude of emissions and the relative importance of various animals and manure management systems. However, to the extent possible, information that is specific to the individual state should be used because manure management systems and practices may vary in different states.

The weakest link in the method presented here is the estimates of the methane conversion factors (MCFs) for the individual management systems. Very few field measurements are available upon which to base these estimates, particularly for "dry" management systems such as dry lots, pastures, and paddocks. The MCFs for the "wet" management systems such as lagoons and slurry storage have a much stronger foundation. The inaccuracy in the emissions estimates due to this lack of data cannot be quantified. Emissions estimates can be improved significantly once comprehensive field measurements are performed.

This discussion has focused only on emissions of methane from animal manure. It has been mentioned, however, that animal waste decomposition also has the potential to produce nitrous oxide.

At this time no information is available on the potential for N₂O emissions: this should be investigated in the future.

Table D7-6

Regions of the U.S. for Manure Management Characterization

North East	*Connecticut, Maine, Massachusetts, *New Hampshire, New Jersey, *New York, Pennsylvania, Rhode Island, Vermont.
South East	*Delaware, *Florida, *Georgia, Maryland, *North Carolina, *South Carolina, *Virginia, *West Virginia.
Plains	*Colorado, *Kansas, *Montana, *Nebraska, *North Dakota, *South Dakota, Wyoming.
South	*Alabama, *Arkansas, Kentucky, *Louisiana, *Mississippi, *Tennessee
South West	*New Mexico, *Oklahoma, *Texas.
Mid West	*Illinois, *Indiana, Michigan, *Ohio, *Wisconsin, *Iowa, *Minnesota, *Missouri.
North West	*Idaho, *Oregon, *Washington
Far West	*Arizona, Nevada, *Utah
Pacific West	*California
North Pacific	*Alaska
Pacific Islands	*Hawaii

* States that have supplied estimates of their percent use of manure management.

Table D7-7

Livestock Manure System Usage for the U.S.

Animal	Anaerobic Lagoons	Liquid/Slurry and Pit Storage	Daily Spread	Solid Storage & Drylot	Pasture, Range & Paddock	Litter, Deep Pit Stacks and Other
Non-Dairy Cattle	0%	1%	0%	14%	84%	1%
Dairy	10%	23%	37%	23%	0%	7%
Poultry ^B	5%	4%	0%	0%	1%	90%
Sheep	0%	0%	0%	2%	88%	10%
Swine	25%	50%	0%	18%	0%	6%
Other Animals ^C	0%	0%	0%	0%	92%	8%

A Includes liquid/slurry storage and pit storage.
B Includes chickens, turkeys, and ducks.
C Includes goats, horses, mules, and donkeys.

Totals may not add due to rounding.
Source: Safley et al. (1992).

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DISCUSSION 8

METHANE EMISSIONS FROM FLOODED RICE FIELDS

OVERVIEW

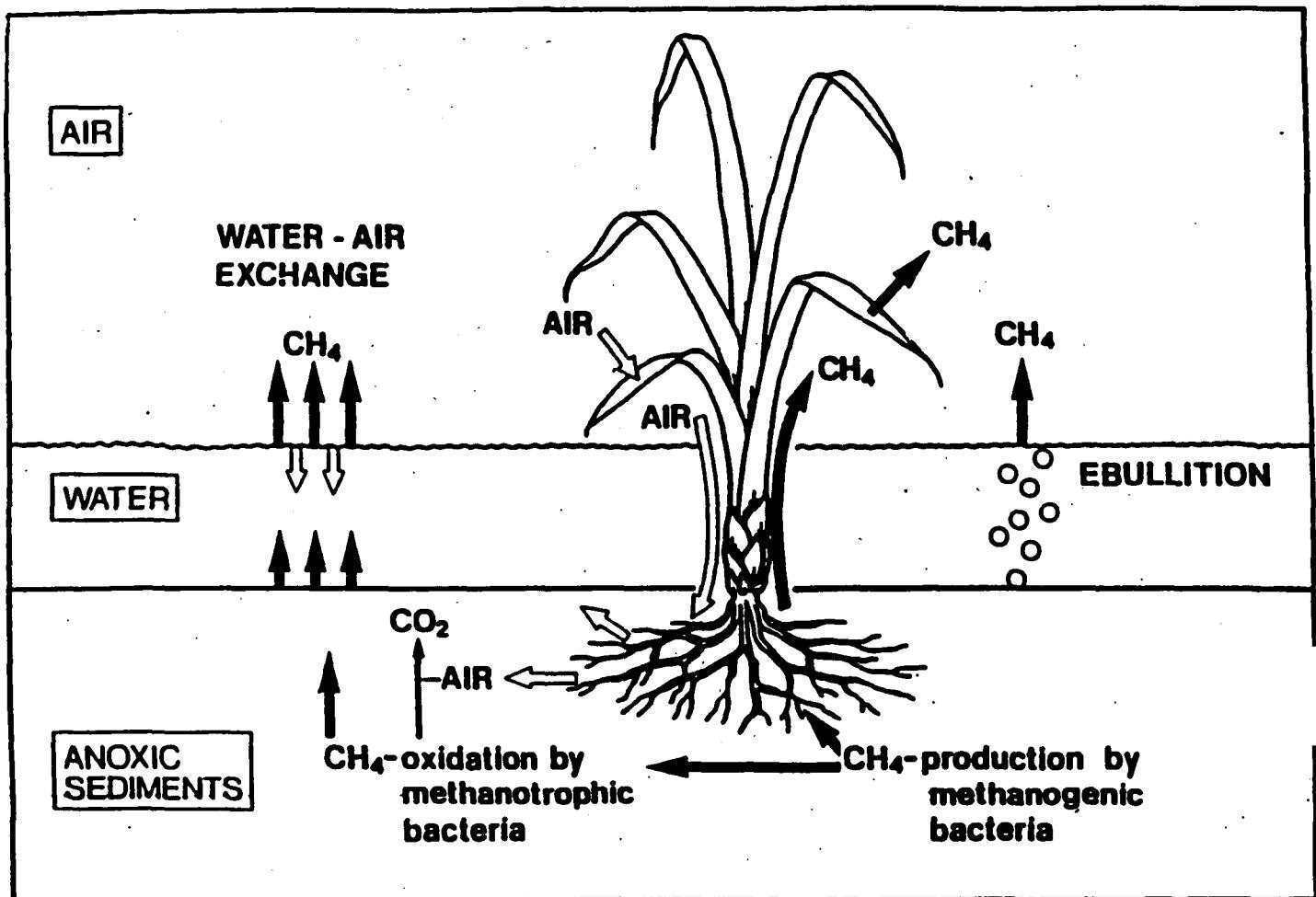
Most of the world's rice, and all of the rice in the U.S., is grown on flooded fields. When fields are flooded, aerobic decomposition of organic material gradually depletes the oxygen present in the soils and floodwater, and anaerobic conditions in the soils develop. Methane is produced through anaerobic decomposition of soil organic matter by methanogenic bacteria. However, not all of the methane that is produced is released into the atmosphere. As much as 60 to 80 percent of the produced methane is oxidized by aerobic methanotrophic bacteria in the soils (Holzapfel-Pschorn et al.; 1985; Sass et al., 1990). Some of the methane is also leached away as dissolved methane in floodwater that percolates from the field. The remaining non-oxidized methane is transported from the submerged soil to the atmosphere primarily by diffusive transport through the rice plants. Some methane also escapes from the soil via diffusion and bubbling through the floodwaters. Figure D8-1 graphically depicts the process of CH_4 production and its emissions.

The water management system under which rice is grown is one of the most important factors affecting methane emissions. Upland rice fields are not flooded, and therefore are not believed to produce methane. In deepwater rice fields (*i.e.*, fields with flooding depths greater than approximately 3.3 feet), the lower stems and roots of the rice plants are dead, thereby effectively blocking the primary CH_4 transport pathway to the atmosphere. Therefore, while deepwater rice growing areas are believed to emit methane, the quantities released are likely to be significantly less than areas with more shallow, typical flooding depths. Also, some flooded fields are drained periodically during the growing season, either intentionally or accidentally. If water is drained and soils are allowed to dry sufficiently, methane emissions decrease or stop entirely. This is due to soil aeration, which not only causes existing soil methane to oxidize but also inhibits further methane production in the soils.

Other factors that influence methane emissions from flooded rice fields include soil temperature, soil type, fertilization practices, cultivar selection, and other cultivation practices (*e.g.*, tillage, seeding, and weeding practices). Many studies have found, for example, that methane emissions increase as soil temperature increases. Several studies have indicated that some types of nitrogen fertilizer inhibit methane generation, while organic fertilizers enhance methane emissions. However, while it is generally acknowledged that these factors influence methane emissions, the extent of the influence of these factors individually or in combination has not been well quantified.

Rice cultivation is a very small source of methane in the U.S. In 1990, methane emissions from this source are estimated to have been approximately 0.65 to 4.5 MMTCE (U.S. EPA, 1994). This represents less than 1 percent of total U.S. methane emissions from all sources, and about 4 percent of U.S. methane emissions from agricultural sources. Seven states grow rice: Arkansas, California, Florida, Louisiana, Mississippi, Missouri, and Texas.

Figure D8-1. Methane Emissions from Rice Cultivation



Source: Schütz, et al. (1989)

DESCRIPTION OF WORKBOOK METHOD

Methane emissions from rice cultivation by state can be calculated using the methodology presented in Equation D8-1. This method utilizes a low and a high daily emission factor, which are multiplied by the harvested area flooded and the number of days of flooding during the growing season. Agricultural statisticians in each of the seven states in the U.S. that produce rice can be contacted to determine water management practices and flooding season lengths in each state. It should be noted that all rice growing areas in the U.S. are continually flooded; none are either upland or deepwater.¹

Equation D8-1. Method for Estimating Methane Emissions from Rice Cultivation

$$\text{Low estimate (lbs CH}_4\text{)} = (\text{average } \# \text{ of acre-days harvested annually}) \times (0.1955 \text{ lbs CH}_4/\text{acre/day})^2$$

$$\text{High estimate (lbs CH}_4\text{)} = (\text{average } \# \text{ of acre-days harvested annually}) \times (1.035 \text{ lbs CH}_4/\text{acre/day})^2$$

The default daily methane emission factors were taken from results of field studies performed in California (Cicerone et al., 1983); Texas (Sass et al., 1990, 1991a, 1991b, 1992); and Louisiana (Lindau et al., 1991; Lindau and Bollich, 1993). A range based on the endpoints of the emission rates measured in these studies -- 0.1955 lbs CH₄/acre/day to 1.035 lbs CH₄/acre/day -- can be applied to the areas and season lengths in each state.³ Since these measurements were taken in rice growing areas of the U.S., they are representative of rice soil temperatures and water and fertilizer management practices typical of the U.S.

The climatic conditions of southwest Louisiana, Texas, and Florida allow for a second or "ratoon" rice crop in those areas. This second crop rice is produced from regrowth on the stubble after the first crop has been harvested. Emission estimates for these states should include this additional harvested area.

Rice fields for the second crop typically remain flooded for a shorter period of time than for the first crop. Recent studies indicate, however, that the methane emission rate of the second crop may be significantly higher than that of the first crop. The rice straw produced during the first harvest has been shown to dramatically increase methane emissions during the ratoon cropping season

¹ Technically, wild rice is considered a grain and not a rice variety, and therefore, is not included in these calculations.

² The number of acre-days harvested annually is equal to: (the number of acres within a certain cropping length x the number of days in that cropping cycle) + (the number of acres with another cropping cycle length x the number of days in that cropping cycle) + The workbook assumes that there is only one cropping cycle for all states.

³ Two measurements from these studies were excluded when determining the emission coefficient range. A low seasonal average flux of 0.1091 lbs/acre/day in Sass et al. (1990) was excluded because this site experienced a mid-season accidental drainage of floodwater, after which methane emissions declined substantially and did not recover for about two weeks. Also, the high seasonal average flux of 3.741 lbs/acre/day in Lindau and Bollich (1993) was excluded since this emission rate is anomalously high, compared to other flux measurements in the U.S., as well as in Europe and Asia (see IPCC, 1994).

(Lindau & Bollich, 1993). It is not clear to what extent the shorter season length and higher emission rates offset each other. As scientific understanding improves, these emission estimates can be adjusted to better reflect these variables. At this juncture, however, it is recommended that the methane emission factors and flooding season lengths provided here for the primary rice crop be applied to the ratoon crop as well (see Table D8-1 for average growing season lengths).

To avoid unrepresentative results based upon fluctuations in economic or climatic conditions, a three-year average (centered on 1990) for the area harvested in each state (USDA, 1991; USDA, 1993) should be used to estimate 1990 emissions. Also, since the number of days that the rice fields remain permanently flooded varies considerably with planting system and cultivar type, a range for the growing season lengths should be obtained (see Table D8-1 for default growing season lengths by state).

Table D8-1. Growing Season Length for Rice-Producing States

State	Growing Season Length (days)	
	low	high
Arkansas	75	100
California	123	153
Florida ^a		
primary	90	120
ratoon		
Louisiana ^a		
primary	90	120
ratoon		
Mississippi	75	82
Missouri	80	100
Texas ^a		
primary	60	80
ratoon		
TOTAL		
a These states have a second, or "ratoon", cropping cycle which may have a shorter flooding season than the one listed in the table.		

UNCERTAINTIES

From field experiments it is apparent that methane emissions from rice fields are affected by many factors. The factors clearly identified by these field experiments are: (1) water level and its history in the growing season; (2) temperature; (3) fertilizer application; (4) soil type; (5) cultivar; and (6) agricultural practices such as direct seeding or transplanting. Data show that higher temperature,

continuously flooded fields, some types of organic fertilizers, and certain cultivars lead to higher emissions compared to rice grown at lower temperatures, with intermittent or managed irrigation in which fields are not continuously inundated and where chemical fertilizers are used. At present, however, there are insufficient data to incorporate most of these factors. Nonetheless, estimates can be improved substantially by incorporating the current knowledge on the first two factors, namely water levels and temperature. For some states, the effects of organic and mineral fertilizers can be included.

Application of either the commercial nitrogen fertilizers ammonium sulfate or urea has generally been found to reduce CH_4 emissions, especially if the fertilizer is deeply incorporated into the soil. This is believed to be due to suppression of CH_4 production as a result of the addition of sulfate or ammonium ions. Application of organic fertilizers (*e.g.*, rice straw, composted rice straw, animal wastes) whether or not in combination with mineral fertilizers, has been found, in most cases, to enhance CH_4 emissions. The organic fertilizers provide an additional carbon source for the production of CH_4 in the paddy soil.

Water management practice also influence CH_4 emissions since it is only through continuous flooding that paddy soil remains sufficiently reduced for methane production to occur. Cultivar selection is likely to affect CH_4 emissions through two mechanisms: (1) root exudation and (2) gas transport. Many studies have observed two or three maxima in CH_4 emissions during the growing season with the last one or two peaks occurring during the reproductive stage of the rice plants. These latter emission peak(s) may be due to peaks in CH_4 production that result from the plants providing soil organic bacteria with organic root exudates or root litter at this time (Schütz et al., 1989). The degree of root exudation that occurs is believed to vary between cultivar types. The rice plant also affects CH_4 emissions through gas transport mechanisms. Downward oxygen transport through the plant (and subsequent oxidation of CH_4 in the rhizosphere) and upward methane transport probably varies between cultivars. Gas transport mechanisms may also play a role in controlling the latter emission peaks, *e.g.*, methane transport may be more efficient during the reproductive stage of rice plants than at other developmental stages (Sass et al., 1990).

States are encouraged to go beyond the basic method provided here and add as much detail as scientifically justified based on laboratory and field experiments on how the above factors may influence emissions. For example, states may wish to develop their own emission coefficients, especially if wetland rice is a major crop.⁴ Also, where data are available on fertilizer type used, states may wish to incorporate this information into their calculations.⁵ If additional detail is included, then state emission inventories should be fully documented with the corresponding sources.

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⁴ As discussed above, because of the major variability in methane emissions over the growing season, seasonally-averaged daily emission coefficients (*i.e.*, the seasonal average of average daily emissions coefficients based on semi-continuous measurements taken over an entire growing season) should be used (see Braatz and Hogan (1991) for a description of appropriate emission measurement techniques).

⁵ See IPCC (1994) for details on how to incorporate more detail into calculations.

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DISCUSSION 9

EMISSIONS FROM AGRICULTURAL SOIL MANAGEMENT

OVERVIEW

Various agricultural soil management practices contribute to greenhouse gas emissions. The use of synthetic and organic fertilizers adds nitrogen to soils, thereby increasing natural emissions of nitrous oxide. Other agricultural soil management practices such as irrigation, tillage practices, or the fallowing of land can also affect trace gas fluxes to and from the soil since soils are both a source and a sink for carbon dioxide and carbon monoxide, a sink for methane, and a source of nitrous oxide. However, there is much uncertainty about the direction and magnitude of the effects of these other practices, so only a methodology for emissions from fertilizer use is included in the *States Workbook* at this time.

Nitrous oxide is produced naturally in soils through the microbial processes of denitrification and nitrification.¹ A number of anthropogenic activities add nitrogen to soils, thereby increasing the amount of nitrogen available for nitrification and denitrification, and ultimately the amount of N₂O emitted. These activities include application of fertilizers, atmospheric deposition, and cultivation of nitrogen-fixing crops.² Fertilizer use is the most significant source of nitrous oxide in the U.S. Nitrous oxide emissions in 1990 due to consumption of synthetic fertilizers (both multi-nutrient and nitrogen) and organic fertilizers were about 13.5 MMTCE. This represents approximately 45 percent of total U.S. nitrous oxide emissions, and about 97 percent of nitrous oxide emissions from all agricultural sources. Approximately 55 percent of the fertilizer was consumed in the Midwest (TVA, 1993).

Research has shown that a number of factors affect nitrification and denitrification rates in soils, including: water content, which regulates oxygen supply; temperature, an important factor in microbial activity; nitrogen concentration, in particular nitrate and ammonium concentration; available organic carbon for microbial activity; and soil pH. These conditions vary greatly by soil type, crop type, management regime, and fertilizer application. Moreover, the interaction of these conditions and their combined effect on the processes leading to nitrous oxide emissions are not fully understood.

DESCRIPTION OF WORKBOOK METHOD

Nitrous oxide emissions from commercial fertilizer use can be estimated using the methodology presented below:

¹ Denitrification is the process by which nitrates or nitrites are reduced by bacteria and which results in the escape of nitrogen into the air. Nitrification is the process by which bacteria and other microorganisms oxidize ammonium salts to nitrites, and further oxidize nitrites to nitrates.

² Methods to estimate emissions due to atmospheric deposition and nitrogen fixing crops are not included at this time for two reasons: these emission sources are highly uncertain, and activity data are not readily available.

$$N_2O \text{ Emissions} = FC \times EC \times 44/28$$

where: FC = Fertilizer Consumption (tons N-applied)³;

EC = Emission Coefficient = 0.0117 tons N₂O-N/ton N applied; and

44/28 is the molecular weight ratio of N₂O to N₂O as N (N₂O/N₂O-N).

The methodology includes an emission coefficient of 0.0117 tons N/ton N-applied (*i.e.*, 1.17 percent of the nitrogen applied as fertilizer is released into the atmosphere as nitrous oxide). This emission coefficient was obtained from the Agricultural Research Service of the U.S. Department of Agriculture (USDA), which estimated that 1.84 kg N₂O was emitted per 100 kg of nitrogen applied as fertilizer. After applying the appropriate conversion, this is equivalent 0.0117 tons N₂O-N/ton N-applied.

The total amount of commercial fertilizer consumed in a state is the sum of all synthetic nitrogen, multiple-nutrient, and organic fertilizer used (measured in mass units of nitrogen). Fertilizer data by type and by state can be obtained from the Tennessee Valley Authority's National Fertilizer and Environmental Research Center (TVA, 1993).⁴ There may be instances in which fertilizer consumption is given as the total mass of fertilizer consumed rather than as nitrogen content. In such cases, total mass by fertilizer type may be converted to nitrogen content using the percentages in Table D9-1.

Because agricultural activities fluctuate from year to year as a result of economic, climatic, and other variables, it is recommended that an average of three years of fertilizer consumption (centered on 1990) be used to account for extraordinary circumstances.

UNCERTAINTIES

Scientific knowledge regarding nitrous oxide production and emissions from fertilized soils is limited. Significant uncertainties exist regarding the agricultural practices, soil properties, climatic conditions, and biogenic processes that determine how much fertilizer nitrogen various crops absorb, how much remains in soils after fertilizer application, and in what ways the remaining nitrogen either evolves into nitrous oxide or into gaseous nitrogen and other nitrogen compounds.

A major difficulty in estimating the magnitude of emissions from this source has been the relative lack of emissions measurement data across a suitably wide variety of controlled conditions, making it difficult to develop statistically valid estimates of emission factors. Previous attempts have been made to develop emission factors for different fertilizer and crop types for the purposes of developing state and national emissions inventories. However, the accuracy of these emission factors has been questioned. For example, while some studies indicate that N₂O emission rates are higher

³ In some instances, state fertilizer consumption data may only be provided by fertilizer type and not aggregated across all types by total N consumed. If this is the case, then analysts must first determine the amount of N consumed for each fertilizer type (using the percentages in Table D9-1) and then follow the method presented. To obtain total emissions by state, sum across all types.

⁴ Fertilizer consumption data may be underestimates since they do not include organic fertilizers that do not enter the commercial market.

Table D9-1
Nitrogen Content of Principal Fertilizer Materials

MATERIAL	% NITROGEN
Nitrogen	
Ammonia, Anhydrous	82
Ammonia, Aqua	16-25
Ammonium nitrate	33.5
Ammonium nitrate-limestone mixtures	20.5
Ammonium sulfate	21
Ammonium sulfate-nitrate	26
Calcium cyanamide	21
Calcium nitrate	15
Nitrogen solutions	21-49
Sodium nitrate	16
Urea	46
Urea-form	38
Phosphate	
Basic slag, Open hearth	-
Bone meal	2-4.5
Phosphoric acid	-
Rock phosphate	-
Superphosphate, Normal	-
Superphosphate, Concentrated	-
Superphosphoric acid	-
Potash	
Potassium chloride (muriate)	-
Potassium magnesium sulfate	-
Potassium sulfate	-
Multiple Nutrient	
Ammoniated superphosphate	3-6
Ammonium phosphate-nitrate	27
Ammonium phosphate-sulfate	13-16
Diammonium phosphate	16-21
Monoammonium phosphate	11
Nitric phosphates	14-22
Nitrate of soda-potash	15
Potassium nitrate	13
Wood ashes	-
Blast furnace slag	-
Dolomite	-
Gypsum	-
Kieserite (emjeo)	-
Limestone	-
Lime-sulfur solution	-
Magnesium sulfate (Epsom salt)	-
Sulfur	-

Note: A dash (-) indicates no, or a negligible amount of, nitrogen present.

Source: The Fertilizer Institute, 1982.

for ammonium-based fertilizers than for nitrate, other studies show no particular trend in N₂O emissions related to fertilizer types (see Eichner (1990) and Bouwman (1990) for reviews of the literature). Therefore, it is possible that fertilizer type is not the most important factor in determining emissions. One study suggests that N₂O emissions from the nitrification of fertilizers may be more closely related to soil properties than to the type of fertilizer applied (Byrnes *et al.*, 1990).

There is consensus, however, as to the fact that numerous factors influence the biological processes of the soil microorganisms that determine nitrous oxide emissions from nitrogen fertilizer use. For discussion purposes, these factors are divided into two general categories: natural processes and management practices (see Box D9-1 for a description of each category).

While it is relatively well known how the natural processes individually affect N₂O emissions, it is not well understood how the interaction of the processes affects N₂O emissions. Experiments have shown that in some cases increases in each of the following factors (individually) enhance N₂O emissions: pH, soil temperature, soil moisture, organic carbon content, and oxygen supply (Bouwman, 1990; Eichner, 1990). However, how soil moisture, organic carbon content, and microbial population together, for example, affect N₂O emissions, is not readily predictable.

Management practices may also affect N₂O emissions, although these relationships have not been well quantified. As mentioned, levels of N₂O emissions may be dependent on the type of fertilizer used, although the extent of the effect is not clear, as demonstrated by the wide range of emission coefficients for individual fertilizer types derived in experiments (Bouwman, 1990). Although high application rates for fertilizer may cause higher

N₂O emission rates, the relationship between fertilizer application rate and nitrous oxide emission is not well understood. Deep placement of fertilizer as an application technique will result in lower N₂O emissions than broadcasting or hand placement (Stangel, 1988). Bremner *et al.* (1981) found that emissions from fertilizer applied in the fall were higher than emissions from the same fertilizer applied in the spring, indicating that the timing of fertilizer application can affect N₂O emissions. Tillage practices can also affect N₂O emissions. Tilling tends to decrease N₂O emissions; no-till and use of herbicides may increase N₂O emissions (Groffman, 1987; Breitenbeck, 1988). However, limited research at unique sites under specific conditions has not been able to account for the complex interaction of the factors, making the effects of combinations of factors difficult to predict.

Emissions may also occur from the contamination of surface and ground water due to nutrient leaching and runoff from agricultural systems. However, methods to estimate emissions of N₂O from these sources are not included in the *States Workbook* at this time due to a lack of data and emission coefficients for each contributing activity. However, because of the potential relative importance of these N₂O emissions, they should be included in the future as data availability and scientific

**Box D9-1: Factors Affecting N₂O Emissions
from Fertilizer Consumption**

Natural Processes

temperature
precipitation
soil moisture content
oxygen available porosity
pH
organic carbon content
thaw cycle
microorganisms
soil type

Management Practices

fertilizer type
application rate
application technique
crop type
timing of application
tillage practices
use of other chemicals
irrigation
residual N and C from crop/fertilizer

understanding permit.

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DISCUSSION 10

CARBON DIOXIDE EMISSIONS FROM FOREST MANAGEMENT AND LAND-USE CHANGE

OVERVIEW

The biosphere emits and absorbs a wide variety of carbon and nitrogen trace gases, including carbon dioxide (CO_2), methane (CH_4), carbon monoxide (CO), nitrous oxide (N_2O), oxides of nitrogen (NO_x), and nonmethane volatile organic compounds (NMVOCs). When humans use and alter the biosphere through forest management and land-use change activities, such as clearing an area of forest to create cropland, restocking a logged forest, draining a wetland, or allowing a pasture to revert to grassland, the natural balance of these trace gas emissions and uptake is altered and their atmospheric concentrations adjust. In the U.S., forest management is believed to be the primary land-use activity responsible for current greenhouse gas fluxes, and carbon dioxide is the most significant gas affected.

Forests are complex ecosystems with several interrelated components, each of which acts as a carbon storage pool, including:

- trees (*i.e.*, living trees, standing dead trees, roots stems, branches and foliage);
- soil;
- the forest floor (*i.e.*, woody debris and tree litter); and
- understory vegetation (*i.e.*, shrubs and bushes).

As a result of biological processes (*e.g.*, growth and mortality) and anthropogenic activities (*e.g.*, harvesting, thinning, and other removals), carbon is continuously cycled through these ecosystem components, as well as between the forest ecosystem and the atmosphere. For example, the growth of trees results in the uptake of carbon from the atmosphere and storage in living trees. As these trees age, they continue to accumulate carbon until they reach maturity, at which point they are relatively constant carbon stores. As trees die and otherwise deposit litter and debris on the forest floor, decay processes will release carbon to the atmosphere and also increase soil carbon. The net change in forest carbon is the change in the total net amount of carbon stored in each of these pools (*i.e.*, in each ecosystem component) over time.

The net change in forest carbon, however, is not likely to be equivalent to the net flux between forests and the atmosphere. Because most of the timber that is harvested and removed from U.S. forests is used in wood products, harvests may not always result in an immediate flux of carbon to the atmosphere. Harvesting in effect transfers carbon from one of the "forest pools" to a "product pool." Once in a product pool, the carbon is emitted over time as CO_2 through either combustion or decay,¹ although the exact rate of emission varies considerably between different product pools and may in fact result in effective long-term carbon storage. For example, if timber is harvested and

¹ Actually, if timber undergoes combustion, some small portion of the carbon - as much as 10 percent of the total carbon released - will be released as CO and CH_4 rather than CO_2 . In addition, if timber products are placed in landfills, about 50 percent of the carbon that eventually decomposes is oxidized to CO_2 and about 50 percent is released as CH_4 . However, eventually both CO and CH_4 oxidize to CO_2 in the atmosphere.

subsequently used as lumber in a house, it may be many decades or even centuries before the lumber is allowed to decay and carbon is released to the atmosphere. If timber is harvested for energy use, subsequent combustion results in an immediate release of carbon. Paper production may result in emissions over years or decades.

The U.S. land area is roughly 2,263 million acres, of which 33 percent, or 737 million acres, is forest land (Powell et al., 1993). The amount of forest land has remained fairly constant over recent decades declining by approximately 5 million acres between 1977 and 1987 (USFS, 1990; Waddell et al., 1989) and increasing by about 0.5 million acres between 1987 and 1992 (Powell et al., 1993). These changes represent fluctuations of well under 1 percent of the forest land area, or on average, about 0.1 percent per year. Other major land uses in the U.S. include range and pasture lands (36 percent), cropland (18 percent), urban uses (3 percent); and other lands (10 percent) (Daugherty, 1991).² Urban lands are the fastest growing land use.

Given that U.S. forest land area changed by only about 0.1 percent per year between 1987 and 1992, the major influences on the net carbon flux from forest land are management activities and ongoing impacts of previous land-use changes. These activities affect the net flux of carbon by altering the amount of carbon stored in the biomass³ and soils of forest ecosystems. For example, intensified management of forests can increase both the rate of growth and the eventual biomass density of the forest, thereby increasing the uptake of carbon. The reversion of cropland to forest land through natural regeneration will, over decades, result in increased carbon storage in biomass and soils (*i.e.*, in general, forests contain more biomass and soil carbon than cropland).

The net CO₂ flux in 1990 due to forest management activities and the regeneration of previously cleared forest area is estimated to have been an uptake (sequestration) of 119 MMTCE (U.S. EPA, 1994). This carbon uptake represents an offset of about 9 percent of the CO₂ emissions from energy-related activities. The Northeast, North Central, and South Central regions of the U.S. account for 98 percent of the uptake of carbon, largely due to high growth rates that are the result of intensified forest management practices and the regeneration of forest land previously cleared for cropland and pasture. Western states are responsible for a small net release of carbon, reflecting mature forests with a near balance between growth, mortality, and harvest.

DESCRIPTION OF WORKBOOK METHOD

The method provided in Workbook Section 10 focuses on land-use changes and forest management activities that result in the largest potential flux of CO₂ to the atmosphere or have the largest potential for sequestering carbon. These include activities that:

- affect the amount of biomass in existing biomass stocks on forests and other land, without changing the way land is used (*e.g.*, management of standing forests, urban tree planting, logging), or

² Other lands include farmsteads, transportation uses, marshes, swamps, deserts, tundra, and miscellaneous other lands.

³ Biomass is a shorthand term for organic material. The amount of biomass in a given land area includes all the living and dead organic material, both above and below the ground surface.

- change the way land is used (*e.g.*, clearing forests for agricultural use or suburban development, converting a grassland to cropland).

The dominant gas of concern in this source category is CO₂, and the methodology presented below is specific to CO₂. Other important greenhouse gases, including CH₄ and N₂O, and photochemically important gases, including CO, NO_x, and NMVOCs are also produced from forest management and land-use change activities. However, emissions of these gases that result from biomass burning (*i.e.*, wood consumption for energy production) are captured in Discussion Section 14, while emissions of these gases due to other activities (such as land flooding) are not yet explicitly included in the methodology. Instead, they are discussed as areas for further research in the uncertainties section of this chapter.

The fundamental basis for the methodology rests upon two linked themes: (1) the flux of CO₂ to or from the atmosphere is assumed to be equal to changes in the carbon stocks of existing biomass and soils, and (2) changes in the carbon stocks can be estimated by first establishing rates of change in land use and then applying simple assumptions about the biological response to the land use. The methodology is designed to be comprehensive, *i.e.*, cover all the main land-use change and forestry activities in the U.S., and to be feasible to implement by all states.

In estimating the effects of forest management activities, land use and land-use change on fluxes of greenhouse gases, it is reasonable to stage the calculation methods so that the most important components can be addressed first. Complexities and subtleties of the relationship of forestry and land-use change to fluxes of CO₂ and other gases can be incorporated in a consistent manner into subsequent calculations as knowledge advances and data improve. The methodology presented here focuses on a simple, practical, and fair procedure for determining the CO₂ flux directly attributable to forest management and land-use change activities. This procedure also accounts for the influence of past land-use changes on the contemporary CO₂ flux. It should be noted, however, that this method is based upon many simplifying assumptions in order to allow for implementation with only minimal data (these simplifying assumptions are discussed in detail later in this section). At the same time, the methodology is sufficiently flexible to accommodate users with different levels of available data, *i.e.*, data with different levels of complexity and at different geographic scales. States are encouraged to apply the method in as detailed a manner as their data allow, as well as to estimate emissions from land-use activities that are not explicitly included in the method if expertise and data are sufficient.

This section is divided into three parts, each of which reflects a general category of land-use change and forest management activities. They are (see Figure D10-1 for a breakdown of the activities associated with each of the categories described below):

- **Changes in Forests and Other Woody Biomass Stocks:** The most important effects of human interactions with existing forests are considered in this single broad category, which includes commercial management and logging for forest products, replanting after logging or other forest timber removal, the harvest of fuelwood, and the establishment and operation of forest plantations as well as planting trees in urban, suburban, or other non-forest locations.
- **Forest and Grassland Conversion:** This category includes the conversion of forest and grasslands to pasture, croplands, or other managed uses as well as to shopping malls, parking lots, and suburban communities. These activities can significantly change the carbon stored in biomass and in soils.

- **Abandonment of Managed Lands:** Lands that had been managed previously (*i.e.*, croplands, pasture) and that are abandoned and allowed to regrow naturally, without any human interference, can reaccumulate significant amounts of carbon in their biomass and soils. This category includes these lands that are regrowing naturally into their prior grassland or forest conditions.

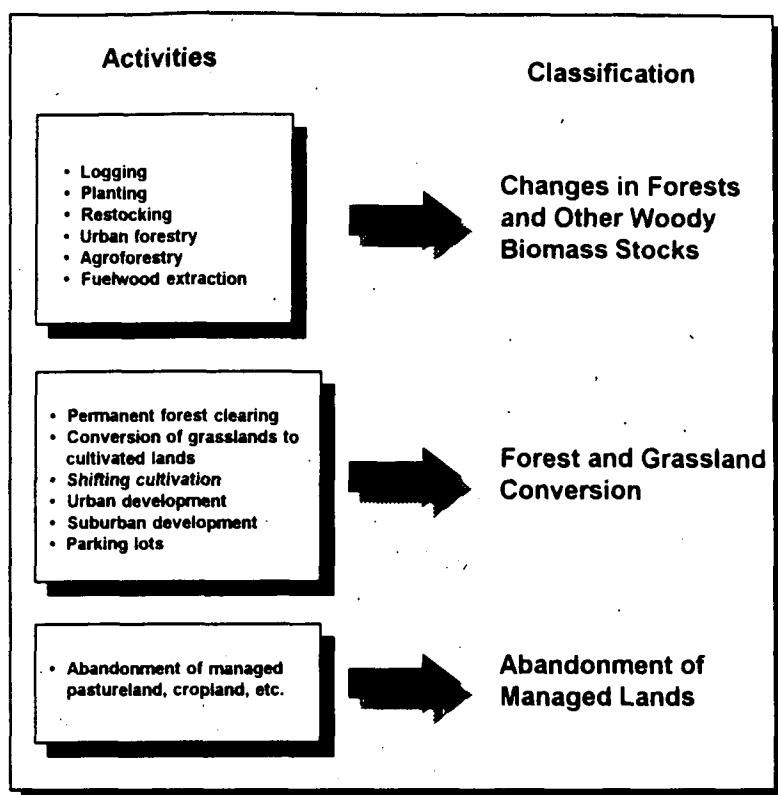
1. CO₂ FLUX FROM CHANGES IN FORESTS AND OTHER WOODY BIOMASS STOCKS

This category as used in these basic calculations is very broad, potentially including a wide variety of land-uses and management practices. This discussion focuses heavily on changes in forests, which account for the largest component of annual changes in biomass stocks in the U.S. However, other types of biomass, such as non-forest trees (*e.g.*, in towns and cities) and woody shrubs on grasslands should be included if a state believes these are a significant component of total changes of biomass stocks.

A basic organizing concept in the section is that all existing forests can be allocated into one of three categories:

- (1) Natural, undisturbed forests, where they still exist and are in equilibrium, should not be considered either an anthropogenic source or sink. They should, therefore, be excluded from state inventory calculations.
- (2) Forests regrowing naturally on abandoned lands are a net carbon sink attributable to past human activities and are accounted for as discussed in the section on emissions from abandoned lands. While current regrowth is considered a response to past anthropogenic activity, "abandoned lands" are by definition assumed not to be subject to ongoing human intervention after abandonment.
- (3) All other types of forests are included in the changes in forests and other woody biomass stocks category. That is, any forest which experiences periodic or ongoing human intervention that affects carbon stocks should be included here. In the basic calculations, the focus is on primarily a few types of human interactions with forests which are believed to result in the most significant fluxes of carbon. State experts are encouraged, however, to estimate emissions for any activity related to existing forests which is considered to result in significant

Figure D10-1. Land-Use Change and Forestry Activities Covered in Method



carbon emissions or removals and for which necessary data are available.

Some of the activities in the changes in forests or other woody biomass stocks category which can potentially produce significant carbon fluxes are:

- management of commercial forests -- including logging, selective thinning, restocking, etc., as practiced by commercial forest products industries;
- establishment and management of commercial plantations⁴;
- other afforestation or reforestation programs; and
- informal non-commercial fuelwood, timber, and other wood harvest.

This category also includes trees which may not traditionally be considered part of forests, such as urban trees, trees planted along highways, aircraft runways, etc. These dispersed trees do not contribute greatly to carbon fluxes to or from the atmosphere, however, they may be of interest to some states because of their potential use in response strategies.

As illustrated in the above list, the changes in forests and other woody biomass stocks category includes some tree planting activities which, strictly speaking, are land-use changes. Plantation establishment and other afforestation/reforestation programs are examples. It is recognized that this is conceptually inconsistent as the category is intended to account for ongoing interactions with existing forests. However, from a pragmatic perspective, including these activities within the category can simplify the calculations. These subcategories are land-use changes which create new forest stocks. As soon as the land-use change occurs (*i.e.*, tree planting), the new land becomes part of the changes in forests and other woody biomass stocks category which is accounted for on an annual incremental basis. The following three equations summarize the recommended method (which is presented step-by-step in Workbook Section 10):

Equation 1. Annual Biomass Carbon Uptake

$$U = \sum_f [(AP_f \times GP_f \times CP_f) + (T_f \times GT_f \times CT_f)]$$

where:

AP	=	area of plantations and managed forests (10^3 acres)
GP	=	annual biomass growth rate (t dm/acre/yr)
CP	=	C fraction for plantations and managed forests (t C/t dm)
T	=	number of trees planted (10^3 s)
GT	=	annual biomass growth rate (t dm/tree/yr)
CT	=	C fraction for trees planted (t C/t dm)
f	=	forest type

⁴ Plantations are forest stands that have been established artificially to produce a forest product crop.

Equation 2. Annual Biomass Carbon Release

$$R = \sum_f [(CH_f \times EF_f) + FW_f + OW_f - FC_f] \times C_f$$

where:

CH	=	commercial harvest (10^3 ft 3 /yr)
EF	=	biomass conversion/expansion factor (t dm/ft 3) ⁵
FW	=	annual fuelwood consumption (10^3 t dm/yr)
OW	=	other wood use (10^3 t dm/yr)
FC	=	wood removed during forest conversion and used as fuelwood (10^3 t dm/yr) ⁶
C	=	C fraction (t C/t dm)
f	=	forest type.

Equation 3. Net CO₂ Flux from Changes in Forests and Other Woody Biomass Stocks

$$\text{Net CO}_2 (\text{tons/yr}) = (R - U) \times 44/12$$

where:

R	=	annual biomass C release (t C/yr)
U	=	annual biomass C uptake (t C/yr)

Estimates of average annual accumulation of dry matter as biomass per acre are presented for forests naturally regrowing by broad category in Tables D10-1 and D10-2. These values can be used for default values for growth rates in similarly managed forest categories if no other information is available. For forests that are more intensely managed, annual growth increments can be quite different. Values for some typical plantation species are presented in Table D10-3 and can be used as default values. For non-forest trees, such as urban tree planting, accounting would be done on the basis of number of trees (e.g., in thousands) rather than for acres of land. The calculations would be the same, except the average annual growth would be expressed in tons of dry matter per tree rather than per acre. The recommended unit of calculation is tons of dry matter (or dry biomass), and needs to be converted to carbon for emissions estimation. A general default value of 0.5 tons C/ton dry matter is recommended for all biomass calculations. If more accurate conversion values are available

⁵ To include the decay of forest products left after harvest, the harvested amounts are adjusted in two ways: (1) the volume of biomass must first be converted to mass of dry matter; and (2) an expansion ratio is applied to account for non-commercial biomass (limbs, small trees, etc.) harvested with the commercial biomass and left to decay.

⁶ For estimating annual biomass emissions, all of the harvested biomass from forests is summed and the portion of harvested material used as fuelwood is subtracted, because emissions from fuelwood are accounted for in the following section on forests and grasslands conversion. This subtraction is done to avoid double-counting emissions.

for the particular species, these should of course be used.⁷

The methodology is designed to accommodate users at several levels of detail. This is especially important in the managed forests category. Many states have highly developed forest industries that keep detailed records of existing commercial forests and forests managed by non-industrial private forest owners. In addition, the U.S. Forest Service (USFS) compiles detailed forest inventory statistics every five years. For such states, it is possible to derive from survey results aggregate values comparable to the data and assumptions used in the approach provided in Workbook Section 10, and present them in this common format.⁸

Table D10-1
Aboveground Dry Matter in Tropical Forests
(t dm/acre)

Moist Forest		Seasonal Forest		Dry Forest	
Primary	Secondary	Primary	Secondary	Primary	Secondary
515.6	425.9	313.8	269	134.5	56

Source: Derived from IPCC, 1994

Table D10-2
Aboveground Dry Matter in Temperate and Boreal Forests
(t dm/acre)

	Temperate Forests		Boreal Forests
	Evergreen	Deciduous	
Primary	661.3	560.4	369.8
Secondary	493.2	392.3	269

Source: Derived from IPCC, 1994

Changes in forests or other woody biomass may be either a source or a sink of CO₂ in a given year in a state. The simplest way to determine which, is by comparing the annual biomass growth versus annual harvest, including the decay of forest products produced from harvested biomass. Harvested wood releases carbon at rates dependent upon its method of processing and its end-use; waste wood is usually burned immediately or within a couple of years, paper usually decays in up to 5 years (although landfilling paper can result in longer-term storage of carbon and eventual release of CH₄ or CO), and lumber and durable wood products decay in up to 100 years or more. Forest

⁷ For region-specific data in the U.S., see Birdsey and Heath (1993) and Birdsey (1992).

⁸ For region-specific data in the U.S., see USFS (1990) and Waddell (1989).

Table D10-3
Average Annual Accumulation of Dry Matter as Biomass in Plantations

Forest Types		Average Annual Increment in Biomass (t dm/acre/yr)
Tropical	<i>Acacia</i> spp.	33.6
	<i>Eucalyptus</i> spp.	32.5
	<i>Tectona grandis</i>	17.9
	<i>Pinus</i> spp.	25.8
	<i>Pinus caribaea</i>	22.4
	Mixed Hardwoods	15.2
	Mixed Fast-Growing Hardwoods	20
	Mixed Softwoods	32.5
Temperate	Douglas Fir	13.5
	Loblolly Pine	9

Source: Derived from IPCC, 1994

harvest could result in a net uptake of carbon if the wood that is harvested is used for long-term products such as building lumber and furniture, and regrowth is relatively rapid. This may in fact become part of a response strategy for some states.

For the purposes of the basic calculation, however, the recommended default assumption is that all carbon removed in wood and other biomass from forests is oxidized in the year of removal. This is because new products from current harvests frequently replace existing product stocks, which are in turn discarded and oxidized. This clearly would not be accurate if relative sizes of forest product pools change significantly over time, but is considered a legitimate, conservative assumption for initial calculations. Storage of carbon in wood products can be included in a state inventory, however, if a state can document that existing stocks of long-term forest products are in fact increasing (or decreasing). If data permit, a state could add a component to Equation (2) to account for increases (or decreases) in forest product pools (see Table D10-4 for default values for recycle rates and average product lives for various forest products).

To summarize, the net growth of biomass stocks (and accumulation of carbon) depends on the type of biomass stock and the intensity and type of management. Well managed commercial forests would, over the long-term, be expected to have net emissions close to zero. In many cases, where historically cleared areas are regrowing under commercial management, the forest areas act as a sink. If forests are logged or harvested at a rate which exceeds regrowth, then there is a net loss of carbon.

Table D10-4. Average Lifetimes for Selected Forest Products

Final End-Use	Single-Use Life	Recycle Rate	Adjusted Life in Use
1-Family House	60	0.030	61.9
Multi-Family House	50	0.030	51.5
Mobile Home	12	0.107	13.4
Residential Maintenance and Repair	30	0.107	33.6
Non-residential Construction	67	0.030	69.1
Manufacturers	12	0.107	13.4
Shipping	6	0.107	6.7
Other Solid Wood Uses	30	0.107	33.6
Newsprint	1	0.230	1.3
Printing and Writing Paper	6	0.070	6.5
Tissue Paper	1	0.000	1
Packaging Paper	1	0.150	1.2

Source: Row and Phelps, 1991

Note: Carbon held in wood that is transformed into forest products will not be admitted to the atmosphere until the product burns or decays. To calculate the amount and timing of these emissions requires that the amount of wood allocated to each end-use and the average life-time of the forest product be determined. The table above provides the estimated average life for a single-use cycle, the recycle rate, and the adjusted average use life for 12 final end-use categories. The adjustment for recycling adds several years to the effective half-life of building materials. This adjustment has an even greater effect on the average life for most types of paper products. However, the life of paper products is considerably shorter than that of durable wood products.

2. FOREST AND GRASSLAND CONVERSION

This category includes conversion of existing forests and natural grasslands to other land uses, including agriculture, highways, urban development, etc. As with all categories of forest management and land-use change activity, it is necessary to determine net CO₂ flux from biomass loss. The basic calculations employ the same simplifying assumption regarding biomass removals in this part as in the previous part, *i.e.*, that biomass removals replace existing stocks that are in turn oxidized. Therefore, in the calculations, biomass removals are treated like instantaneous emissions. This methodological simplification in effect accounts for current emissions due to decay of materials cleared in previous years, assuming that rates of land conversion and allocations to product pools have not changed significantly over time.

Forest and grassland conversion also results in CO₂ emissions through soil disturbance and oxidation of soil organic matter, particularly when the conversion is to cultivated lands or urban development. This is a long-term process which may continue for many years after the land-use change occurs. The basic calculations allow for estimation of current emissions from soil carbon disturbance due to current and previous land conversion through an averaging approach.

In some countries, when forests are cleared, significant amounts of the cleared biomass are burned to prepare the lands for cultivation or pasture. In addition to CO₂, this biomass burning releases CO, CH₄, N₂O and NO_x. However, this part of the method does not account for any non-CO₂ emissions from biomass burning. There are two basic reasons for omitting these emissions from

the method presented here:

- Land clearing by burning is rarely practiced in the U.S. due to regulatory and practical considerations, therefore, emissions from this source are assumed to be zero.
- Any non-CO₂ emissions that result from this source are assumed to be due to the use of cleared biomass as fuelwood in fireplaces, woodstoves, etc. These emissions are captured in the calculations for wood combustion presented in Discussion Section 14.

Emissions of CO₂ due to forest clearing and grassland conversion are calculated through a sequence of steps that estimate:

- the net change in aboveground biomass carbon;
- current emissions from loss (decay and burning) of net biomass cleared; and
- current releases of carbon from soils due to conversions over the previous 25 years.

The method presented in Workbook Section 10 is summarized in equations 4 through 6 below.

Equation 4. Carbon Released from Loss of Biomass

$$C \text{ Released as Loss of Aboveground Biomass } (1,000 \text{ t C/yr}) = \sum_f [AA_f \times (BC_f - AC_f)] \times CF_f$$

where:

AA	=	annual area converted (10^3 acres/yr)
BC	=	aboveground biomass before conversion (t dm/acre)
AC	=	aboveground biomass after conversion (t dm/acre)
CF	=	carbon fraction of aboveground biomass (t C/t dm)
f	=	forest/grassland type

5. Carbon Released from Soil

$$\text{Soil Carbon Released } (1,000 \text{ t C/yr}) = \sum_f [(AA-25_f \times CC_f) \times CF-25_f]$$

where:

AA-25	=	average annual area converted over 25-year period (10^3 acres/yr)
CC	=	carbon content of soil before conversion (t/acre)
FC-25	=	fraction of carbon released over 25-year period (t C/yr)
f	=	forest/grassland type

Equation 6. Total CO₂ Released

$$\text{Total Annual CO}_2 \text{ Released (1,000 t CO}_2/\text{yr}) = \sum_f (BL_f + SL_f) \times 44/12$$

where:

- BL = emissions from biomass loss (10^3 t C/yr)
SL = emissions from soil (10^3 t C/yr)
f = forest/grassland type

First, the amount of aboveground biomass affected by conversion in the emissions inventory year is calculated by multiplying the annual forest area converted to other land uses by the net change in aboveground biomass. This calculation is carried out for each relevant forest/grassland type. The net change is the difference between the density (tons dry matter per acre) of aboveground biomass on that forest/grassland prior to conversion, and the density of aboveground biomass after clearing. The after clearing value includes the biomass that regrows on land in the year after conversion and any original biomass that was not completely cleared.

It is suggested that the annual CO₂ flux associated with the loss of soil carbon following forest clearing or grassland conversion is calculated using a 25-year time horizon to account for delayed releases of soil carbon. The historical release of carbon from soil is simply the average annual land clearing times the change in carbon stock in soil between the original land use and a, e.g., 25-year old pasture or urban development. For simplicity, it is assumed that the soil carbon release is linear over the 25-year period.

The annual rate of soil carbon loss would be the total change in soil carbon from before conversion to after conversion, divided by 25. The currently available information on soil carbon changes after conversion relates primarily to temperate and boreal forests and temperate grasslands. Research indicates that approximately 50 percent of the soil carbon in the active layer (roughly the top 3 feet) is lost over a 50-year period, with most of this loss occurring in the first 25 years. However, these values are highly uncertain. The actual rate of soil carbon loss in a particular area of agricultural land, for example, is a function of the specific agricultural use of, and management practices on, the land. However, the general values above can be used as a default for initial calculations, if more accurate information or measurements are not available. This would imply that the annual rate of soil carbon loss would be 2 percent (50 percent/25 yrs).

The contemporary flux associated with past land-use change could be calculated by multiplying the number of acres of land converted in each of the previous 25 years by an annual per acre loss in soil carbon and summing over all years. Alternatively, the average annual historical conversion rate over a 25-year period could be multiplied by the annual loss rate times 25. The average rate of conversion is simply the total acres converted over the period divided by 25 years. The division by 25 and multiplication by 25 cancel each other and can be ignored. The recommendation is to use average values for the rate of land conversion, soil carbon content, and portion of the soil carbon lost over time. This averaging approach is used in the method to simplify the calculations and to reduce data requirements. Table D10-5 provides average values for soil carbon in forest systems.⁹

⁹ For region-specific data in the U.S. see Birdsey (1992).

Table D10-5
Carbon in Forest Soils
(tons C/acre)

Forest Type			
Tropical	Moist	Seasonal	Dry
	257.8	224.2	134.5
Temperate	Evergreen	Deciduous	
Primary	300.4	300.4	
Secondary	269.0	269.0	
Boreal			
Primary	461.8		
Secondary	414.7		

Source: Derived from IPCC, 1994

3. ABANDONMENT OF MANAGED LANDS

If managed lands, *e.g.*, croplands and pastures, are abandoned, carbon may re-accumulate on the land and in the soil. The response of these converted systems to abandonment depends on a complexity of issues including soil type, length of time in pasture or cultivation, previous management practices, and the type of original ecosystem of the land. Some abandoned lands may be too infertile, saline, or eroded for regrowth to occur. In this case, either the land remains in its current state or it may further degrade and lose additional organic material (*i.e.*, carbon in the biomass and the soils). Therefore, to calculate changes in carbon flux from this activity, the area abandoned should first be split into parts: lands that re-accumulate carbon naturally, and those that do not or perhaps even continue to degrade.

Abandoned lands must be evaluated in the context of the various natural ecosystems originally occupying them (*e.g.*, moist forest, dry forest, grassland). In addition, the effect of previous patterns of management prior to abandonment should be considered while recognizing the desire for simplicity and practicality of the method. The process of recovery of aboveground biomass is generally slower than the human-induced oxidation of biomass. With this in mind, it is recommended that abandoned lands be evaluated in two time horizons: a 20-year horizon to capture the more rapid growth expected after abandonment; and from 20 years after abandonment up to 100 years. The method recommended in Workbook Section 10 is divided into five steps and is summarized in the following equations (**note:** completing equations 9 and 10 is optional and should only be considered if data are readily available):

Equation 7. Carbon Uptake from Aboveground Biomass (≤ 20 yrs.)

$$\text{Annual Carbon Uptake for Aboveground Biomass (t C/yr)} = \sum_e (AY_e \times RB_e \times C_e)$$

where:

- AY = total area abandoned and regrown during last 20 years (10^3 acres)
RB = annual rate of aboveground biomass accumulation (t dm/acre/yr)
C = C fraction of biomass (t C/t dm)
e = regrowth ecosystem type

Equation 8. Carbon Uptake from Soils (≤ 20 yrs.)

$$\text{Annual Carbon Uptake for Soils (t C/yr)} = \sum_e (AY_e \times RS_e)$$

where:

- AY = total area abandoned and regrown during last 20 years (10^3 acres)
RS = annual rate of C uptake in soils (t C/acre/yr)
e = regrowth ecosystem type

Equation 9. Carbon Uptake from Aboveground Biomass (20 - 100 yrs.)

$$\text{Annual Carbon Uptake for Aboveground Biomass (t C/yr)} = \sum_e (AO_e \times RB_e \times C_e)$$

where:

- AO = total area abandoned and regrown, between 20 and 100 years that is regenerating (10^3 acres)
RB = annual rate of aboveground biomass accumulation (t dm/acre/yr)
C = C fraction of biomass (t C/t dm)
e = regrowth ecosystem type

Equation 10. Carbon Uptake from Soils (20 - 100 yrs.)

$$\text{Annual Carbon Uptake for Soils (t C/yr)} = \sum_e (AO_e \times RS_e)$$

where:

- AO = total area abandoned and regrown, between 20 and 100 years that is
 regenerating (10^3 acres)
 RS = annual rate of C uptake in soils (t C/acre/yr)
 e = regrowth ecosystem type

Equation 11. Total CO₂ Uptake

$$\text{Total CO}_2 \text{ Uptake on Abandoned Lands (t CO}_2\text{/yr)} = (A + B + C + D) \times 44/12$$

where:

- A = annual C uptake in aboveground biomass, \leq 20 years (t C/yr) (Step 1)
 B = annual C uptake in soils, \leq 20 years (t C/yr) (Step 2)
 C = annual C uptake in aboveground biomass, between 20 and 100 years
 (t C/yr) (Step 3)
 D = annual C uptake in soils, between 20 and 100 years (t C/yr) (Step 4)

In the basic calculation (as presented above), only those lands that begin to return to their previous natural state are considered. Those that remain constant with respect to carbon flux can be ignored. Likewise, the CO₂ flux to the atmosphere for those lands that continue to degrade is likely to be small, and hence is ignored in these basic calculations.

Table D10-6 presents estimates of average annual aboveground biomass accumulation in vegetation in various regrowing forest ecosystems following abandonment of cultivated land or pasture. These general growth rates should be considered crude approximations as applied to the particular lands regrowing in a given state. Accumulation of aboveground biomass can be converted to carbon using a general default conversion value for biomass of 0.5 tons carbon per ton dry matter.

If lands are regenerating to grasslands, then the default assumption is that no significant changes in aboveground biomass occur (this can be varied based on locally available data). Default rates for soil carbon uptake for both forests and grasslands can be derived from the expected soil carbon values for fully restored natural systems and some simple assumptions. In temperate and boreal systems, it can be assumed that soil carbon accumulates linearly for some base value (e.g., 50-70 percent of original stocks). Table D10-7 provides default soil carbon values for these systems. (Soil carbon changes in tropical systems are poorly understood and can be included or ignored in the basic calculations at the discretion of state experts. Experts can consult Birdsey (1992) for region-specific estimates of soil carbon).

Table D10-6
Average Annual Biomass Uptake by Natural Regeneration
(t dm/acre)

Region	Forest Types					
	Moist Forests		Seasonal Forests		Dry Forests	
	0-20 yrs	20-100 yrs	0-20 yrs	20-100 yrs	0-20 yrs	20-100 yrs
Tropical	17.9	2.0	11.2	1.1	9.0	0.56
<p>Note: Growth rates are derived by assuming that tropical forests regrow to 70 percent of undisturbed forest biomass in the first twenty years. All forests are assumed to regrow to 100 percent of undisturbed forest biomass in 100 years. Assumptions on the rates of growth in different time periods are derived from Brown and Lugo, 1990.</p>						
Temperate	0-20 yrs		20-100 yrs			
	Evergreen	6.7		6.7		
	Deciduous	4.5		4.5		
Boreal	2.24		2.24			
<p>Source: Derived from IPCC, 1994</p> <p>Note: Temperate and boreal forests actually require considerably longer than 100 years to reach the biomass density of a fully mature system. Harmon et al. (1990), for example, report carefully designed simulations indicating that a 100-year old stand of douglas fir would contain only a little over half the biomass of a 450-year old growth stand of the same species. There is also evidence that growth rates in temperate and boreal systems are more nearly linear over different age periods than is the case for tropical systems. Nabuurs and Mohren (1993) suggest that growth rates for several different species in temperate and boreal zones rise slowly and peak at ages of 30 - 55 years and decline slowly thereafter. This suggests that using the same default values for 0-20 years and 20-100 years may be a reasonable first approximation. Nabuurs and Mohren (1990) also illustrate that growth rates may vary as much as a factor of ten for stands of the same species and age, depending on site-specific conditions.</p>						

Table D10-7
Annual Soil Carbon Accumulation in Temperate and Boreal Forests
(tons C/acre/yr)

Temperate		Boreal
Evergreen	Deciduous	
2.9	2.9	4.5

Source: Derived from IPCC (1994).

The base value at the start of the re-accumulation process in soils would depend on the average amount of time that cleared lands had been used for agricultural purposes before abandonment and on management practices utilized during the agricultural period. Based on simple default assumptions for soil carbon losses from forest clearing, experts can calculate the level to which soil carbon would have fallen during the agricultural use period. The default assumption is that after 20 years, soil carbon would have fallen to 50 percent of the pre-clearing value (*i.e.*, 2 percent per year linear average change).

Available evidence indicates that, on average, soil carbon re-accumulates in soils after abandonment, at a slower rate than it is lost under cultivation. In the forest clearing calculations the default assumption is that soil carbon is lost at an average rate of 2 percent of the original carbon content per year. If no detailed information is available, a default assumption could be that the soil accumulation occurs linearly at roughly one-half this rate after abandonment. The values derived, therefore, are 1.43 tons carbon per year for temperate evergreen and deciduous forest soils and 2.2 tons carbon per year for boreal forests.

4. CO₂ EMISSIONS/UPTAKE FROM ALL FOREST MANAGEMENT AND LAND-USE ACTIVITIES

To calculate total CO₂ emissions/uptake from all forest management and land-use activities within a state, an analyst must sum the figures estimated in the previous three sections. Specifically:

Equation 12. Net CO₂ Emissions/Uptake from Forests and Land-Use Change

$$\text{Total CO}_2 \text{ Emissions/Uptake (1,000 t C/yr)} = \text{Step 1} + \text{Step 2} + \text{Step 3}$$

where:

- | | |
|---------|---|
| Step 1: | Net CO ₂ emissions/uptake from changes in forests and woody biomass stocks (10 ³ t CO ₂ /yr) |
| Step 2: | Net CO ₂ emissions from forest and grassland conversion (10 ³ t CO ₂ /yr) |
| Step 3: | Net CO ₂ emissions/uptake from abandoned lands (10 ³ t CO ₂ /yr) |

ALTERNATE METHODOLOGY

A less complex method for estimating net emissions from a state's forest management activities would be to obtain information from the USFS on forest inventories for two separate years and determine the change in biomass and soil carbon stocks over time. For example, using timber volume statistics from 1987 and 1992 U.S. forest inventories (the most recent inventories compiled by the USFS), a state could derive estimates of the total carbon stored in forest biomass and soils for each of the two years. The difference between total carbon storage in each year would represent the net change in carbon stocks over the five year period (including harvests and regrowth). This result could then be divided by 5 to determine the average annual change in carbon stocks. This is the approach used by Birdsey (1992) to estimate carbon storage and accumulation in U.S. forests.

If analysts choose this method, they should understand that:

- (1) The USFS inventories of timber volume include only timberlands, i.e., forest lands that are producing or are capable of producing crops of industrial wood and are not withdrawn from timber utilization by statute or administrative regulation (Waddell et al., 1989). Although timberlands are likely to account for the bulk of changes in carbon stocks on forest lands, there are likely to be other lands on which carbon stocks are changing. Such lands might include, for example, marginal croplands that have been planted with trees but that are in the early stages of regrowth so that they have not yet been reclassified as forest land. In addition, the timberland statistics do

- not include disperse tree planting in urban and suburban areas, along highways, etc.
- (2) This method ignores carbon uptake on the regrowth of abandoned lands unless they have been reclassified as forest lands.
 - (3) This method assumes that all of the carbon removed is oxidized during the period of removal.
 - (4) All sources must be documented.

UNCERTAINTIES AND REFINEMENTS

There are a number of areas where the basic method could be improved. Simplifying assumptions have been made in many places in order to produce methods that accommodate users with different levels of available data. The basic calculations focus only on the most important categories for emissions of CO₂ within a much larger set of forest management and land-use activities that impact greenhouse gas fluxes. Some activities are known to affect greenhouse gas fluxes, but cannot be quantified because of scientific uncertainty. Many of these issues are summarized below to assist state analysts in considering which, if any, of these possible refinements could be included in state inventories, either currently, or as future scientific understanding improves. Possible refinements or additions to basic categories could include:

Changes in Forests and Woody Biomass Stocks Section:

- *Prescribed Burning of Forests: Non-CO₂ Trace Gases.* Prescribed burning is a method of forest management by which forests are intentionally set on fire in order to reduce the accumulation of combustible plant debris and thereby prevent forest fires (which could possibly be even more destructive). Because carbon is allowed to re-accumulate on the land after burning, no net CO₂ emissions occur over time, although emissions of CH₄, CO, N₂O, and NO_x result from the biomass combustion. The matter of prescribed burning is complex because of two issues. First, there is the question of the rate of change that humans have induced and, second, there is the question of releases of trace gases several years after the burning. Also, some scientists have suggested that prescribed forest burning may actually increase carbon stocks in forests and hence serve as a sink for CO₂. Unless these uncertainties can be resolved by state experts, it is suggested that activities associated with prescribed burning not be included in the method.
- *Soil Carbon.* In the basic calculations, no soil carbon accumulation is assumed while plantations are being established (or other tree planting activities are occurring) on previously non-forested lands. If plantations are established where natural or managed forests previously existed, then the carbon content of soils may not change significantly. However, it is possible that the establishment of plantations on previously non-forested lands could result in accumulation of soil carbon over time. Further investigation may be useful to determine whether this is a significant enough effect to warrant addition to the calculations. In addition, it is likely that different forest management practices can affect soil carbon over long periods of time, as in the case of agricultural activities.

Import and Export of Wood and Wood Products. A significant portion of wood and wood products, including lumber, paper and paper products, furniture, etc., are shipped across state lines and internationally. This interstate and international transfer of wood and wood products can potentially have a notable affect on current existing stocks of woody biomass in a state. This issue should be addressed in a manner similar to the import and export of energy and international bunker fuels, as discussed in Workbook and Discussion Section 1. At this juncture, however, there is no recommended manner for attributing emissions related to the interstate and international transfer of woody biomass stocks. Also, developing a method for estimating these emissions is hindered by a lack of appropriate data. For example, the commercial timber industry has detailed statistics on activities associated with the export of wood or the production and sale wood products, but state-by-state consumption figures, especially for paper, paper products, and durable wood products, such as furniture, are not well-maintained. This is an area that could benefit from further research and improved consumption statistics.

Forest and Grassland Conversion

- *Delayed Release of Non-CO₂ Trace Gases after Land Disturbance.* An experiment in a temperate northeastern forest in the U.S. found that clear-cutting resulted in enhanced N₂O flux to the atmosphere via dissolution of N₂O in the soil water, transport to surface waters, and degassing from solution (Bowden and Borman, 1986). Conversion of tropical forests to pasture has also been found to result in elevated N₂O emissions relative to intact forest soils (Luizao et al., 1989). Also, the loss of forest area may result in increased net CH₄ emissions to the atmosphere, because soils are a natural sink of CH₄ (*i.e.*, soils absorb atmospheric methane). Various experiments indicate that conversion of forests to agricultural lands diminishes this absorptive capacity (Keller et al., 1990; Scharffe et al., 1990)

Conversion of natural grasslands to managed grasslands and to cultivated lands may not only affect the net emission of CO₂, but CH₄, N₂O, and CO emissions as well. For instance, the conversion of natural grasslands to cultivated lands has been found in the semi-arid temperate zone to also decrease CH₄ uptake by the soils (Mosier et al., 1991). It is not clear what the effect on N₂O would be, unless of course nitrogen fertilization occurs. CO fluxes may be affected due to changes in soil temperature and moisture. These effects on trace gas fluxes, however, are highly speculative.

- *Fate of Roots in Cleared Forests.* The basic calculation ignores the fate of living belowground woody biomass (roots, etc.) after forest clearing. This belowground biomass could be treated as slash, but with perhaps a longer decay time. Alternatively, it might be more reasonable to deal with the belowground biomass in conjunction with soil carbon calculations, as both are likely to involve long time horizons. This is an area for further development.
- *Aboveground Biomass After Conversion.* In the basic calculation, a single default value (22.4 tons dm/acre) is recommended for aboveground biomass which regrows after forests are cleared for conversion to crops or pastures. This may be somewhat variable depending on the types of crop or other vegetation which regrows. State experts carrying out more detailed assessments may wish to account more precisely

for this variability.

Abandoned Lands

- The basic calculations account for only the portion of abandoned lands which regrow toward a natural state. There may be additional releases of carbon from abandoned lands which continue to degrade. Where data are available, analysts doing detailed calculations may wish to account for this phenomenon.

Other Lands

- Several other land-use activities affect the flux of CO₂ and other trace gases between the terrestrial biosphere and the atmosphere. For example, the changing areas and distribution of wetlands may also be adding to or reducing the methane burden to the atmosphere. Freshwater wetlands are a natural source of CH₄, estimated to release 100 - 200 Tg CH₄ per year due to anaerobic decomposition of organic material in the wetland soils (Cicerone and Oremland, 1988). Destruction of freshwater wetlands, through drainage or filling, would result in a reduction of CH₄ emissions, and an increase in CO₂ emissions due to increased oxidation of soil organic material. The magnitude of these effects is largely a function of soil temperature and the extent of drainage (*i.e.*, the water content of the soil). Also, since dryland soils are a sink of CH₄, drainage and drying of a wetland could eventually result in the wetland area changing from a source to a sink of CH₄. Loss of wetland area could also affect net N₂O and CO fluxes, although both the direction and magnitude of the effect is highly uncertain. Some possible methodological approaches for estimating emissions from freshwater wetlands can be found in *IPCC Guidelines for National Greenhouse Gases Inventories, Volume 3* (IPCC, 1994), if states are interested in estimating these emissions. However, currently, no agreed-upon method exists for these source categories.

Some experts have also indicated that changes in surface waters due to human activities can result in sequestration of carbon, and presumably other emissions or removals. An example is pollution of lakes due to runoff, which can cause eutrophication, increasing the carbon content of waters. Pollution of coastal waters could also have similar effects. No data have been obtained thus far to indicate whether the carbon sequestration effects of such changes are significant enough to warrant inclusion in the method.

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DISCUSSION 11

GREENHOUSE GAS EMISSIONS FROM BURNING OF AGRICULTURAL CROP WASTES

OVERVIEW

Large quantities of agricultural crop wastes are produced from farming systems. There are a variety of ways to dispose of these wastes. For example, agricultural residues can be plowed back into the field, composted, landfilled, or burned in the field. Alternatively, they can be collected and used as a biomass fuel or sold in supplemental feed markets. This section addresses field burning of agricultural crop wastes. Field burning of crop wastes is not thought to be a net source of CO₂ because the carbon released to the atmosphere during burning is reabsorbed during the next growing season. Crop residue burning is, however, a net source of CH₄, CO, N₂O, and NO_x, which are released during combustion. In addition, field burning may result in enhanced emissions of N₂O and NO_x many days after burning (Anderson *et al.*, 1988; Levine *et al.*, 1988), although this process is highly uncertain and will not be accounted for in this section. Also, it should be noted that open burning has been banned in some states. States affected by such regulations can ignore this section.

DESCRIPTION OF WORKBOOK METHOD

The methodology for estimating greenhouse gas emissions from field burning of agricultural wastes is based on the amount of carbon burned, emission ratios of CH₄ and CO to CO₂ measured in the smoke of biomass fires, and emission ratios of N₂O and NO_x to the nitrogen content of the fuel. The methodology is presented in workbook form in Workbook Section 11, and in more detail below.

Four types of data are required to calculate the amount of carbon burned in agricultural wastes.

- The amount of crops produced with residues that are commonly burned,
- The ratio of residue to crop product,
- The fraction of residue burned, and
- The carbon content of the residue.

To avoid unrepresentative results based upon fluctuations in economic or climatic conditions, it is recommended that a three-year average (centered on 1990) be used for crop production.

After obtaining the data listed above, the next step in estimating emissions from agricultural waste burning is to multiply annual production data (in pounds) for each of the pertinent crops by the ratio of residue to crop product for each crop, to generate the amount of residue available for combustion. Estimates of residue/crop product ratios for certain crops are presented in Table D11-1.

Next, to calculate the total tonnage of crop residue burned, the total amount of residue produced, for each crop, is multiplied by the fraction of residue burned in the field. If in-state estimates of the amounts of crop residues burned *in situ*, or in the field, are not readily available, it is recommended that a default value of 10 percent be used (U.S. EPA, 1994).

Once the amount of crop residue burned is estimated, it must be converted to dry matter mass units(dm). Dry matter refers to biomass in a dehydrated state.¹ Default values for the percentage of dry matter in crop residues are provided in table D11-1. For example, 200 tons of crop residue with a dry matter content of 91.1 percent, would be equal to 182.2 tons dry matter.

After the total mass of crop residue burned is converted to mass of dry matter burned, the figure must be multiplied by the carbon content per unit of dry matter of the residue to convert to units of carbon. Carbon contents for selected crop residues are presented in Table D11-1; an average value of 0.45 lbs C/lb dm can be used in the cases where data are not available. The steps described above can be combined into the following equation to calculate the total carbon burned:

Equation 1

$$\text{Carbon Burned} = \text{Annual Crop Production (lbs)} \times \text{Residue/Crop Product Ratio} \times \\ \text{Fraction of Residues Burned } in situ (\%) \times \text{Dry Matter Content of} \\ \text{the Residue (\%)} \times \text{Fraction Burned (\%)} \times \text{Carbon Content of the} \\ \text{Residue (lbs C/lbs dm)}^2$$

Once the total carbon burned is estimated, the emissions of CH₄, CO, N₂O, and NO_x can be calculated based on the methodology in Crutzen and Andreae (1990).

To calculate emissions of CH₄ and CO due to burning of crop residue, the amount of carbon burned (Equation 1) is multiplied by the fraction of carbon oxidized to CO₂. Fraction oxidized is defined as the fraction of carbon in the fire that is oxidized completely to CO₂. The default value for fraction oxidized is 0.88 to account for the approximate 12 percent of the carbon that remains on the ground (Seiler and Crutzen, 1980; Crutzen and Andreae, 1990).³ The resulting figure (the amount of carbon dioxide released instantaneously, in units of carbon (CO₂-C)) is then multiplied by the ratios of emissions of CH₄ and CO relative to CO₂ (see Table D11-2)⁴ to yield emissions of CH₄ and CO (each expressed in units of C). The emissions of CH₄ and CO are then multiplied by 16/12 and 28/12, respectively, to convert to full molecular weights.

¹ According to Elgin (1991), the moisture content of crop residue varies depending on the type of crop residue, climatic conditions (*i.e.*, in a humid environment the residue will retain more moisture than in an arid environment), and the length of time between harvesting and burning of the residue.

² Fraction burned is defined as the fraction of dry biomass exposed to burning that actually burns.

³ This estimate of the carbon exposed to burning that remains on the ground is probably some combination of charcoal and unburned material that gets reincorporated into the soil during field preparation for the next crop. The charcoal represents a long-term sink of carbon, and in a complete accounting of carbon flows, would be treated as such. The unburned material represents carbon that may be reabsorbed by next year's crops or emitted as CO₂ or remain in the soil. The 12 percent estimate is highly uncertain; the fractions of this estimate that are charcoal and unburned material have never been measured nor estimated. Because of the uncertainty and lack of data surrounding these "carbon flows," no attempt will be made to incorporate them in the methodology at this time.

⁴ Table D11-2 provides suggested default values for non-CO₂ trace gas emissions. These are presented with ranges to emphasize their uncertainty.

Table D11-1
Selected Crop Residue Statistics

Product	Residue/Crop Product	Dry Matter (%)	Nitrogen/Carbon Ratio (lbs N/lbs C)	Carbon Content (% dm)
Cereals				
Wheat	1.3	91.1	0.0082	48.53
Barley	1.2	90.4	0.0026	45.67
Maize	1.0	88	0.0172	47.09
Oats	1.3	90.6	0.0144	48.53
Rye	1.6	90	0.0144	48.53
Rice	1.4	90	0.0162	41.44
Millet	1.4	88.5	0.0144	48.53
Sorghum	8.0	90	0.0175	48.53
Legumes				
Pea	1.5	90.2	0.0511	45
Bean	2.1	88.7	0.0511	45
Lentils	2.1	88.3	0.0511	45
Soya	2.1	89.3	0.0511	45
Tuber and Root Crops				
Potatoes	0.4	86.7	0.026	42.26
Feedbeet	0.4	86.7	0.026	40.72 ¹
Sugarbeet	0.3	90	0.056	40.72 ¹
Jerusalem Artichoke	0.8	90	0.026	42.46
Peanut	1.0	90.1	0.026	42.46
Sugarcane	0.8	90	0.0064	46.95

¹ These statistics are for beet leaves.

Source: U.S. EPA, 1994.

To calculate emissions of N_2O and NO_x due to burning of crop residue, the amount of carbon burned (Equation 1) is multiplied by the fraction of carbon oxidized to CO_2 (*i.e.*, 0.88) and the nitrogen/carbon ratio (the N/C ratio of the fuel by weight; the nitrogen/carbon ratios of selected residues are provided in Table D11-1). This yields the total amount of nitrogen released (Crutzen and Andreae, 1990); see Equation 2). The total N released is multiplied by the ratios of emissions of N_2O and NO_x relative to the N content of the fuel (see Table D11-2) to yield emissions of N_2O and NO_x expressed in units of N. To convert to full molecular weights, the emissions of N_2O and

NO_x are multiplied by 44/28 and 46/14, respectively.⁵

Equation 2

$$\text{Nitrogen Released} = \text{Carbon Burned (lbs C)} \times \text{Fraction Oxidized (\%)} \times \text{Nitrogen/Carbon Content of the Residue (lbs N/lbs C)}$$

UNCERTAINTIES

The method presented here provides relatively crude estimates with substantial uncertainties. Use of specific emission ratios, which vary by type of burning, region, etc., may allow for more precise calculations. The ratios presented here are based on measurements taken in a wide variety of fires. In many cases, these ratios are general averages for all biomass burning. Research will need to be conducted in the future to determine if more specific emission ratios, e.g., specific to the type of biomass and burning conditions, can be obtained. Also, emission ratios vary significantly between the flaming and smoldering phases of a fire. CO_2 , N_2O , and NO_x are mainly emitted during the flaming stage, while CH_4 and CO are mainly emitted during the smoldering stage. The relative importance of these two stages will vary between fires in different ecosystems and under different climatic conditions, and so the emission ratios will vary.

Another issue that should be noted is that the basic calculations described here ignore the contemporary fluxes associated with past burning activities. These releases are known to exist, but are poorly understood at present. There are also other issues currently not treated in these calculations. For example, long-term changes in soil carbon are certainly possible as a result of agricultural practices. In fact, depending on the specific agricultural soil management practices used, including burning, there may be a variety of effects on soil carbon. In fact, repeated burning of crop residues in fields can cause an increase in the amount of carbon stored in the soil over time. The effect of past burning on current emissions is one such issue. The longer-term release and uptake of these gases following burning is an important research issue and may be included in future refinements of the calculations.

Table D11-2. Emission Ratios for Biomass Burning Calculations

Compound	Ratios
CH_4	0.003
CO	0.06 (0.04 - 0.08)
N_2O	0.007 (0.005 - 0.009)
NO_x	0.121 (0.094 - 0.148)

Source: Crutzen and Andreae, 1990.

Note: Ratios for carbon compounds, i.e., CH_4 and CO, are mass of carbon compound released (in units of C) relative to mass of CO_2 released from burning (in units of C); those for the nitrogen compounds are expressed as the ratios of emission relative to the nitrogen content of the fuel.

⁵ However, the numbers used to convert NO_x emissions to full molecular weight are based on the assumption that all of the NO_x emissions are NO_2 , because NO is assumed to quickly oxidize to NO_2 : Andreae (1990) noted that NO is the primary form of NO_x emitted during biomass combustion.

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DISCUSSION 12

METHANE EMISSIONS FROM MUNICIPAL WASTEWATER

OVERVIEW

Disposal and treatment of industrial and municipal wastewater can produce emissions of most of the important greenhouse gases. Wastewater can be treated using aerobic and/or anaerobic technologies, or if untreated, can degrade under either aerobic or anaerobic conditions. Methane is produced when organic material in treated and untreated wastewater degrades anaerobically, i.e., without the presence of oxygen. Highly organic wastewater streams such as waste streams from food processing or pulp and paper plants rapidly deplete available oxygen in the water stream as their organic matter decomposes. The organic content, otherwise known as "loading" of these wastewater streams, is expressed in terms of biochemical oxygen demand, or "BOD."¹ BOD represents the amounts of oxygen taken up by the organic matter in the wastewater during decomposition. Under the same conditions, wastewater with higher BOD concentrations will produce more methane than wastewater with relatively lower BOD concentrations. Most industrial wastewater has a low BOD content, while food processing facilities such as fruit, sugar, meat processing plants, and breweries can produce untreated waste streams with high BOD content.

Although recommended methodologies for estimating methane emissions from municipal and industrial wastewater exist, the data required by these methodologies are not easily obtained. This is especially true for data related to industrial wastewater. The methodology for estimating emissions from industrial wastewater is presented here, but because of the difficulty in obtaining data, estimating emissions from this source is optional and, therefore, is not presented in Workbook Section 12.

DESCRIPTION OF WORKBOOK METHOD

Municipal Wastewater

To estimate methane emissions from municipal wastewater, the following steps are required: 1) obtain the required data on state population; 2) estimate biochemical oxygen demand (BOD_5); 3) estimate gross annual methane emissions; and (4) estimate net annual methane emissions. A detailed, step-by-step description of the methodology is provided in Workbook Section 12.

The simple methodology for calculating emissions from municipal wastewater treatment is based on BOD loading and relies on state-specific data. The data needed for using this approach includes information on BOD_5 per capita per day. If state-specific information is not available, a default value of 0.1356 lbs/capita/day can be used. State population data, the fraction of total

¹ A standardized measurement of BOD is the "5-day test" denoted as BOD_5 . Under the same conditions, wastewater with higher BOD concentrations will yield more CH_4 than wastewater with relatively lower BOD concentrations. Because of its influence on CH_4 , BOD is a commonly measured parameter and in-state data on BOD loading rates should be available. If this is not the case, then a default value of 0.1356 lbs/capita/day can be used.

wastewater that is treated anaerobically (if in-state data are not available, a default value of 15 percent can be used), and the amount of methane that is recovered is also required. This information can be plugged into equation 12-1 presented below to estimate emissions from this source.

(12.1) Methane Emissions from Municipal Wastewater — Simplified Approach

$$\frac{\text{lbs } CH_4}{\text{year}} = (\text{Population}) \left(\frac{\text{lbs } BOD_s}{\text{capita/day}} \right) \left(\frac{365 \text{ days}}{\text{yr}} \right) \left(\frac{0.22 \text{ lbs } CH_4}{\text{lbs } BOD_s} \right) \left(\frac{\text{Fraction Anaerobically Digested}}{} \right)$$

ALTERNATE METHODOLOGY

Municipal Wastewater

A more detailed method exists to obtain more accurate emission estimates, but more detailed data are required. Therefore, a more precise estimate of methane emissions from wastewater treatment for a given state is possible, if the following additional data are available: (1) the different wastewater treatment methods used in each state; (2) the total portion of wastewater that is treated using each of these methods; and (3) the methane conversion factor (MCF) of each of these treatment methods (the MCF represents the extent to which the maximum methane producing capacity of wastewater is realized for a given wastewater treatment system).

Where data are available, the following equation would be used to estimate methane emissions:

(12.2) Methane Emissions from Municipal Wastewater — Complex Method

$$\frac{\text{lbs } CH_4}{\text{year}} = (\text{Population}) \left(\frac{\text{lbs } BOD_s}{\text{capita/day}} \right) \left(\frac{365 \text{ days}}{\text{yr}} \right) \left(\frac{0.22 \text{ lbs } CH_4}{\text{lbs } BOD_s} \right) \left(\begin{array}{c} \text{Fraction Wastewater} \\ \text{Treated} \\ \text{Using Method}_i \end{array} \right) \left(\begin{array}{c} \text{MCF for} \\ \text{Method}_i \end{array} \right) - \left(\begin{array}{c} \text{Methane} \\ \text{Recovered} \end{array} \right)$$

Unfortunately, many states may not have data on the portion of wastewater treated using different methods. Additionally, at this time, complete information on MCFs for different wastewater treatment systems is not available. States which have more detailed information on specific methods treatment and their corresponding MCFs are encouraged to use this information in preparing state inventories.

Industrial Wastewater

To estimate methane emissions from industrial wastewater treatment, the following data are required:

- Relevant industries within a state;
- Amount of wastewater outflow by industry;

- Concentration of organic material in the wastewater;
- BOD content of wastewater;
- Amount of wastewater anaerobically treated; and
- Methane recovered.

After the relevant data have been obtained, then emissions can be estimated in the same manner as emissions from the treatment of municipal wastewater:

Step 1: Wastewater outflow by industry must be estimated. If these data are not directly available, they may be estimated based on the production by industry, and waste consumed per unit of product. Typical water consumption rates for some key industries are presented in Table D12-1.

Step 2: The BOD₅ content of the wastewater for each product must be estimated. Default BOD₅ values are provided in Table D12-2.

Step 3: Estimate the fraction of wastewater from each industry that is treated anaerobically. Unfortunately, default values are not available by industry.

Step 4: If anaerobic treatment with methane recovery is employed, the amount of methane recovered should be subtracted from total emissions.

Step 5: Total methane emissions from this source are estimated by summing the methane emission estimates for each industry across all relevant industries in the state.

The following equation summarizes the emissions calculation for industrial wastewater treatment:

(12.3) Methane Emissions from Industrial Wastewater — Simplified Approach

$$\sum_{I_i} \frac{\text{lbs } CH_4}{\text{year}} = \left(\begin{array}{l} \text{Wastewater Outflow} \\ \text{by Industry} \end{array} \right) \left(\frac{\text{lbs } BOD_5}{\text{Gallon}} \right) \left(\frac{0.22 \text{ lbs } CH_4}{\text{lbs } BOD_5} \right) \left(\begin{array}{l} \text{Fraction} \\ \text{Anaerobically} \\ \text{Treated} \end{array} \right) - \left(\begin{array}{l} \text{Methane} \\ \text{Recovered} \end{array} \right)$$

As with methane emissions from municipal wastewater treatment, more precise estimates of methane emissions from industrial wastewater treatment can be made if specific methods used to treat wastewater flow from each industry are known and the MCFs for each method have been estimated. If this information is available, the following equation can be used:

(12.4) Methane Emissions from Industrial Wastewater — Complex Method

$$\sum_{I_i} \frac{\text{lbs } CH_4}{\text{year}} = \left(\begin{array}{l} \text{Wastewater Outflow} \\ \text{by Industry} \end{array} \right) \left(\frac{\text{lbs } BOD_5}{\text{Gallon}} \right) \left(\frac{0.22 \text{ lbs } CH_4}{\text{lbs } BOD_5} \right) \left(\begin{array}{l} \text{Fraction Wastewater} \\ \text{Treated} \\ \text{Using Method}_i \end{array} \right) \left(\begin{array}{l} \text{MCF for} \\ \text{Method}_i \end{array} \right) - \left(\begin{array}{l} \text{Methane} \\ \text{Recovered} \end{array} \right)$$

UNCERTAINTIES

There is uncertainty in estimating emissions from wastewater due to a lack of data characterizing wastewater management practices, the quantities of wastewater that are subject to anaerobic conditions, the extent to which methane is emitted under anaerobic conditions, and flaring or utilization practices. For example, methane production varies depending upon temperature, retention time, BOD loading, and lagoon maintenance and depth.²

Table D12-1. Water Consumption Per Unit for Selected Industries

Process	Water Consumption (Gallons/Ton)
Canneries	
Green Beans	19,174
Peaches and Pears	5,273
Other fruits and vegetables	5,752
Food and Beverage	
Beer	14,381
Wine	4,794
Meat Packing	4,314
Pulp and Paper	
Pulp	156,991
Paper	47,936
Textiles	
Bleaching	83,888
Dyeing	14,381

Source: IPCC, 1994

² Facultative and anaerobic lagoons are often used for storage and treatment. EPA estimated in 1987 that there were approximately 5,500 municipal waste stabilization lagoons in the U.S. The CH₄ potential from these lagoons is not well understood and little field data are available. Industrial and commercial wastewater processes also use lagoons for treatment and storage. Facultative lagoons, the most common type, treat wastewater by both anaerobic fermentation and aerobic processes. At the bottom of the lagoon, where an anaerobic environment exists, organic matter is digested to CH₄ and CO₂. As these gases bubble to the surface, much of the CO₂ is absorbed by algae and is used, along with nutrients liberated during digestion, to produce algal biomass. Aerobic conditions, supported by algae growth, are maintained near the surface. Between 20 and 30 percent of the BOD loading to a facultative pond is anaerobically metabolized. As BOD loading increases and natural surface aeration diminishes, facultative lagoons proceed to a more anaerobic state. This results in higher CH₄ production, providing that the temperature is higher than 59°F. Under these conditions, a facultative lagoon may act more as an anaerobic pond, with possibly 95 percent of the lagoon volume functioning anaerobically. Fermentation, and this CH₄ production, is negligible at temperatures below about 59°F, at which point the lagoons serve principally as a sedimentation tank.

Wastewater treatment is also now being studied as a source of N₂O, although there is currently no methodology to estimate N₂O emissions from this source. The effluent of wastewater treatment plants and all other waste that is disposed of in surface water can also lead to methane and nitrous oxide emissions from inland and coastal waters. The same applies to untreated sewage or excess manure and fertilizer application. Runoff can lead to surface water pollution and related methane and nitrous oxide emissions. However, methods for estimating emissions from these sources are not available at this time. Future evaluation of ongoing research will give an indication of the importance of these sources and perhaps provide a method for use by states.

Table D12-2. BOD₅ for Selected Industries

Industry	BOD ₅ (lbs/gallon)
Iron and Steel	0.008
Non-Ferrous Metals	0.008
Fertilizer	0.008
Food and Beverage	0.292
Pulp and Paper	0.033
Petroleum Refining	0.003
Textile	0.008
Rubber	0.008
Miscellaneous	0.017

Source: IPCC, 1994.

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DISCUSSION 13

OTHER GREENHOUSE GAS EMISSIONS FROM MOBILE COMBUSTION

OVERVIEW

This section discusses emissions of greenhouse gases from mobile sources, including carbon monoxide (CO), nitrogen oxides (NO_x), methane (CH_4), nitrous oxide (N_2O), and non-methane volatile organic compounds (NMVOCs). The reader should note before proceeding with this section that these calculations can be time consuming and complex. Moreover, the amount of gases emitted from these activities are not thought to be major contributors to climate change. Additionally, data on gases such as CO, NO_x , and NMVOCs may already be collected by state environmental agencies to determine state compliance with the Clean Air Act or other regulations. For these reasons a methodology for this source category was not included in the workbook.

Emissions from mobile sources are most easily estimated by major transport activity, *i.e.*, road, air, rail, and ships. Several major fuel types need to be considered, including gasoline, diesel, jet fuel, aviation fuel, natural gas, liquified petroleum gas, and residual fuel oil. Road transport accounts for the majority of mobile source fuel consumption (*e.g.*, U.S. demand for oil accounts for 50 percent of the worldwide total), followed by air transport. This indicates that the primary emphasis in developing emission factors should be placed on road vehicles, followed by aircraft.

If transport fuels (mostly composed of hydrocarbons [HC]) were completely combusted, the only products emitted would be CO_2 and H_2O . However, under actual conditions, not all the fuel is completely combusted, resulting in the formation of other gases. For example, motor vehicles emit a large portion of total anthropogenic NO_x emissions. NO_x emissions are closely related to air-fuel mixes and combustion temperatures, as well as pollution control equipment. For uncontrolled vehicles, NO_x emissions from diesel-fueled vehicles are generally lower than from gasoline-fueled vehicles. In terms of tons of emissions per ton-mile transported, heavy duty vehicles (HDV) are more efficient than light duty vehicles (LDV), but HDV still contribute a significant share of motor vehicle NO_x emissions. Moreover, HDV are more difficult to control than LDV and are generally subject to less stringent emission control regulations.

The majority of CO emissions from fuel combustion comes from motor vehicles. CO emissions, even more so than CH_4 emissions, are a function of the efficiency of combustion and post-combustion emission controls. Like CH_4 emissions, CO emissions are highest when air-fuel mixtures are "rich," with less oxygen than required for complete combustion. This occurs especially in idle, low speed, and cold start conditions in spark ignition engines.

Methane emissions and NMVOCs from motor vehicles are a function of the methane content of the motor fuel, the amount of hydrocarbons passing unburnt through the engine, and any post-combustion control of hydrocarbon emissions, such as use of catalytic converters. The emissions of unburned HC, including CH_4 , are lowest in uncontrolled engines when the quantity of hydrogen, carbon, and oxygen are present in exactly the right combination for complete combustion (the "stoichiometric ratio"). Thus, CH_4 and NMVOC emissions will be determined by the air-fuel ratio. They are generally highest in low speed and engine idle conditions. Poorly tuned engines may have

particularly high output of total HC, including CH₄. Emissions are also strongly influenced by the engine type and the fuel combusted.

For more information on greenhouse gas emissions from mobile sources, the reader is referred to Mark DeLuchi's *Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity*, published by the Argonne National Laboratory (November 1991).

DESCRIPTION OF METHOD

An estimation of mobile source emissions is a very complex undertaking that requires consideration of many parameters, including information on such factors as:

- transport class
- fuel consumed
- operating characteristics
- emission controls
- maintenance procedures
- fleet age
- other factors

The need for data on several parameters and the wide variety of conditions that can affect the performance of each category of mobile sources makes it very difficult to generalize the emission characteristics in this area.

Nevertheless, a minimum emission estimation methodology, as discussed below, is suitable as a starting point for states to establish emissions estimations. In fact, the complexity of this issue makes it difficult even for states with extensive experience to develop highly-precise emission inventories. As such, it may be appropriate to avoid excessive complexity with any starting emission estimation methodology.

In order to develop a minimum estimation method for greenhouse gas emissions from mobile sources, basic information is required on the types of fuels consumed in the transport sector, the combustion technologies that are used to consume the fuels, operating conditions during combustion, and the extent of emission control technologies employed during and after combustion. The basic approach for estimating these emissions is presented in the following equation:

$$\text{Emissions} = \sum (\text{EF}_{abc} \times \text{Activity}_{abc})$$

where Emissions are in pounds of pollutant;

EF = emissions factor (lbs/mile, lbs/ton fuel, or lbs/10⁶ Btu);

Activity = amount of energy consumed (miles, tons fuel, or 10⁶ Btu);

a = transport mode (rail, road, air, water);

b = fuel type (diesel, gasoline, LPG¹, etc.); and

c = vehicle type (passenger car, light duty truck, train, etc.).

¹ LPG refers to liquified petroleum gas.

Basic Methodology

Using this general equation, the following basic steps are required to estimate mobile source emissions:

- Step 1:** Determine the amount of energy consumed by energy type for all mobile sources using data from state energy or transportation agencies, the U.S. EPA, U.S. DOE, or other data sources (all values should be reported in million Btu).
- Step 2:** For each energy type, determine the amount of energy that is consumed by each vehicle and technology type, *e.g.*, gasoline passenger cars, light-duty diesel trucks, etc. (all units are in million Btu).
- Step 3:** Determine the percentage of each vehicle type that has some form of emission control technology. If only a portion of the energy consumed by a particular vehicle type has emission control technology, then only the energy attributable to this portion of the vehicle stock should be identified as subject to emission controls.
- Step 4:** Multiply the amount of energy consumed by each vehicle type by the appropriate emissions factors from Tables D13-2 through D13-12. If some or all of a vehicle type uses emission controls (as determined in the previous step), emissions factors for these portions should reflect the appropriate level of emission control. For example, the NO_x emission factor for energy consumed by gasoline passenger cars using three way catalyst control would be 0.0018 lbs/mile.
- Step 5:** To obtain total emissions from mobile sources, sum vehicle/technology emissions estimates across all fuel and technology type categories, including all levels of emission control.

Regardless of the specific methodology that is used to determine emissions, it is important to remember that there is a substantial amount of uncertainty surrounding the estimation of emissions from mobile sources, much of which is a result of uncertainty in emission factors. Some means should be developed to rank the differences in data quality and the uncertainties affecting emission estimates. This may involve the use of standard deviations, ranges of uncertainty, or some other means of indicating to the data consumer the relative reliability of the data.

Emission Factors

This section presents mobile source emission factors for gases contributing to global warming. Emission factor estimates have been developed for CO, NO_x, N₂O, methane, and non-methane VOCs for several classes of highway vehicles, railway locomotives, ships and boats, farm and construction equipment, and aircraft. This discussion is taken from Weaver and Turner (1991). States are highly encouraged to identify and discuss with in-state experts if more appropriate in-state emission factors are available.

Highway Vehicles - Conventional Fuels

Technical Approach. The emissions estimates developed for NO_x, CO, methane, and NMVOCs from highway vehicles were based on the U.S. EPA's MOBILE4 model (EPA, 1989). This

model, the most widely used emission factor model in the U.S., reflects more than a decade of development, and incorporates the results of emissions tests on more than 10,000 vehicles in customer use performed over the last 20 years.² In addition to testing under standard conditions, many of these tests have included emissions measurements at other temperatures, with different grades of fuel, and under different driving cycles. Much less effort has been expended on testing and modeling of heavy-duty vehicle emissions than those from light-duty vehicles, so that the emission factor estimates for these vehicles are considered less reliable.

MOBILE4 calculates exhaust emission factors for U.S. vehicles using gasoline and diesel fuel, based on the year in which they were manufactured. For gasoline vehicles, it also calculates VOC emissions due to evaporative, running, and refueling losses (VOC emissions from diesel vehicles due to these causes are negligible). To develop emissions estimates for different emission control technology types, calculations were carried out for specific model years during which U.S. vehicles were equipped with the technology in question. To reflect normal in-use deterioration over the vehicle's life, emissions were calculated for each vehicle type when they were five years old, or approximately halfway through their useful lives. For example, estimates of uncontrolled passenger vehicle emissions were based on MOBILE4 results for model year 1963 vehicles in calendar year 1968, when they would be five years old. Similarly, emissions estimates for advanced-technology vehicles were based on 1990 U.S. model vehicles, calculated under 1995 operating conditions. Table D13-1 shows the correlation between technology types and the U.S. model years used to represent them in the model.

The emission factors calculated by MOBILE4 are affected by the assumptions regarding average speeds, ambient temperature, diurnal temperature range, altitude, and fuel volatility that are used in the model. They are also affected by the assumed presence or absence of inspection/maintenance and anti-tampering programs. Since it would not be possible to represent the state diversity in these conditions in a single set of factors, the conditions chosen for the modeling were "typical" values of 75 °F, with a diurnal range from 60 to 85 °F (24 ± 8 °C), and Reid vapor pressure of gasoline at 9.0 PSI (62 kPa). Average speed was taken as the MOBILE4 default of 19.5 mph, typical of uncongested urban driving.

Changes in these input assumptions would change the resulting emission factors. Exhaust pollutant emission factors increase markedly at low temperatures, while evaporative VOC emissions decrease with temperature. Exhaust emissions in lbs/mile also tend to rise with decreasing average speed, due mostly to the increase in fuel consumption/mile. Evaporative VOC emissions tend to increase with increasing gasoline volatility and increasing diurnal temperature range.

In order to reflect the emissions control *potential* of the different technologies, we assumed an effective inspection/maintenance and anti-tampering program, which would help to assure that the vehicle emission controls were in place and functioning as designed. This assumption may result in some under-estimation of *actual* emissions from emission-controlled vehicles, since not all vehicles are subject to such effective standards.

The estimated vehicle fuel economies were also used to calculate fuel-specific (lbs/ton fuel) and energy-specific (lbs/ 10^6 Btu) emission factors for all of the pollutants. Since emissions and fuel consumption tend to vary in parallel (vehicles and operating modes causing high emission rates also

² A new version of this model, MOBILE5, has recently been introduced. Information from MOBILE5 was not readily available at the time this report was prepared.

tend to result in high fuel consumption, and vice versa), these energy-specific emission factors are expected to be more generally applicable than the factors in lbs/mile, and use of these factors rather than the lbs/mile values is recommended.

Since MOBILE4 does not estimate N₂O emissions, it was necessary to develop separate estimates of these. N₂O formation in internal combustion engines is not yet well understood, and data on these emissions are scarce. It is believed, with substantial evidence, that N₂O emissions come from two distinct processes. The process occurs during the actual combustion process in the cylinder. It is believed that the major contributor is the interaction of NO with combustion intermediates such as NH and NCO. This N₂O is then very rapidly removed in the post-flame gas by the reaction between N₂O and hydrogen. While a significant amount of N₂O may be formed in the flame, it can only survive if there is very rapid quenching of the gases, which is not common. Thus, only very small amounts of N₂O are produced as engine-out emissions.

The N₂O forming process occurs during catalytic aftertreatment of exhaust gases. Otto, Shelef, and Kummer (1970) have shown that N₂O is produced during the reaction of NO and NH₃ over the platinum in the catalytic converter. The order of magnitude for the maximum NO conversion into N₂O was about 5 to 10 percent. The output of N₂O from the catalyst is highly temperature dependent. Prigent and De Soete (1989) showed that as the catalyst warmed up after a cold start, N₂O levels increased heavily (4.5 times the inlet value) at around 360°C. The emissions then decreased to the inlet level at a catalyst temperature of 460°C. Above this temperature there is less N₂O from the catalyst downstream than upstream. N₂O emissions are thus formed primarily during cold starts of catalyst-equipped vehicles. Comparison of N₂O emissions data for the U.S. Highway Fuel Economy Test (HFET) with that for the Federal Test Procedure (FTP) shows much lower N₂O emissions. The FTP contains a cold-start phase, while the HFET does not.

Several methods were used to estimate N₂O emission factors for this study. Prigent and De Soete (1989), Dasch (1991), Ford (1989-1991), and Warner-Selph and Smith (1991) gave N₂O

Table D13-1: Emission Control Technology Types and U.S. Vehicle Model Years Used to Represent Them.

Technology	Model Year
Gasoline Passenger Cars and Light Trucks	
Uncontrolled	1963
Non-catalyst controls	1972
Oxidation catalyst	1978
Early three-way catalyst	1983
Advanced three-way catalyst	1990
Heavy-Duty Gasoline Vehicles	
Uncontrolled	1968
Non-catalyst control	1983
Three-way catalyst	1991
Diesel Passenger Cars and Light Trucks	
Uncontrolled	1978
Moderate control	1983
Advanced control	1990
Heavy Duty Diesel Vehicles	
Uncontrolled	1968
Moderate Control	1983
Advanced control	1991
Motorcycles	
Uncontrolled	1972
Non-catalyst controls	1990

emissions for light-duty gasoline vehicles equipped with different catalyst technologies. The different catalyst types were divided into four groups: uncontrolled, oxidation catalyst, early three-way catalyst, and modern three-way catalyst technologies. The FTP emissions data from these studies were combined and averaged to determine the mean N₂O emissions from light-duty vehicles equipped with each technology. These numbers were used directly to estimate N₂O emissions from gasoline passenger cars. For light-duty gasoline trucks and motorcycles, fuel-specific N₂O emissions were assumed to be the same as for the corresponding passenger car technology. N₂O emissions per kilometer were then calculated from the fuel-specific emissions and the fuel consumption characteristics for each class.

No data on N₂O emissions from heavy-duty gasoline trucks were available. Therefore, since the engines used in these vehicles are fairly similar to those in passenger cars, it was decided to approximate the N₂O emissions by assuming that emissions per unit of fuel burned would be similar to those for passenger cars having similar technology. However, since these trucks undergo a heavier duty cycle, and experience fewer cold-starts, it was considered more appropriate to use N₂O emission factors based on the U.S. highway fuel economy test (HFET) rather than the cold-start FTP procedure. Fuel-specific emissions N₂O emissions for passenger cars in the HFET procedure were obtained from the same data sources listed above.

Dietzmann, Parness, and Bradow (1980) reported N₂O emissions data for four heavy-duty diesel trucks, including a range of representative engines. The average of these data was used directly as the N₂O emission factor for heavy-duty diesel vehicles. No N₂O emissions data were available for light-duty diesel vehicles. N₂O emissions for diesel passenger cars and light-duty trucks were estimated by assuming the same fuel-specific emission rates as for heavy-duty diesels.

Light-duty gasoline passenger cars. The U.S. EPA considers a passenger car to be any vehicle with rated gross vehicle weight less than 8,500 lb (3,855 kg) designed primarily to carry 12 or fewer passengers, and not possessing special features such as four wheel drive for off-road operation. Table D13-2 summarizes the estimated emission factors for gasoline passenger cars. Estimates for five levels of gasoline-vehicle control technology are shown. These technology levels range from completely uncontrolled (still typical of most vehicles around the world) through non-catalyst emission controls, oxidation catalysts, and two levels of three-way catalyst control. Non-catalyst emission controls include modifications to ignition timing and air-fuel ratio to reduce emissions, exhaust gas recirculation (EGR), and air-injection into the exhaust manifold. Oxidation catalyst systems normally include many of the same techniques, plus a two-way catalytic converter to oxidize HC and CO. The "early" three-way catalyst results are representative of those for vehicles sold in the U.S. in the early to mid '80s, which were mostly equipped with carburetors having electronic "trim". The "advanced" three-way catalyst values are based on current U.S. technology vehicles, using electronic fuel injection under computer control.

Light-duty gasoline trucks. Light-duty trucks are defined as vehicles having rated gross vehicle weight less than 8,500 lb (3,855 kg), and which are designed primarily for transportation of cargo or more than 11 passengers at a time, or which are equipped with special features for off-road operation. They include most pickup trucks, passenger and cargo vans, four-wheel drive vehicles, and derivatives of these. The engine and other technologies used in these vehicles are basically similar to those used in passenger cars, but these vehicles usually have larger engines, poorer fuel economy, and somewhat higher emissions. Table D13-3 summarizes the estimated pollutant emissions for this vehicle class. The technology classifications used are the same as those for gasoline passenger vehicles.

Table D13-2: Estimated Emissions Factors for Gasoline Passenger Cars

EMISSIONS					
	NO _x	CH ₄	NMVOC	CO	N ₂ O
Advanced Three-Way Catalyst Control					
Total - lbs/mile	0.0018	0.00007	0.0023	0.0111	0.00007
Exhaust	0.0018	0.00007	0.0009	0.0111	0.00007
Evaporative			0.0004		
Refueling			0.0005		
Running loss			0.0005		
lbs/ton fuel	15.88	0.64	20.96	99.74	0.60
lbs/10 ⁶ Btu	0.398	0.016	0.530	2.497	0.015
Early Three-Way Catalyst					
Total - lbs/mile	0.0018	0.00014	0.0024	0.0111	0.00016
Exhaust	0.0018	0.00014	0.0009	0.0111	0.00016
Evaporative			0.0004		
Refueling			0.0006		
Running loss			0.0005		
lbs/ton fuel	12.98	1.00	16.72	77.86	1.14
lbs/10 ⁶ Btu	0.331	0.025	0.420	1.945	0.029
Oxidation Catalyst					
Total - lbs/mile	0.0056	0.00032	0.0062	0.0461	0.00010
Exhaust	0.0056	0.00032	0.0040	0.0461	0.00010
Evaporative			0.0007		
Refueling			0.0007		
Running loss			0.0008		
lbs/ton fuel	25.26	1.42	27.80	206.14	0.42
lbs/10 ⁶ Btu	0.641	0.036	0.707	5.171	0.011
Non-Catalyst Control					
Total - lbs/mile	0.0070	0.00062	0.0112	0.0844	0.000018
Exhaust	0.0070	0.00062	0.0076	0.0844	0.000018
Evaporative			0.0016		
Refueling			0.0010		
Running loss			0.0010		
lbs/ton fuel	31.28	2.76	50.02	377.97	0.08
lbs/10 ⁶ Btu	0.796	0.069	1.260	9.502	0.002
Uncontrolled					
Total - lbs/mile	0.0076	0.00062	0.0225	0.1441	0.000018
Exhaust	0.0076	0.00062	0.0155	0.1441	0.000018
Evaporative			0.0049		
Refueling			0.0010		
Running loss			0.0011		
lbs/ton fuel	33.98	2.76	100.54	645.11	0.08
lbs/10 ⁶ Btu	0.862	0.069	2.519	16.198	0.002

Table D13-3: Estimated Emission Factors for Light-Duty Gasoline Trucks.

EMISSIONS					
	NO _x	CH ₄	NMVOC	CO	N ₂ O
Advanced Three-Way Catalyst Control					
Total - lbs/mile	0.0024	0.00014	0.00266	0.0166	0.000085
Exhaust	0.0024	0.00014	0.00142	0.0166	0.000085
Evaporative			0.00035		
Refueling			0.00071		
Running loss			0.00014		
lbs/ton fuel	16.72	1.00	18.72	116.80	0.60
lbs/10 ⁶ Btu	0.420	0.025	0.464	2.939	0.015
Early Three-Way Catalyst;					
Total - lbs/mile	0.0035	0.00025	0.00415	0.0327	0.000224
Exhaust	0.0035	0.00025	0.00277	0.0327	0.000224
Evaporative			0.00046		
Refueling			0.00075		
Running loss			0.00014		
lbs/ton fuel	18.16	1.28	21.24	167.52	1.14
lbs/10 ⁶ Btu	0.464	0.032	0.530	4.199	0.029
Oxidation Catalyst					
Total - lbs/mile	0.0057	0.0003	0.0069	0.0431	0.00011
Exhaust	0.0057	0.0003	0.0043	0.0431	0.00011
Evaporative			0.0008		
Refueling			0.0010		
Running loss			0.0008		
lbs/ton fuel	22.06	1.22	26.54	165.40	0.42
lbs/10 ⁶ Btu	0.552	0.031	0.663	4.154	0.011
Non-Catalyst					
Total - lbs/mile	0.0100	0.0006	0.0161	0.1022	0.00002
Exhaust	0.0100	0.0006	0.0107	0.1022	0.00002
Evaporative			0.0032		
Refueling			0.0012		
Running loss			0.0010		
lbs/ton fuel	38.38	2.36	61.94	392.17	0.08
lbs/10 ⁶ Btu	0.972	0.059	1.547	9.856	0.002
Uncontrolled					
Total - lbs/mile	0.0093	0.0006	0.0303	0.1581	0.00002
Exhaust	0.0093	0.0006	0.0177	0.1581	0.00002
Evaporative			0.0104		
Refueling			0.0011		
Running loss			0.0011		
lbs/ton fuel	35.80	2.36	116.26	606.45	0.08
lbs/10 ⁶ Btu	0.906	0.059	2.917	15.225	0.002

Table D13-4: Estimated Emission Factors for Heavy-Duty Gasoline Vehicles.

EMISSIONS					
	NO _x	CH ₄	NMVOC	CO	N ₂ O
Three-Way Catalyst Control					
Total - lbs/mile	0.0094	0.00035	0.00557	0.0299	0.00002
Exhaust	0.0094	0.00035	0.00244	0.0299	0.00002
Evaporative			0.00115		
Refueling			0.00121		
Running loss			0.00078		
lbs/ton fuel	20.14	0.76	11.98	64.32	0.04
lbs/10 ⁶ Btu	0.508	0.022	0.309	1.613	0.001
Non-Catalyst Control					
Total - lbs/mile	0.0122	0.00062	0.0179	0.1427	0.00002
Exhaust	0.0122	0.00062	0.0077	0.1427	0.00002
Evaporative			0.0078		
Refueling			0.0013		
Running loss			0.0011		
lbs/ton fuel	25.96	1.30	16.24	302.64	0.04
lbs/10 ⁶ Btu	0.641	0.022	0.398	7.602	0.001
Uncontrolled					
Total - lbs/mile	0.0203	0.0013	0.0644	0.5078	0.00003
Exhaust	0.0203	0.0013	0.0409	0.5078	0.00003
Evaporative			0.0204		
Refueling			0.0020		
Running loss			0.0011		
lbs/ton fuel	31.08	2.04	98.88	779.35	0.04
lbs/10 ⁶ Btu	0.773	0.044	2.475	19.579	0.001

Heavy-duty gasoline vehicles. A heavy-duty vehicle is defined as one having a manufacturer's gross vehicle weight rating exceeding 8,500 lb (3,855 kg). In the U.S., this includes a number of models of large pickups and vans, along with specialized trucks using pickup and van chassis, as well as the larger "true" heavy-duty trucks, which typically have gross vehicle weight ratings of eight short tons or more. In the U.S., the large pickups and vans in this category greatly outnumber the heavier trucks, so that the emission factors calculated by MOBILE4 are more representative of these vehicles. This is also reflected in the fuel economy estimate for these vehicles of 6.1 miles/gal. The resulting emissions estimates are shown in Table D13-4.

Estimates were developed for three levels of emission control technology: uncontrolled, non-catalyst emission controls, and three-way catalyst technology. Non-catalyst emission controls include control of ignition timing and air-fuel ratio to minimize emissions, EGR, and air injection into the exhaust manifold to reduce HC and CO emissions. Three-way catalyst technology is presently used on heavy-duty gasoline vehicles in the U.S. It includes electronically-controlled fuel injection, EGR, air injection, and electronic control of ignition timing, as well as the catalyst itself.

Table D13-5: Estimated Emission Factors for Diesel Passenger Cars.

EMISSIONS					
	NO _x	CH ₄	NMVOC	CO	N ₂ O
Advanced Control					
Total - lbs/mile	0.0023	0.000035	0.0010	0.0031	0.000025
lbs/ton fuel	16.08	0.24	7.18	21.28	0.16
lbs/10 ⁶ Btu	0.420	0.007	0.186	0.552	0.004
Moderate Control					
Total - lbs/mile	0.0033	0.000035	0.0010	0.0031	0.000035
lbs/ton fuel	14.72	0.16	4.60	13.62	0.16
lbs/10 ⁶ Btu	0.376	0.004	0.119	0.354	0.004
Uncontrolled					
Total - lbs/mile	0.0036	0.000035	0.0018	0.0038	0.00005
lbs/ton fuel	12.10	0.12	6.18	12.58	0.16
lbs/10 ⁶ Btu	0.309	0.002	0.161	0.331	0.004

Light-duty diesel passenger cars. The U.S. EPA defines a diesel passenger car similarly to its gasoline counterpart, as a vehicle designed primarily to carry fewer than 12 passengers, and with manufacturer's rated gross vehicle weight less than 8,500 lb (3,855 kg), and not possessing special features such as four wheel drive for off-road operation. Table D13-5 summarizes the estimated emission factors for diesel passenger cars. Estimates are shown for three levels of emission control technology, ranging from uncontrolled, through moderate emissions control (achieved by changes in injection timing and combustion system design), through advanced emissions control utilizing modern electronic control of the fuel injection system, and exhaust gas recirculation.

Light-duty diesel trucks. Again, the U.S. EPA defines light-duty diesel trucks much like their gasoline counterparts, including gross vehicle weight, utility, and off-road operation features. Table D13-6 summarizes the estimated pollutant emissions for this vehicle class. The technology classifications are the same as those for diesel passenger cars.

Heavy-duty diesel vehicles. Although the EPA classification for heavy-duty diesel vehicles is the same as for gasoline vehicles, the characteristics of the vehicles themselves are rather different. Unlike heavy-duty gasoline vehicles, heavy-duty diesel vehicles are primarily large trucks, with gross vehicle weight ratings of 10 to 40 tons. Therefore, the MOBILE4 emission factors are more representative of large trucks (and buses) than the smaller pickup and van-type vehicles, and this is reflected in the fuel economy estimates. The resulting emission factors are summarized in Table D13-7. As with the other diesel categories, three levels of control are represented: uncontrolled, moderate control (typical of 1983 U.S.) and advanced control (for engines meeting U.S. 1991 emissions standards).

Motorcycles. Estimated emission factors for motorcycles are shown in Table D13-8. The MOBILE4 emission factors for these vehicles are based on the U.S. motorcycle population. The

Table D13-6: Estimated Emission Factors for Light-Duty Diesel Trucks.

EMISSIONS					
	NO _x	CH ₄	NMVOC	CO	N ₂ O
Advanced Control					
Total - lbs/mile	0.0027	0.000035	0.0015	0.0035	0.000032
lbs/ton fuel	13.54	0.18	7.48	17.46	0.16
lbs/10 ⁶ Btu	0.354	0.005	0.199	0.464	0.004
Moderate Control					
Total - lbs/mile	0.0037	0.000035	0.0015	0.0035	0.00005
lbs/ton fuel	12.34	0.12	4.98	11.64	0.16
lbs/10 ⁶ Btu	0.331	0.003	0.133	0.309	0.004
Uncontrolled					
Total - lbs/mile	0.0051	0.00007	0.0029	0.0057	0.00006
lbs/ton fuel	14.34	0.20	8.22	15.92	0.16
lbs/10 ⁶ Btu	0.376	0.000	0.221	0.420	0.004

Table D13-7: Estimated Emission Factors for Heavy-Duty Diesel Vehicles.

EMISSIONS					
	NO _x	CH ₄	NMVOC	CO	N ₂ O
Advanced Control					
Total - lbs/mile	0.0178	0.0002	0.0045	0.0241	0.00009
lbs/ton fuel	32.54	0.38	8.18	44.18	0.16
lbs/10 ⁶ Btu	0.840	0.011	0.221	1.149	0.004
Moderate Control					
Total - lbs/mile	0.0424	0.00025	0.0060	0.0294	0.00009
lbs/ton fuel	76.82	0.46	10.94	53.28	0.16
lbs/10 ⁶ Btu	1.989	0.022	0.287	1.392	0.004
Uncontrolled					
Total - lbs/mile	0.0596	0.00035	0.0106	0.0303	0.00011
lbs/ton fuel	85.72	0.52	15.26	43.60	0.16
lbs/10 ⁶ Btu	2.232	0.022	0.398	1.127	0.004

factors for uncontrolled motorcycles include a mixture of two-stroke and four-stroke engines, with the VOC emissions due primarily to the two-strokes, and the NO_x to the four-stroke engines. The factors for motorcycles with non-catalyst emission controls reflect four-stroke engines only, as U.S. emission control regulations have essentially eliminated two-stroke engines from the market.

Highway Vehicles - Alternative Fuels

Alternative motor vehicle fuels such as natural gas, LP gas, methanol, and ethanol are presently being used in a limited way, and are the subjects of a great deal of research and development effort aimed at increasing their usage in the future. These fuels are considered attractive for a number of reasons, including potentially lower pollutant emissions, reductions in emissions of gases contributing to global warming, and increased diversity of fuel supply. Since the number of vehicles using these fuels is relatively small, and they are, in many cases, still under development, little information is available on typical pollutant emission levels in service. MOBILE4

Table D13-8: Estimated Emission Factors for Motorcycles.

EMISSIONS					
	NO _x	CH ₄	NMVOC	CO	N ₂ O
Non-Catalytic Control					
Total - lbs/mile	0.0019	0.0005	0.0078	0.0468	0.000007
lbs/ton fuel	21.04	5.96	85.80	521.99	0.08
lbs/10 ⁶ Btu	0.530	0.155	2.143	13.038	0.002
Uncontrolled					
Total - lbs/mile	0.0007	0.0012	0.0231	0.0844	0.000007
lbs/ton fuel	6.46	11.20	222.00	809.99	0.08
lbs/10 ⁶ Btu	0.155	0.287	5.524	20.330	0.002

and other emissions models do not yet address alternative-fuel vehicles. This section presents some rough estimates of the emissions to be expected from vehicles using these fuels, based on fuel properties and the limited emissions data available. The reader is cautioned, however, that actual emission levels from these vehicles may be very different, and further testing would be needed to confirm these estimates.

Natural gas. Because natural gas is mostly methane, natural gas vehicles (NGVs) have lower exhaust NMVOC emissions than gasoline vehicles, but higher emissions of methane. Since the fuel system is sealed, there are no evaporative or running-loss emissions, and refueling emissions are negligible. Cold-start emissions from NGVs are also low, since cold-start enrichment is not required, and this reduces both NMVOC and CO emissions. NGVs are normally calibrated with somewhat leaner fuel-air ratios than gasoline vehicles, which also reduces CO emissions. Given equal energy efficiency, CO₂ emissions from NGVs will be lower than for gasoline vehicles, since natural gas has a lower carbon content per unit of energy. In addition, the high octane value for natural gas (Research Octane Number [RON] of 120 or more) makes it possible to attain increased efficiency by increasing the compression ratio. Optimized heavy-duty NGV engines can approach diesel efficiency levels. NO_x emissions from uncontrolled NGVs may be higher or lower than comparable gasoline vehicles, depending on the engine technology. Due to the low reactivity of the exhaust, NGV NO_x emissions are more difficult to control using three-way catalysts. Data on N₂O emissions from NGVs are not available, but probably resemble those for gasoline vehicles.

Table D13-9 shows very rough emissions estimates for three types of NGVs: passenger cars, gasoline-type heavy-duty vehicles, and diesel-type heavy-duty vehicles. Two sets of emission factors are shown for each: uncontrolled (typical of a simple natural gas conversion, without catalytic converter or optimization for emissions) and advanced control (reflecting an engine and catalytic converter factory-produced and optimized for natural gas). The estimates for the passenger car and gasoline-type heavy duty vehicle are based on a gasoline-type engine, converted to use natural gas. For the uncontrolled vehicles, no changes in the engine are assumed beyond the fitting of a natural gas mixer and modified spark timing such that the efficiency would be the same. For the vehicles with advanced control, a higher compression ratio is assumed to give 15 percent better fuel efficiency.

For the diesel-type heavy-duty vehicles, the engine assumed is a diesel-type engine, converted to lean, Otto-cycle operation using natural gas. The uncontrolled case reflects no further optimization beyond the conversion, while the controlled case includes extensive combustion optimization for NO_x control and an oxidation catalytic converter.

Table D13-9: Estimated Emission Factors for Light- and Heavy-Duty Natural Gas Vehicles.

EMISSIONS					
	NO _x	CH ₄	NMVOC	CO	N ₂ O
Passenger Car					
Advanced Control					
lbs/mile	0.0018	0.0025	0.00018	0.0011	N/A
lbs/ton fuel	20.60	29.00	2.00	12.40	N/A
lbs/10 ⁶ Btu	0.44	0.61	0.042	0.25	N/A
Uncontrolled					
lbs/mile	0.0075	0.0124	0.0018	0.0142	N/A
lbs/ton fuel	38.00	63.20	9.00	72.20	N/A
lbs/10 ⁶ Btu	0.80	1.32	0.19	1.51	N/A
Heavy-Duty Vehicles: Stoichiometric					
Advanced Control					
lbs/mile	0.0092	0.0106	0.0007	0.0035	N/A
lbs/ton fuel	26.00	30.00	2.00	10.00	N/A
lbs/10 ⁶ Btu	0.54	0.63	0.042	0.21	N/A
Uncontrolled					
lbs/mile	0.0202	0.0355	0.0050	0.0426	N/A
lbs/ton fuel	34.80	61.20	8.60	73.40	N/A
lbs/10 ⁶ Btu	0.73	1.28	0.19	1.53	N/A
Heavy-Duty Vehicles: Lean Burn Engine					
Advanced Control					
lbs/mile	0.0142	0.0142	0.0014	0.0053	N/A
lbs/ton fuel	26.60	26.60	2.60	10.00	N/A
lbs/10 ⁶ Btu	0.57	0.57	0.063	0.21	N/A
Uncontrolled					
lbs/mile	0.0816	0.0355	0.0071	0.0284	N/A
lbs/ton fuel	127.80	55.60	11.20	44.40	N/A
lbs/10 ⁶ Btu	2.68	1.17	0.23	0.92	N/A

In each case, the emissions considered are only those of the vehicle itself--additional emissions due to, e.g., compression or liquefaction of gas for storage on the vehicle, leakage from pipelines, etc. are not included, nor are the potential emissions credits due to, e.g., production of methane from biomass.

LPG gas. LPG has many of the same emissions characteristics as natural gas. The fact that it is primarily propane (or a propane/butane mixture) rather than methane affects the composition of exhaust VOC emissions, but otherwise the two fuels are similar. Evaporative and refueling emissions are nil, and CO and exhaust NMVOC emissions are usually lower than gasoline vehicles. CO₂ emissions should be somewhat lower than gasoline, due to the lower carbon-energy ratio, and the higher octane allows some increase in efficiency, although less than for natural gas. NO_x emissions from LPG vehicles tend to be higher than for gasoline, but can also be controlled using three-way catalysts. N₂O emissions data are not available, but should be similar to those for gasoline vehicles. Table D13-10 shows rough emissions estimates for four categories of LPG vehicles. The engines and technologies considered are the same as those for natural gas, except that the lean, diesel-derived natural gas engine with propane is not considered.

Table D13-10: Estimated Emission Factors for Light- and Heavy-Duty LP Gas Vehicles.

EMISSIONS					
	NO _x	CH ₄	NMVOC	CO	N ₂ O
Passenger Car					
Advanced Control					
lbs/mile	0.0018	0.00007	0.0009	0.0011	N/A
lbs/ton fuel	17.60	0.80	8.80	10.60	N/A
lbs/10 ⁶ Btu	0.420	0.022	0.221	0.243	N/A
Uncontrolled					
lbs/mile	0.0075	0.00064	0.0124	0.0284	N/A
lbs/ton fuel	35.40	3.00	59.00	135.00	N/A
lbs/10 ⁶ Btu	0.840	0.066	1.414	3.204	N/A
Heavy-Duty Vehicles: Stoichiometric					
Advanced Control					
lbs/mile	0.0092	0.00035	0.0025	0.0035	N/A
lbs/ton fuel	22.40	0.80	6.00	8.60	N/A
lbs/10 ⁶ Btu	0.530	0.022	0.155	0.199	N/A
Uncontrolled					
lbs/mile	0.0202	0.0014	0.0284	0.0851	N/A
lbs/ton fuel	33.60	2.40	47.00	141.20	N/A
lbs/10 ⁶ Btu	0.796	0.066	1.127	3.359	N/A

Methanol and ethanol. The two alcohols have similar properties, and will be discussed together. Pure alcohols are handicapped as fuels for Otto-cycle engines by their low vapor pressure, which makes cold starting difficult. For this reason, development efforts have focused primarily on mixtures of alcohols with gasoline. Flexible fuel vehicles, capable of running on any combination of gasoline and up to 85 percent methanol or ethanol have been developed, and a number of fleets of these vehicles are being demonstrated. The engines and emission control systems on these vehicles are similar to those for advanced-technology gasoline vehicles, and the overall energy efficiency and emissions properties are similar. Table D13-11 shows estimated emissions for a vehicle of this type using M85 (85% methanol/15% gasoline) fuel.

Heavy-duty engines can also be operated on methanol or ethanol, using a variety of technical approaches. Emissions data for heavy-duty engines on ethanol are not available, but a number of heavy-duty methanol engines have been developed. The most promising approach is to inject the methanol in liquid form, as in a diesel engine, so that engines using this approach can attain diesel-like efficiencies. Table D13-11 also shows some rough emissions estimates for heavy-duty vehicles equipped with such engines.

In each of the cases in Table D13-11, the estimates include only the emissions produced by the vehicle itself. The additional methane emissions associated with producing the methanol from natural gas are not included.

Electric Vehicles. No methodology is provided at this time for emissions from electric vehicles. Electric vehicles have received much attention because they do not generate emissions while in use; as a result, they may offer substantial benefits in urban areas with local air quality problems. They are not, however, "pollution free". Electric vehicles rely on electricity when the vehicles are not in

Table D13-11: Estimated Emission Factors for Light- and Heavy-Duty Methanol Vehicles.

EMISSIONS					
	NO _x	CH ₄	NMVOC	CO	N ₂ O
Passenger Car					
Advanced Control					
lbs/mile	0.0018	0.00007	0.0023	0.0111	N/A
lbs/ton fuel	9.00	0.40	11.80	56.00	N/A
lbs/10 ⁶ Btu	0.42	0.022	0.55	2.63	N/A
Heavy-Duty Vehicles: Methanol Diesel Engine					
Advanced Control					
lbs/mile	0.0142	0.00035	0.0053	0.0142	N/A
lbs/ton fuel	12.20	0.40	4.60	12.20	N/A
lbs/10 ⁶ Btu	0.66	0.022	0.24	0.66	N/A

use to recharge the batteries for continued operation. The electricity required for this activity could be generated from a number of fuels, including renewables, nuclear, natural gas, or coal. An in-depth examination of total fuel cycle emissions from the use of electric vehicles is beyond the scope of the current analysis. The reader is cautioned, however, from viewing electric vehicles as zero-emitters of greenhouse gases since, arguably, the emissions produced to provide the electricity for recharging are a direct result of fuel consumption by electric vehicles.

Non-Road Mobile Sources

Although mobile sources other than road vehicles account for a significant fraction of total mobile source emissions, they have received relatively little study compared to passenger cars and heavy-duty trucks. Major sources of pollutant emissions among non-road vehicles include farm and construction equipment, railway locomotives, boats, and ships (all primarily equipped with diesel engines), jet aircraft, and gasoline-fueled piston aircraft.

A recent study by Weaver (1988) for the U.S. EPA compiled the available (extremely scarce) data on emissions from diesel engines used in railway locomotives, farm equipment such as tractors and harvesters, construction equipment such as bulldozers and cranes, and diesel boats, and developed emission factors for each category. Fuel-specific emission factors calculated from Weaver (1988) are shown in Table D13-12. Since Weaver (1988) did not estimate N₂O emissions, and no other data for off-road diesels were available, we assumed that fuel-specific N₂O emissions would be similar to those for heavy-duty on-highway diesel engines.

Weaver (1988) did not estimate emission levels for large ocean-going ships, as opposed to boats used in coastal and inland traffic. Commercial cargo ships are driven primarily by large, slow-speed and medium-speed diesel engines. Other power sources that are occasionally found include steam turbines and gas turbines (the latter in high power-weight ratio vessels such as fast ferries and warships). The number of vessels equipped with steam or gas-turbine propulsion is small, however, since these vessels are unable to compete with the more efficient diesels in most applications.

A number of emissions measurements have recently become available for large marine diesel engines. Hadler (1990) reports data from which it can be calculated that a 9800 kW engine in a containership, operating at 85 percent power, produced 174 lbs of NO_x per ton of fuel burned. Melhus (1990), studying engines used in Norwegian coastal vessels, found NO_x emissions ranging from 86 to 150 lbs/ton fuel in four-stroke medium-speed engines, and from 100 to 166 lbs/ton fuel in

Table D13-12: Estimated Emission Factors for Non-Highway Mobile Sources.

UNCONTROLLED EMISSIONS					
	NO _x	CH ₄	NMVOC	CO	N ₂ O
OCEAN-GOING SHIPS					
lbs/ton fuel	174.0	n/a	n/a	3.80	0.16
lbs/10 ⁶ Btu	4.64	n/a	n/a	0.10	0.0044
BOATS					
lbs/ton fuel	135.0	0.46	9.80	42.60	0.16
lbs/10 ⁶ Btu	3.54	0.011	0.24	1.10	0.0044
LOCOMOTIVES					
lbs/ton fuel	148.6	0.50	11.00	52.20	0.16
lbs/10 ⁶ Btu	3.98	0.013	0.29	1.35	0.0044
FARM EQUIPMENT					
lbs/ton fuel	127.0	0.90	19.20	50.80	0.16
lbs/10 ⁶ Btu	3.31	0.024	0.51	1.33	0.0044
CONSTRUCTION & INDUSTRIAL EQUIPMENT					
lbs/ton fuel	100.4	0.36	7.80	32.60	0.16
lbs/10 ⁶ Btu	2.65	0.009	0.20	0.84	0.0044
JET & TURBOPROP AIRCRAFT					
lbs/ton fuel	25.0	0.17	1.56	10.40	n/a
lbs/10 ⁶ Btu	0.64	0.0044	0.04	0.27	n/a
GASOLINE (PISTON) AIRCRAFT					
lbs/ton fuel	7.04	5.28	48.00	2067.97	0.08
lbs/10 ⁶ Btu	0.18	0.133	1.19	53.03	0.002

(presumably slow-speed) two-stroke engines. Bremmes (1990) used an average value of 140 lbs/ton fuel, based on earlier measurements by Marintek. Alexandersson (1990) used NO_x emission factors of 0.04 lbs/kWH (188 lbs/ton fuel) for two-stroke and 0.03 lbs/kWH (144 lbs/ton fuel) for four-stroke marine diesel engines, both at 80 percent load. Although these measurements vary considerably among themselves, it is apparent that brake-specific and fuel-specific NO_x emissions from marine diesel engines are comparable to those from other uncontrolled diesel engines. For the results shown in Table D13-12, we used the data of Hadler (1990). NO_x emissions reported by this source appear representative of the range of emission values reported, and this was also the only data source reporting CO as well as NO_x data. None of the data sources available reported VOC or N₂O data. For lack of better data, fuel-specific N₂O emissions for these engines were assumed to be the same as those for other heavy-duty diesels. VOC emissions from these large diesels are probably negligible.

Pollutant emissions from aircraft are another area that has received relatively little attention. While emission factors have been developed for most commercial aircraft types (EPA, 1985), these are expressed in terms of emissions per landing and take-off cycle (LTO)--an inconvenient unit for cross comparison. Another problem with these factors is that they include only emissions in the immediate vicinity of the airport, *i.e.*, emissions under cruise conditions are not included. Since most aircraft operate primarily in cruise, this is a serious concern.

Data on cruise emissions from aircraft are being developed by the U.S. Federal Aviation Administration, but are not available at this time. The factors for jet (turbine) aircraft shown in Table D13-12 were developed by Radian (1990) based on emissions from a Pratt and Whitney JT-17

engine, one of the most commonly used types. These factors are repeated here for lack of better data. The emission factors for small gasoline-fueled piston aircraft were also developed by Radian (1990) based on a Cessna engine. These are also considered very approximate. Additional research will be necessary to resolve the problems associated with limited data on cruise emissions.

No data on N₂O emissions from aircraft turbine engines were available. For the gasoline piston engines, fuel-specific N₂O emissions were assumed to be similar to those for uncontrolled passenger cars.

DATA SOURCES

The emission factors in Tables D13-2 through D13-12 can only be used if energy consumption can be adequately characterized by the fuel and technology types contained in these tables. For example, for transportation needs, information is required on the percentage of light-duty versus heavy-duty vehicles by fuel type (gasoline- versus diesel-fueled) and the extent of emission controls for each category. There is no single data source that comprehensively provides all relevant information. There are several sources, however, that can help to determine this information.

For example, activity data on vehicle fleet characteristics will be needed. The main sources of data available on transport are U.S. EPA, U.S. Department of Transportation (U.S. DOT), and U.S. DOE. State Departments of Motor Vehicles or other state agencies may also be useful data sources. As discussed earlier, the most reliable source for energy statistics is probably the U.S. Department of Energy (DOE), where data on transport activities are detailed by fuel type and basic transport mode. These data are available for most mobile source energy consumption in the U.S.. Similarly, the most reliable source for basic transportation statistics, such as vehicle miles traveled and airline flight statistics, would be the Federal Highway Administration and the Federal Aviation Administration respectively, both of which are part of U.S. DOT.

MOBILE4

Emission factors for certain greenhouse gas emissions from road vehicles can be developed using the MOBILE4 computer model.¹ This model was the basis for most of the emission factors presented in Tables D13-2 to D13-12, and can be used to calculate average emission rates for any selected calendar year (from 1960 to 2020) essentially by aging the fleet and weighting the emission factors by the shares of distance travelled by vehicles of various ages. The emission factors are estimated as a function of several parameters, including

- vehicle type,
- model year (technology),
- vehicle age and accumulated mileage,
- percent of driving in cold start, hot start or stabilized conditions,
- average speed,
- ambient temperatures,
- fuel volatility, and
- tampering rates with emission control systems.

Since these variables can be manipulated by the user, the conditions can be altered to reflect conditions in a variety of geographic regions and regulatory situations.

MOBILE4 calculates emission factors for total and non-methane hydrocarbons (HC and NMHC, the difference between these two values indirectly determines the methane factors), NO_x and CO for the four vehicle types mentioned above (LDV, LDT, HDT, 2W) and two fuels (gasoline and diesel). The emissions performance in MOBILE4 for vehicles under various conditions is estimated based on years of extensive testing of vehicles in use in the United States. The user can specify input data for the particular region or country, and emission factors that are tailored to that particular region will be estimated.

Several notes of caution need to be given on the use of MOBILE4 for development of GHG emission factors. First, the pollutant coverage is incomplete (including only NO_x, CO, VOC, and NMVOCs with methane as a calculated result of the difference between NMVOC and VOC). N₂O from vehicles is, however, believed to be relatively insignificant. Finally, it is believed that this method of "difference" calculation may significantly underestimate methane from vehicles. Since the methane emission factor may be erroneous, it should be cross-checked with available literature on the subject.

Second, alternative fuel vehicles are not yet incorporated into the model. Supplementary information must therefore be used to develop these factors should the fuel mix in transport activities require them. Any assumptions used to build these factors should be as comparable as possible with those for conventional motor fuels.

¹ The MOBILE4 Model and its *User's Guide* can be obtained from:

The U.S. National Technical Information Service, U.S. Department of Commerce
Springfield, Virginia 22161

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DISCUSSION 14

OTHER GREENHOUSE GAS EMISSIONS FROM STATIONARY COMBUSTION

OVERVIEW

This section discusses non-CO₂ greenhouse gas emissions (*i.e.*, NO_x, N₂O, CO, CH₄, and NMVOCs) from energy consumption in stationary sources. The reader should note before proceeding with this section that these calculations can be time consuming and complex. Moreover, the amount of gases emitted from these activities are not thought to be major contributors to climate change. Additionally, data on gases such as CO, NO_x, and NMVOCs may already be collected by state environmental or air quality agencies to determine state compliance with the *Clean Air Act* or other regulations. For these reasons a methodology for this source category was not included in the workbook.

Emissions of non-CO₂ greenhouse gases across activities (sectors) will depend upon fuel, technology type, and pollution control policies. Emissions will also vary more specifically with size and vintage of the combustion technology, its maintenance, and its operation.

Electricity generation and industrial fuel combustion activities are similar in that they provide combustion conditions conducive to NO_x formation. NO_x emissions depend in part on the nitrogen contained in the fuel (this may be especially important for coal), but more importantly on the firing configuration of the technology. Excess air and high temperatures contribute to high NO_x emissions. Such conditions are highly variable by type of boiler; for instance, for oil-fired plants, tangential burner configurations generally have lower emission coefficients than horizontally opposed units. Also, the size of the boiler will affect the NO_x emission rate due to the lower temperatures of smaller units.

The level of equipment use can also significantly alter the pattern of NO_x emissions. Measurements of emissions show a 0.5 percent to 1.0 percent decrease in NO_x emission rates for every 1.0 percent decrease in load from full load operation. That is, as the usage rate increases, so does the emission rate associated with the facility.

Finally, control policies and related technological changes to meet emission limits directly influence NO_x emissions. Emissions from large facilities can be reduced by up to 60 percent by straightforward adjustments to the burner technology.¹ These adjustments are often standard in new facilities, but may not exist in older facilities. NO_x controls may also increase the rate of CO emissions. Information on the stock of combustion facilities, their vintage, and level of control are therefore necessary to accurately estimate emissions from large combustion facilities.

NO_x emissions from small combustion facilities (small industry, commercial, and residential) tend to be much less significant than for large facilities as a result of lower combustion temperatures.

¹ This can be done, for example, by limiting the excess air in combustion or by staging the combustion process.

Nevertheless, emissions will depend on the specific combustion conditions of the activity in question, and an effort should be made to carefully characterize the type of activity, on average, in order to select appropriate emission factors.

Combustion conditions in large facilities are less conducive to formation and release of CO and VOCs (methane included) than to NO_x. VOCs and CO are unburnt gaseous combustibles that are emitted in small quantities due to incomplete combustion. They have also been the target of emission control policies and hence must be estimated with these controls in mind. They are directly influenced by usage patterns, technology type and size, vintage, maintenance, and operation of the technology. Emissions can vary by several orders of magnitude, for example, for facilities that are improperly maintained or poorly operated, such as may be the case for many older units. Similarly, during periods of start-up, combustion efficiency is lowest, and CO and VOC emissions are higher than during periods of full operation.

Size of the unit may indicate that combustion is less controlled and, hence, the VOC and CO emission coefficients for smaller units are likely to be higher than for large plants. Also, wood stoves, due to their largely inefficient combustion of the fuel, have particularly high emission rates of CO and VOCs. For these reasons, an understanding of commercial and residential activities are key to the estimation of these greenhouse gases.

N₂O is also produced from the combustion of fuels and the mechanisms of its formation are fairly well understood, although its importance is presently considered to be minor relative to other source categories. Quantitative estimation of N₂O emissions is currently sketchy, as earlier data were affected by a sampling artifact which resulted in erroneously high emission factors. This is discussed in more detail later, but in general, the data indicate that N₂O emissions may be technology dependent and thus will vary somewhat across sectors, applications, and fuel types.

DESCRIPTION OF METHOD

General Method

Estimation of emissions from stationary sources can be described using the following basic formula, which shows that total emissions for a particular state is the sum across activities, technologies, and fuel types.

$$\text{Emissions} = \sum (\text{EF}_{abc} \times \text{Activity}_{abc} \times (1-\text{R}_{abc}/100))$$

where:

EF = Emission Factor (lbs/10⁶ Btu);

Activity = Energy Input (10⁶ Btu);

R_{abc} = Percent reduction in emissions due to controls;

a = Fuel type;

b = Sector-activity; and

c = Technology type.

As seen in this equation, emission estimation is generally based on three sets of data, each of which vary by fuel type, sector, and technology: 1) energy activities; 2) emissions factors; and 3) control technologies. Sources of the emission factors and energy activities data that are relevant are described briefly below and suggestions on appropriate use of such data are made.

Given the general form of emissions calculations noted above, the main steps in the inventory method can be summarized as follows:

- Step 1:** Determine the best available state energy activity data, with consideration given to the compatibility and verifiability of each source.
- Step 2:** Determine the main categories of emission factors; based on a survey of state energy activities.
- Step 3:** Compile best available emission factor data for the state.
- Step 4:** Develop assumptions regarding the technology splits within the state, based on the form of the selected emission factor data².
- Step 5:** Develop estimates, main activity by main activity, of each of the greenhouse gases.
- Step 6:** Sum the individual activity estimates to arrive at the state inventory total for the greenhouse gases.

Energy Activity Data

Stationary sources have been divided into five sectors in EIA data sources: industry, agriculture, commercial, residential, and electric utilities.³ Each of these sectors uses energy through a variety of fuel combustion modes. For example, there are a number of technology and fuel options for heating a household, and emissions will vary according to these options. Sectoral data therefore provides a useful starting point for emission inventories, but will need to be further specified by the share of key technologies represented in each sector.

The basic sector/fuel categories for reporting purposes in Table D14-1 are based on EIA's *State Energy Data Report*. States are encouraged to provide the most detailed information available. DOE or EIA data could be used as a starting point, but states should use the energy data thought to be the most reliable. If states use in-state sources rather than EIA data, they are strongly urged to provide thorough documentation on the energy statistics, reporting procedures, and definitions of sectoral activities, and to aggregate their inventories to the categories in Table D14-1 for comparison purposes. This would help to ensure consistency and comparability among all state estimates.

Emission Factors and Control Technologies: General Data Sources

Preferably, emission factors should be drawn from state sources or detailed national sources (e.g., U.S. EPA data). If no state source is available, select from the options provided here. Selection

² This may require assumptions about the pollution control technologies in place.

³ Transportation is another sector frequently encountered in energy consumption statistics, but is not a stationary source. Other greenhouse gas emissions from transportation are addressed as mobile source emissions (see Discussion Section 13).

among the options should be based on an assessment of the similarity of the state to the source of original measurements for types of technology and operating conditions across main energy activities. The selection should also consider the extent to which control technologies may be in place and the ability to clearly separate and understand control policy assumptions that may be embedded in the emission factor data.

Table D14-1. Basic Sector/Fuel Categories

<u>FUELS</u>	<u>SECTORS</u>
<p>1. OIL</p> <p>Asphalt and Road Oil Aviation Gas Distillate Fuel Kerosene LPG Lubricants Motor Gasoline Residual Fuel Other Liquid Fuels</p>	<p>1. ELECTRIC UTILITIES</p> <p>2. INDUSTRY</p> <p>Iron and Steel Chemical Paper, Pulp, and Print Petroleum Refining Food and Tobacco Other Industry</p>
<p>2. COAL AND OTHER SOLIDS</p> <p>Bituminous Coal and Lignite Anthracite Other Solid Fuels</p>	<p>3. COMMERCIAL</p> <p>4. RESIDENTIAL</p>
<p>3. NATURAL GAS</p>	<p>5. OTHER</p>

Emission levels are affected by the specific technology used in the combustion process. The emissions factors discussed here generally represent the average emission performance of a population of similar combustion technologies. Emission factors for non-CO₂ greenhouse gases from combustion activities also vary, to lesser or greater degrees, with fuel type, equipment vintage, operating conditions, maintenance practices, and the use of control technologies. Therefore, good emission factors for gases other than CO₂ are technology specific, but may still represent a wide distribution of possible values. When available, the standard deviation of the emission factor should be used to show the range of possible emissions factors, and hence emissions, for each particular energy activity.⁴

⁴ Unfortunately, the standard deviation of emission factors is rarely reported with emission factor data. Eggleston and McInnes (1987) have shown that variation of the final estimates by energy activity range from 20 percent to more than 50 percent.

Representative emission factors for NO_x ⁵, CO, CH_4 , N_2O , and NMVOCs by main technology and fuel types are outlined in Tables D14-2 to D14-6 for the major sectoral categories.⁶ These data are taken from Radian (1990) and show uncontrolled emission factors for each of the technologies indicated. These emission factor data do not consider control technologies that might be in place in some states. Therefore, in places where control policies may significantly influence the emission profile, estimates will need to be adjusted by an emissions reduction factor as presented in the equation on page D14-2.

Alternative control technologies, with representative percentage reductions, are shown in Tables D14-7 to D14-10 (Radian, 1990) for the main control technologies applicable to each sector. The total emission estimate should be adjusted downward according to the indicated percentage reduction. Table D14-11 provides the fuel property assumptions upon which the Radian data are based.

The Radian data cited above reflect the performance range of main combustion technologies in place in the U.S. with a few exceptions. Since most of the data are based on measurement samples taken from the United States, they represent averages of operating conditions, sizes and vintages of units found in the U.S. Some emissions factors may be available from the U.S. EPA's *Compilation of Air Pollutant Emission Factors, AP-42* (U.S. EPA, 1985) and the overall control efficiency of a source category may be derived from U.S. EPA's Aerometric Information Retrieval System (AIRS) database.

Gas Specific Emissions Discussion

Nitrogen Oxides, Carbon Monoxide, and Non-Methane Volatile Organics (NO_x , CO, and NMVOCs)

For many years, NO_x has been the target of environmental policies for its role in forming ozone (O_3), as well as for its direct acidification effects. As a result, NO_x emission inventories and related data such as emission factors are more widely available than those for the other non- CO_2 greenhouse gases considered here, so state specific emission factor sources should be sought out.

CO emissions from stationary sources are estimated in the same way as for NO_x emissions. CO is an unburnt gaseous combustible that is emitted in small quantities due to incomplete combustion, and emission coefficients are often higher for small operations with less combustion control. Additionally, there may be significant variation in the precise size and type of combustion technologies in place. With this in mind, a main combustion source of CO is the residential sector, where the variation in technology, and hence emissions, is intensified by the small nature of the combustion sources and a wide variety of equipment manufacturers.

NMVOCs should also be included in the emissions inventory. At this time, however, no emission data are readily available in a consistent and comprehensive form from which to reliably estimate NMVOCs. Additional sources for emission factor data should be consulted if available. As

⁵ As a general rule, it is recommended that NO_x emissions be converted to a full molecular basis by assuming that all NO_x emissions are emitted as NO_2 .

⁶ Little information on N_2O and NMVOCs emission factors is included at this time for reasons discussed below (some N_2O factors thought to be reliable are included). These factors should be added as the data become available.

with N_2O , additional research is needed to improve the emissions factor data from which emissions inventories can be developed.

Methane (CH_4)

At this time no emission data other than the Radian data have been identified in a consistent and comprehensive form from which to reliably estimate CH_4 at the national level. State level sources may be available and should be used if deemed reliable and well documented. In the event that no detailed emission factor data can be found, but emission factor data for NMVOCs is located, estimates can be based on the rough percentage of methane emissions relative to NMVOC emissions. In this case, some default ratios of CH_4 emissions to NMVOCs are provided in Table D14-12. It should be noted that this method gives very imprecise estimates and should only be used as a last resort.

Nitrous Oxide (N_2O)

N_2O is produced from the combustion of fossil fuels, and the mechanisms that cause N_2O formation are fairly well understood. There has been considerable difficulty, however, in determining emission factors, because procedures formerly used to measure N_2O emissions were found to suffer from a sampling artifact whereby N_2O formed in the sample containers as a result of reactions between water, sulfur dioxide, and NO_x . This "sampling artifact," which generally affected samples taken prior to July 1988, resulted in erroneous emission factors which were much too high. Since recognition of the artifact in June 1988, new measurements have led to more reliable emission factors for some conventional combustion sources (De Soete, 1993 as cited in IPCC, 1994). Fuel specific (but not necessarily application-specific) emission factors are now available for commercial combustion. Data further indicate that N_2O emissions may be technology dependent, particularly with respect to reaction temperatures⁷.

Table D14-13 contains general N_2O emission factors and preliminary uncertainty ranges by major fuel type. These factors are not technology or sector specific and do not include emission controls. They can be used as default values in the event that no technology and sector specific factors are provided in Tables D14-2 through D14-6. Emission control performance will need to be factored in if they are present in the state. If other data are used, care should be taken that no "artifact data" (as described above) were used in deriving the factors.

⁷For low and high combustion temperatures (much less than 1000K and much greater than 1200K) N_2O emissions are likely negligible, while the highest emission levels are between 800K and 1100K (maximum around 1000K). Additionally, increasing pressure and oxygen concentration increase N_2O emissions (IPCC, 1994).

Table D14-2. Utility Boiler Source Performance

Source	Emissions Factors (lbs/10 ⁶ Btu energy input)				
	CO	CH ₄	NO _x	N ₂ O	NMVOCs
Natural Gas - Boilers	0.040	0.0002	0.559	N/A	N/A
Gas Turbine Combined Cycle	0.067	0.0128	0.391	N/A	N/A
Gas Turbine Simple Cycle	0.067	0.0124	0.394	N/A	N/A
Residual Oil Boilers	0.033	0.0015	0.444	N/A	N/A
Distillate Oil Boilers	0.033	0.00007	0.150	N/A	N/A
Shale Oil Boilers	0.033	0.0015	0.444	N/A	N/A
MSW - Mass Feed	0.217	N/A	0.309	N/A	N/A
Coal - Spreader Stoker	0.267	0.0015	0.720	0.0018	N/A
Coal - Fluidized Bed Combined Cycle	N/A	0.0013	N/A	N/A	N/A
Coal - Fluidized Bed	N/A	0.0013	0.563	N/A	N/A
Coal - Pulverized Coal	0.031	0.0013	1.894	0.0018	N/A
Coal - Tangentially Fired	0.031	0.0013	0.729	0.0018	N/A
Coal - Pulverized Coal Wall Fired	0.031	0.0013	1.019	0.0018	N/A
Wood-Fired Boilers	3.255	0.0398	0.247	N/A	N/A

Source: Radian, 1990.

Table D14-3. Industrial Boiler Performance

Source	Emissions Factors (lbs/10 ⁶ Btu energy input)				
	CO	CH ₄	NO _x	N ₂ O	NMVOCs
Coal-Fired Boilers	0.206	0.0053	0.73	N/A	N/A
Residual Oil-Fired Boilers	0.033	0.0064	0.36	N/A	N/A
Natural Gas-Fired Boilers	0.036	0.0029	0.14	N/A	N/A
Wood-Fired Boilers	3.32	0.0331	0.25	N/A	N/A
Bagasse/Agri. Waste-Fired Boilers	3.77	N/A	0.19	N/A	N/A
MSW - Mass burn	0.212	N/A	0.31	N/A	N/A
MSW - Small Modular	0.042	N/A	0.31	N/A	N/A

Source: Radian, 1990.

Table D14-4. Kilns, Ovens, and Dryers Source Performance

Industry	Source	Emissions Factors (lbs/10 ⁶ Btu energy input)				
		CO	CH ₄	NO _x	N ₂ O	NMVOCs
Cement, Lime	Kilns - Natural Gas	0.174	0.0023	2.33	N/A	N/A
Cement, Lime	Kilns - Oil	0.175	0.0022	1.16	N/A	N/A
Cement, Lime	Kilns - Coal	0.175	0.0022	1.16	N/A	N/A
Coking, Steel	Coke Oven	0.466	0.0022	N/A	N/A	N/A
Chemical Processes, Wood, Asphalt Copper, Phosphate	Dryer - Natural Gas	0.023	0.0023	0.13	N/A	N/A
Chemical Processes, Wood, Asphalt Copper, Phosphate	Dryer - Oil	0.035	0.0022	0.37	N/A	N/A
Chemical Processes, Wood, Asphalt Copper, Phosphate	Dryer - Coal	0.396	0.0022	0.50	N/A	N/A

Source: Radian, 1990.

Table D14-5 Residential Source Performance

Source	Emissions Factors (lbs/10 ⁶ Btu energy input)				
	CO	CH ₄	NO _x	N ₂ O	NMVOCs
Wood Pits	10.94	0.442	0.325	N/A	N/A
Wood Fireplaces	13.26	N/A	0.256	N/A	N/A
Wood Stoves	40.95	0.164	0.442	N/A	N/A
Propane/Butane Furnaces	0.022	0.0024	0.104	N/A	N/A
Coal Hot Water Heaters	0.040	N/A	0.349	N/A	N/A
Coal Furnaces	1.070	N/A	0.513	N/A	N/A
Coal Stoves	7.911	N/A	0.396	N/A	N/A
Distillate Oil Furnaces	0.029	0.0110	0.113	N/A	N/A
Gas Heaters	0.021	0.0021	0.098	N/A	N/A

Source: Radian, 1990.

Table D14-6. Commercial Source Performance

Source	Emissions Factors (lbs/10 ⁶ Btu input)				
	CO	CH ₄	NO _x	N ₂ O	NMVOCs
Wood Boilers	0.440	0.0331	0.073	0.0095	N/A
Gas Boilers	0.020	0.0025	0.100	0.0050	N/A
Residual Oil Boilers	0.038	0.0035	0.343	0.103	N/A
Distillate Oil Boilers	0.035	0.0013	0.141	0.035	N/A
MSW Boilers	0.042	N/A	1.023	N/A	N/A
Coal Boilers	0.431	0.0221	0.522	0.131	N/A
Shale Oil Boilers	0.038	0.0035	0.411	0.103	N/A
Open Burning - MSW ¹	92.8	14.4	6.6	N/A	N/A
Open Burning - Agriculture ¹	128.2	19.9	N/A	N/A	N/A
Incineration - high efficiency ¹	11.0	N/A	3.3	N/A	N/A
Incineration - low efficiency ¹	22.1	N/A	2.2	N/A	N/A

¹ Emission factors are presented in lbs/billion Btu

Source: Radian, 1990.

Table D14-7. Utility Emission Controls Performance

Technology	Efficiency Loss ¹ (%)	CO Reduction (%)	CH ₄ Reduction (%)	NO _x Reduction (%)	N ₂ O Reduction (%)	NMVOCs Reduction (%)	Date Available ²
Low Excess Air	-0.5	+	+	15	N/A	N/A	1970
Overfire Air - Coal	0.5	+	+	25	N/A	N/A	1970
Overfire Air - Gas	1.25	+	+	40	N/A	N/A	1970
Overfire Air - Oil	0.5	+	+	30	N/A	N/A	1970
Low NO _x Burner - Coal	0.25	+	+	35	N/A	N/A	1980
Low NO _x Burner - TF	0.25	+	+	35	N/A	N/A	1980
Low NO _x Burner - Oil	0.25	+	+	35	N/A	N/A	1980
Low NO _x Burner - Gas	0.25	+	+	50	N/A	N/A	1980
Cyclone Combustion Modification	0.5	N/A	N/A	40	N/A	N/A	1990
Ammonia Injection	0.5	+	+	60	N/A	N/A	1985
SCR - Coal	1	8	+	80	N/A	N/A	1985
SCR - Oil, AFBC	1	8	+	80	N/A	N/A	1985
SCR - Gas	1	8	+	80	60	N/A	1985
Water Injection - Gas Turbine Simple Cycle	1	+	+	70	N/A	N/A	1975
SCR - Gas Turbine	1	8	+	80	60	N/A	1985
CO ₂ Scrubbing - Coal	22.5	N/A	N/A	N/A	N/A	N/A	2000
CO ₂ Scrubbing - Oil	16.0	N/A	N/A	N/A	N/A	N/A	2000
CO ₂ Scrubbing - Gas	11.3	N/A	N/A	N/A	N/A	N/A	2000
Retrofit LEA	-0.5	+	+	15	N/A	N/A	1970
Retrofit OFA - Coal	0.5	+	+	25	N/A	N/A	1970
Retrofit OFA - Gas	1.25	+	+	40	N/A	N/A	1970
Retrofit OFA - Oil	0.5	+	+	30	N/A	N/A	1970
Retrofit LNB - Coal	0.25	+	+	35	N/A	N/A	1980
Retrofit LNB - Oil	0.25	+	+	35	N/A	N/A	1980
Retrofit LNB - Gas	0.25	+	+	50	N/A	N/A	1980
Burners Out of Service (BOOS)	0.5	+	+	30	N/A	N/A	1975

¹ Efficiency loss is percent of end-user energy conversion efficiency. Negative loss indicates an efficiency improvement.

² Date technology is assumed to be commercially available.

Note: A "+" indicates negligible reduction.

Source: Radian, 1990.

Table D14-8. Industrial Boiler Emission Controls Performance

Technology	Efficiency Loss ¹ (%)	CO Reduction (%)	CH ₄ Reduction (%)	NO _x Reduction (%)	N ₂ O Reduction (%)	NMVOCs Reduction (%)	Date Available ²
Low Excess Air	-0.5	+	+	15	N/A	N/A	1970
Overfire Air - Coal	0.5	+	+	25	N/A	N/A	1970
Overfire Air - Gas	1.25	+	+	40	N/A	N/A	1970
Overfire Air - Oil	0.5	+	+	30	N/A	N/A	1970
Low NO _x Burner - Coal	0.25	+	+	35	N/A	N/A	1980
Low NO _x Burner - Oil	0.25	+	+	35	N/A	N/A	1980
Low NO _x Burner - Gas	0.25	+	+	50	N/A	N/A	1980
Flue Gas Recirculation	0.5	+	+	40	N/A	N/A	1975
Ammonia Injection	0.5	+	+	60	N/A	N/A	1985
SCR - Coal	1	8	+	80	N/A	N/A	1985
SCR - Oil, AFBC	1	8	+	80	N/A	N/A	1985
SCR - Gas	1	8	+	80	60	N/A	1985
Retrofit LEA	-0.5	+	+	15	N/A	N/A	1970
Retrofit OFA - Coal	0.5	+	+	25	N/A	N/A	1970
Retrofit OFA - Gas	1.25	+	+	40	N/A	N/A	1970
Retrofit OFA - Oil	0.5	+	+	30	N/A	N/A	1970
Retrofit LNB - Coal	0.25	+	+	35	N/A	N/A	1980
Retrofit LNB - Oil	0.25	+	+	35	N/A	N/A	1980
Retrofit LNB - Gas	0.25	+	+	50	N/A	N/A	1980

¹Efficiency loss as a percent of end-user energy conversion efficiency. Negative loss indicates an efficiency improvement.

²Date technology is assumed to be commercially available.

Note: A "+" indicates negligible reduction.

Source: Radian, 1990.

Table D14-9. Kiln, Ovens, and Dryers Emission Controls Performance

Technology	Efficiency Loss ¹ (%)	CO Reduction (%)	CH ₄ Reduction (%)	NO _x Reduction (%)	N ₂ O Reduction (%)	NMVOCs Reduction (%)	Date Available ²
LEA - Kilns, Dryers	-6.4	+	+	14	N/A	N/A	1980
LNB - Kilns, Dryers	0	+	+	35	N/A	N/A	1985
SCR - Coke Oven	1.0	8	+	80	60	N/A	1979
Nitrogen Injection	N/A	N/A	N/A	30	N/A	N/A	1990
Fuel Staging	N/A	N/A	N/A	50	N/A	N/A	1995

¹Efficiency loss as a percent of end-user energy conversion efficiency. Negative loss indicates an efficiency improvement.

²Date technology is assumed to be commercially available.

Note: A "+" indicates negligible reduction.

Source: Radian, 1990.

Table D14-10. Residential and Commercial Emission Controls Performance

Technology	Efficiency Loss ¹ (%)	CO Reduction (%)	CH ₄ Reduction (%)	NO _x Reduction (%)	N ₂ O Reduction (%)	NMVOCs Reduction (%)	Date Available ²
Catalytic Woodstove	-44	90	90	-27	N/A	N/A	1985
Non-Catalytic MCS	-30	15	50	-5	N/A	N/A	1985
Flame Ret. Burn. Hd.	-9	28	N/A	N/A	N/A	N/A	
Contr. Mix. Burn. Hd.	-7	43	N/A	44	N/A	N/A	
Integr. Furn. Syst.	-12	13	N/A	69	N/A	N/A	
Blueray Burn./Furn.	-12	74	N/A	84	N/A	N/A	
M.A.N. Burner	-13	N/A	N/A	71	N/A	N/A	1980
Radiant Screens	-7	62	N/A	55	N/A	N/A	
Secondary Air Baffle	N/A	16	N/A	40	N/A	N/A	
Surface Comb. Burner	N/A	55	N/A	79	N/A	N/A	
Amana HTM	-21	-55	N/A	79	N/A	N/A	
Modulating Furnace	-7	N/A	N/A	32	N/A	N/A	
Pulse Combuster	-36	N/A	N/A	47	N/A	N/A	
Catalytic Combuster	-29	N/A	N/A	86	N/A	N/A	
Replace Worn Units	N/A	65	N/A	N/A	N/A	N/A	
Tuning, Seasonal Maintenance	-2	16	N/A	N/A	N/A	N/A	
Red. Excess. Firing	-19	14	N/A	N/A	N/A	N/A	
Red fir with new ret b	-40	14	N/A	N/A	N/A	N/A	
Pos. Chimney Dampers	-8	11	N/A	N/A	N/A	N/A	
Inc. thermal anticip.	-1	43	N/A	N/A	N/A	N/A	
Night therm. cutback	-15	17	N/A	N/A	N/A	N/A	
Low Excess Air	-0.8	N/A	N/A	15	N/A	N/A	1970
Flue Gas Recirculation	0.6	N/A	N/A	50	N/A	N/A	1975
Over-fire Air	1	N/A	N/A	20	N/A	N/A	1970
Over-fire Air	1	N/A	N/A	30	N/A	N/A	1970
Low NO _x Burners	0.6	N/A	N/A	40	N/A	N/A	1980
Low NO _x Burners	0.6	N/A	N/A	50	N/A	N/A	1980

¹Efficiency loss as a percent of end-user energy conversion efficiency. Negative loss indicates an efficiency improvement.

²Date technology is assumed to be commercially available.

Note: A "+" indicates negligible reduction.

Source: Radian, 1990.

Table D14-11. Fuel Properties

Fuel	Heating Value (10^6 Btu/ton) ¹	Carbon (wt percent)
Butane/Propane	43.7	82.0
Coke Oven Gas	35.1	56.1
Methane (pure)	43.0	75.0
Natural Gas	43.9	70.6
Process Gas	46.4	70.6
LIQUID		
Crude Shale Oil	37.0	84.5
Diesel/Distillate	38.8	87.2
Gasoline	111×10^3 Btu/gal	85.7
Jet A	37.1	86.1
Methanol	53×10^3 Btu/gal	37.5
Residual Oil	37.0	85.6
SOLID		
Bagasse/Agriculture	7.8	22.6
Charcoal	25.0	87.0
Coal	19.9	65.0
MSW	9.7	26.7
Wood	9.1	27.0

¹ Unless otherwise indicated.

Source: Radian, 1990.

Table D14-12. Ratio of CH₄ to NMVOCs Released During Combustion

Activity	Ratio of CH ₄ to NMVOC Emissions (Low to High)
Coal Combustion	0.05 to 1.00
Fuel Oil Combustion	0.05 to 0.10
Wood Combustion (Industrial Use)	0.2
Wood Combustion (Residential Use),	2
Other	0.1

Source: U.S. EPA, 1993; except "Other," where the upper end of the fuel oil category was used as an approximation..

Table D14-13. N₂O Emissions Factors for Conventional Facilities by Fuel Type

Fuel	Emission Factor (lbs/10 ⁶ Btu)	Uncertainty Range
Coal	0.0032	0 - 0.0234
Oil	0.0014	0 - 0.0065
Gas	0.0002	0 - 0.0026

Source: De Soette (1993) as cited in IPCC (1994)

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PART III

APPENDICES

GLOSSARY¹

Aerosol: Particulate material, other than water or ice, in the atmosphere. Aerosols are important in the atmosphere as nuclei for the condensation of water droplets and ice crystals, as participants in various chemical cycles, and as absorbers and scatterers of solar radiation, thereby influencing the radiation budget of the earth-atmosphere system, which in turn influences the climate on the surface of the Earth.

Afforestation: The process of establishing a forest, especially on land not previously forested.

Anaerobic Fermentation: Fermentation that occurs under conditions where oxygen is not present. For example, methane emissions from landfills result from anaerobic fermentation of the landfilled waste.

Anthropogenic: Of, relating to, or resulting from the influence of human beings on nature.

Atmosphere: The envelope of air surrounding the Earth and bound to it by the Earth's gravitational attraction.

Biomass: The total dry organic matter or stored energy content of living organisms that is present at a specific time in a defined unit (ecosystem, crop, etc.) of the Earth's surface.

Biosphere: The portion of Earth and its atmosphere that can support life.

Carbon Sink: A pool (reservoir) that absorbs or takes up released carbon from another part of the carbon cycle. For example, if the net exchange between the biosphere and the atmosphere is toward the atmosphere, the biosphere is the source, and the atmosphere is the sink.

Carbon Dioxide (CO₂): Carbon dioxide is an abundant greenhouse gas, accounting for about 66 percent of the total contribution in 1990 of all greenhouse gases to radiative forcing. Atmospheric concentrations have risen 25% since the beginning of the Industrial Revolution. Anthropogenic source of carbon dioxide emissions include combustion of solid, liquid, and gases fuels, (e.g., coal, oil, and natural gas, respectively), deforestation, and non-energy production processes such as cement-production.

Carbon Monoxide (CO): Carbon monoxide is an odorless, invisible gas created when carbon-containing fuels are burned incompletely. Participating in various chemical reactions in the atmosphere, CO contributes to smog formation, acid rain, and the buildup of methane (CH₄). CO elevates concentrations of CH₄ and tropospheric ozone (O₃) by chemical reactions with the atmospheric constituents (i.e., the hydroxyl radical) that would otherwise assist in destroying CH₄ and O₃.

Chlorofluorocarbons (CFCs): A family of inert non-toxic and easily liquified chemicals used in refrigeration, air conditioning, packaging, and insulation or as solvents or aerosol propellants.

¹ Some of the definitions shown here are taken from the *Carbon Dioxide and Climate Glossary* produced by the Carbon Dioxide Information Analysis Center of Oak Ridge National Laboratory.

Because they are not destroyed in the lower atmosphere, they drift into the upper atmosphere where their chlorine components destroy ozone.

Climate Change: The long-term fluctuations in temperature, precipitation, wind, and all other aspects of the Earth's climate.

Deforestation: The removal of forest stands by cutting and burning to provide land for agricultural purposes, residential or industrial building sites, roads, etc. or by harvesting trees for building materials or fuel.

Enteric Fermentation: Fermentation that occurs in the intestines. For example, methane emissions produced as part of the normal digestive processes of ruminant animals is referred to as "enteric fermentation."

Flux: Rate of substance flowing into the atmosphere (e.g. lbs/ft²/second).

Global Warming Potential (GWP): Gases can exert a radiative forcing both directly and indirectly: direct forcing occurs when the gas itself is a greenhouse gas; indirect forcing occurs when chemical transformation of the original gas produces a gas or gases which themselves are greenhouse gases. The concept of the Global Warming Potential has been developed for policy-makers as a measure of the possible warming effect on the surface-troposphere system arising from the emissions of each gas relative to CO₂.

Greenhouse Effect: A popular term used to describe the roles of water vapor, carbon dioxide, and other trace gases in keeping the Earth's surface warmer than it would be otherwise.

Greenhouse Gases: Those gases, such as water vapor, carbon dioxide, tropospheric ozone, nitrous oxide, and methane that are transparent to solar radiation but opaque to infrared or longwave radiation. Their action is similar to that of glass in a greenhouse.

Hydrofluorocarbons (HFCs): HFCs are substitutes for CFCs and HCFCs which are being phased-out under the *Montreal Protocol on Substances that Deplete the Ozone Layer*. HFCs may have an ozone depletion potential (ODP) of zero, however, they are very powerful greenhouse gases. For example, HFC-23 and HFC-134a have a GWPs of 10,000 and 1,200 respectively.

Methane (CH₄): Following carbon dioxide, methane is the most important greenhouse gas in terms of global contribution to radiative forcing (18 percent). Anthropogenic sources of methane include wetland rice cultivation, enteric fermentation by domestic livestock, anaerobic fermentation of organic wastes, coal mining, biomass burning, and the production, transportation, and distribution of natural gas.

Nitrous Oxide (N₂O): Nitrous oxide is responsible for about 5 percent of the total contribution in 1990 of all greenhouse gases to radiative forcing. Nitrous oxide is produced from a wide variety of biological and anthropogenic sources. Activities as diverse as the applications of nitrogen fertilizers and the consumption of fuel emit N₂O.

Nitrogen Oxides (NO_x): One form of odd-nitrogen, denoted as NO_x is defined as the sum of two species, NO and NO₂. NO_x is created in lightning, in natural fires, in fossil-fuel combustion, and in the stratosphere from N₂O. It plays an important role in the global warming process

due to its contribution to the formation of ozone (O_3).

Nonmethane Volatile Organic Compounds (NMVOCs): NMVOCs are frequently divided into methane and non-methane compounds. NMVOCs include compounds such as propane, butane, and ethane (see also discussion on Volatile Organic Compounds).

Ozone (O_3): A molecule made up of three atoms of oxygen. In the stratosphere, it occurs naturally and it provides a protective layer shielding the Earth from ultraviolet radiation and subsequent harmful health effects on humans and the environment. In the troposphere, it is a chemical oxidant and major component of photochemical smog.

Perfluorinated Carbons (PFCs): PFCs are powerful greenhouse gases that are emitted during the reduction of alumina in the primary smelting process. Eventually, PFCs are to be used as substitutes for CFCs and HCFCs. PFCs have a GWP of 5,400.

Radiative Forcing: The measure used to determine the extent to which the atmosphere is trapping heat due to emissions of greenhouse gases.

Radiatively Active Gases: Gases that absorb incoming solar radiation or outgoing infrared radiation, thus affecting the vertical temperature profile of the atmosphere. Most frequently cited as being radiatively active gases are water vapor, carbon dioxide, nitrous oxide, chlorofluorocarbons, and ozone.

Stratosphere: Region of the upper atmosphere extending from the tropopause (about 5 to 9 miles altitude) to about 30 miles.

Trace Gas: A minor constituent of the atmosphere. The most important trace gases contributing to the greenhouse effect include water vapor, carbon dioxide, ozone, methane, ammonia, nitric acid, nitrous oxide, and sulfur dioxide.

Troposphere: The inner layer of the atmosphere below about 15 km, within which there is normally a steady decrease of temperature with increasing altitude. Nearly all clouds form and weather conditions manifest themselves within this region, and its thermal structure is caused primarily by the heating of the Earth's surface by solar radiation, followed by heat transfer by turbulent mixing and convection.

Volatile Organic Compounds (VOCs): Volatile organic compounds along with nitrogen oxides are participants in atmospheric chemical and physical processes that result in the formation of ozone and other photochemical oxidants. The largest sources of reactive VOC emissions are transportation sources and industrial processes. Miscellaneous sources, primarily forest wildfires and non-industrial consumption of organic solvents, also contribute significantly to total VOC emissions.

GLOSSARY: CHEMICAL SYMBOLS AND CONVERSION FACTORS

1. The columns below list symbols and their associated chemical compounds or meanings:

<u>Symbol</u>	<u>Compound</u>
CH ₄	Methane
N ₂ O	Nitrous Oxide
CO	Carbon Monoxide
NO _x	Nitrogen Oxides
CO ₂	Carbon Dioxide
CO ₂ -C	Carbon Dioxide in units of Carbon
—C	— in units of Carbon
N ₂ O-N	Nitrous Oxide in units of Nitrogen
—N	— in units of Nitrogen

2. The columns below show compounds and conversions by molecular weight equivalents to other compounds.

<u>To Convert:</u>	<u>To:</u>	<u>Multiply by:</u>
tons CO ₂ -C	tons CO ₂	44/12
tons CH ₄ -C	tons CH ₄	16/12
tons CO-C	tons CO	28/12
tons N ₂ O-N	tons N ₂ O	44/28
tons NO _x -N	tons NO _x	46/14

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ERRATA SHEETS

Attached are the correction sheets for the *States Workbook: Methodologies for Estimating Greenhouse Gas Emissions(1995)*

If there are any other errors in the Workbook, please contact:

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CORRECTIONS TO THE STATES WORKBOOK: METHODOLOGIES
TO ESTIMATE GREENHOUSE GAS EMISSIONS

Corrections to Workbook Chapter 1

Table 1-2

- The conversion factor for ethanol should be 0.0764 (Btu/gallon) not 0.764 (Btu/gallon)

Corrections to Workbook Chapter 3

Table 3-2. Methane Emission Factors for Activities

Sector	Activity Data (MMBTU)	Emissions Factor (lbs CH ₄ /MMBTU)		
		Low	High	Median
Oil & Gas Production				
Oil	Oil Production	0.0007	0.0117	0.0062
Gas	Gas Production	0.1072	0.1958	0.1515
Oil & Gas: Venting and Flaring	Oil & Gas Produced ^a	0.0070	0.0326	0.0198
Crude Oil Transportation and Refining				
Transportation	Oil Tankered	0.0017	0.0017	0.0017
Refining	Oil Refined	0.0002	0.0033	0.0017
Storage Tanks	Oil Refined	0.00005	0.0006	0.0003
Natural Gas Processing, Transport, and Distribution				
Gas Processing, Transmission, and Distribution	Gas Consumption	0.1329	0.2751	0.2040
^a Emissions are based on total production of oil and gas.				
Source: IPCC/OECD, 1992				

Corrections to Workbook Chapter 4

Page 4-6

Example Total coal mine methane emissions for Illinois are calculated as follows:

(million cf)	<u>Low</u>	<u>High</u>
Underground:	7,514	8,923
Surface:	516	1,547
Post-mining (underground):	658	1,033
Post-mining (surface):	<u>129</u>	<u>206</u>
Total:	8,817	11,709

$$\text{Avg.} = (8,817 + 11,709)/2 = 10,263 \text{ million cf}$$
$$10,263 \text{ million cf} \times 20.66 \text{ tons/million cf} = 212,034 \text{ tons CH}_4$$

Corrections to Workbook Chapter 5

Page 5-2, Step 2

- For the equation to estimate "Waste in Place", the units for state population should be provided in "head" instead of "1,000 head".

Page 5-5

Example Methane generated at small landfills for a nonarid state that has waste in place at small landfills of 5.0 million tons would be estimated as follows:

$$\text{Small landfills: } 0.35 \text{ (ft}^3/\text{ton/day)} \times 5 \text{ million tons} = 1.75 \text{ million ft}^3/\text{day}$$

$$= 1.75 \text{ million ft}^3/\text{day} \times 0.0077 \frac{\text{tons CH}_4/\text{yr}}{\text{ft}^3/\text{day}} = 13,475 \text{ tons CH}_4/\text{yr}$$

Corrections to Workbook Chapter 7

Please include the following table in the section as "Table 7-13. Methane Conversion Factors for Other Manure Management Systems."

STATES	DAIRY	ANIMAL TYPES			OTHER
		BEEF	SWINE	OTHER	
AK	75%	0%	0%	10%	
AL	0%	0%	0%	0%	
AR	0%	0%	0%	0%	
AZ	10%	0%	10%	10%	
CA	10%	0%	10%	0%	
CO	0%	90%	10%	0%	
CT	0%	0%	10%	0%	
DE	0%	0%	0%	0%	
FL	0%	0%	0%	10%	
GA	18%	0%	10%	10%	
HI	10%	0%	10%	90%	
IA	10%	0%	20%	10%	
ID	10%	10%	10%	0%	
IL	10%	0%	10%	0%	
IN	0%	0%	0%	0%	
KS	0%	0%	0%	0%	
KY	0%	0%	0%	10%	
LA	11%	0%	0%	10%	
MA	0%	0%	0%	10%	
MD	0%	0%	0%	0%	
ME	0%	0%	0%	10%	
MI	10%	0%	10%	10%	
MN	0%	0%	20%	0%	
MO	0%	0%	0%	0%	
MS	11%	0%	10%	20%	
MT	10%	0%	10%	0%	
NC	0%	20%	0%	10%	
ND	0%	0%	0%	0%	
NE	12%	0%	0%	0%	
NH	0%	0%	0%	0%	
NJ	0%	0%	0%	10%	
NM	0%	0%	0%	10%	
NV	0%	0%	0%	10%	
NY	0%	10%	0%	10%	
OH	10%	0%	10%	0%	
OK	40%	0%	0%	0%	
OR	20%	0%	20%	0%	
PA	0%	0%	0%	20%	
RI	0%	0%	0%	10%	
SC	0%	0%	0%	0%	
SD	0%	0%	0%	0%	
TN	20%	0%	20%	20%	
TX	0%	0%	0%	10%	
UT	0%	0%	0%	10%	
VA	0%	0%	0%	10%	
VT	0%	0%	0%	0%	
WA	0%	0%	0%	20%	
WI	0%	0%	0%	30%	
WV	10%	0%	10%	0%	
WY	10%	0%			

Corrections to Workbook Chapter 10

Average Annual Accumulation of Dry Matter as Biomass in Plantations

Forest Types		Average Annual Increment in Biomass (t dm/acre/yr)
Tropical	<i>Acacia</i> spp.	6.7
	<i>Eucalyptus</i> spp.	6.5
	<i>Tectona grandis</i>	3.6
	<i>Pinus</i> spp.	5.1
	<i>Pinus caribaea</i>	4.5
	Mixed Hardwoods	3.0
	Mixed Fast-Growing Hardwoods	5.6
	Mixed Softwoods	6.5
Temperate	Douglas Fir	2.7
	Loblolly Pine	1.8

Source: Derived from IPCC, 1994

Table 10-2
Aboveground Dry Matter in Tropical Forests
(t dm/acre)

Moist Forest		Seasonal Forest		Dry Forest	
Primary	Secondary	Primary	Secondary	Primary	Secondary
102.6	84.8	62.5	53.5	26.8	11.2

Source: Derived from IPCC, 1994

Table 10-3
Aboveground Dry Matter in Temperate and Boreal Forests
(t dm/acre)

	Temperate Forests		Boreal Forests
	Evergreen	Deciduous	
Primary	131.6	111.5	73.6
Secondary	98.1	78.1	53.5

Source: Derived from IPCC, 1994

Table 10-4
Carbon in Forest Soils
(tons C/acre)

Forest Type			
Tropical	Moist	Seasonal	Dry
	51.3	44.6	26.8
Temperate	Evergreen	Deciduous	
Primary	59.8	59.8	
Secondary	53.5	53.5	
Boreal			
Primary	91.9		
Secondary	82.5		

Source: Derived from IPCC, 1994

Note: See Table 1-3 of Birdsey (1992) for region-specific values of forest soil carbon in the U.S.

Table 10-5
Average Annual Biomass Uptake by Natural Regeneration
(t dm/acre)

Region	Forest Types					
	Moist Forests		Seasonal Forests		Dry Forests	
	0-20 yrs	20-100 yrs	0-20 yrs	20-100 yrs	0-20 yrs	20-100 yrs
Tropical	3.6	0.40	2.2	0.22	1.8	0.11

Note: Growth rates are derived by assuming that tropical forests regrow to 70 percent of undisturbed forest biomass in the first twenty years. All forests are assumed to regrow to 100 percent of undisturbed forest biomass in 100 years. Assumptions on the rates of growth in different time periods are derived from Brown and Lugo, 1990.

Temperate	0-20 yrs	20-100 yrs	
Evergreen	1.3	1.3	
	0.89	0.89	
Boreal	0.45	0.45	

Source: Derived from IPCC, 1994

Note: Temperate and boreal forests actually require considerably longer than 100 years to reach the biomass density of a fully mature system. Harmon et al. (1990), for example, report carefully designed simulations indicating that a 100-year old stand of douglas fir would contain only a little over half the biomass of a 450-year old growth stand of the same species. There is also evidence that growth rates in temperate and boreal systems are more nearly linear over different age periods than is the case for tropical systems. Nabuurs and Mohren (1993) suggest that growth rates for several different species in temperate and boreal zones rise slowly and peak at ages of 30 - 55 years and decline slowly thereafter. This suggests that using the same default values for 0-20 years and 20-100 years may be a reasonable first approximation. Nabuurs and Mohren (1990) also illustrate that growth rates may vary as much as a factor of ten for stands of the same species and age, depending on site-specific conditions.

Table 10-6
Annual Soil Carbon Accumulation in Temperate and Boreal Forests
(tons C/acre/yr)

Temperate		Boreal
Evergreen	Deciduous	
0.58	0.58	0.89

Source: Derived from IPCC (1994).

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- If necessary, enter the Biomass Conversion/Expansion Ratio in tons of dry matter per cubic foot ($t\text{ dm}/ft^3$) in Column G. The default conversion ratio (or biomass density) is $0.016 t\text{ dm}/ft^3$ (see Table 1-2 of Birdsey, 1992 (provided at the end of this chapter) for some species-specific densities for the U.S.). In addition, an expansion factor should be applied if the timber harvest data do not account for all of the biomass that is destroyed during the harvest process, e.g., limbs, small trees, etc. The following default ratios can be used: 1.75 for undisturbed forests; 1.9 for logged forests; and 2 for unproductive forests (see Table 1-1 of Birdsey, 1992 (provided at the end of this chapter) for region- and forest type-specific expansion factors for the U.S.). If both conversion and expansion factors are needed, they can be combined by using ratios which are the product of the two: $0.027 t\text{ dm}/ft^3$ for undisturbed forests; $0.030 t\text{ dm}/ft^3$ for logged forests; and $0.031 t\text{ dm}/ft^3$ for unproductive forests.

page 10-8

- Enter the Aboveground Biomass Density in tons of dry matter per acre ($t\text{ dm}/acre$) after conversion in Column C. This figure includes any biomass not fully cleared (default value = 0) and the biomass regrowth in agricultural use (the default value is 4.5 tons dry matter per acre) or other use subsequent to clearing.

page 10-9

- Enter the Soil Carbon Content Before Conversion by forest or grassland type in Column B. See Table 10-4 for forest soil defaults. Defaults for grasslands are 26.8 tons/acre for tropical zones and 31.2 tons/acre for temperate zones.

Corrections to Workbook 12

Page 12-2, Step 2

- For the equation to estimate "BOD, Generated", the units for population should be provided in "head" instead of "1,000 head".

Corrections to Discussion Chapter 4

page D4-7

- The emissions factors in the box presented should read as follows:

<u>Basin</u>	<u>Emissions Factor (cf CH₄/ton of coal mined)</u>
Northern Appalachian	425 - 740
Central Appalachian	215 - 325
Black Warrior	2000 - 3000
Illinois Basin	160 - 190
Rockies & Southwest	370 - 470

Corrections to Discussion Chapter 10

Table D10-1
Aboveground Dry Matter in Tropical Forests
(t dm/acre)

Moist Forest		Seasonal Forest		Dry Forest	
Primary	Secondary	Primary	Secondary	Primary	Secondary
102.6	84.8	62.5	53.5	26.8	11.2

Source: Derived from IPCC, 1994

Table D10-2
Aboveground Dry Matter in Temperate and Boreal Forests
(t dm/acre)

	Temperate Forests		Boreal Forests
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Primary	131.6	111.5	73.6
Secondary	98.1	78.1	53.5

Source: Derived from IPCC, 1994

Table D10-3
Average Annual Accumulation of Dry Matter as Biomass in Plantations

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	<i>Pinus caribaea</i>	4.5
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	Mixed Fast-Growing Hardwoods	5.6
	Mixed Softwoods	6.5
Temperate	Douglas Fir	2.7
	Loblolly Pine	1.8

Source: Derived from IPCC, 1994

Table D10-5
Carbon in Forest Soils
(tons C/acre)

Forest Type	Moist	Seasonal	Dry
Tropical	51.3	44.6	26.8
Temperate	Evergreen	Deciduous	
	59.8 53.5	59.8 53.5	
Boreal			
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Source: Derived from IPCC, 1994

Table D10-6
Average Annual Biomass Uptake by Natural Regeneration
(t dm/acre)

Region	Forest Types					
	Moist Forests		Seasonal Forests		Dry Forests	
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Tropical	3.6	0.40	2.2	0.22	1.8	0.11

Note: Growth rates are derived by assuming that tropical forests regrow to 70 percent of undisturbed forest biomass in the first twenty years. All forests are assumed to regrow to 100 percent of undisturbed forest biomass in 100 years. Assumptions on the rates of growth in different time periods are derived from Brown and Lugo, 1990.

Temperate	0-20 yrs	20-100 yrs
Evergreen	1.3	1.3
Deciduous	0.89	0.89
Boreal	0.45	0.45

Source: Derived from IPCC, 1994

Note: Temperate and boreal forests actually require considerably longer than 100 years to reach the biomass density of a fully mature system. Haccion et al. (1990), for example, report carefully designed simulations indicating that a 100-year old stand of douglas fir would contain only a little over half the biomass of a 450-year old growth stand of the same species. There is also evidence that growth rates in temperate and boreal systems are more nearly linear over different age periods than is the case for tropical systems. Nabuurs and Mohren (1993) suggest that growth rates for several different species in temperate and boreal zones rise slowly and peak at ages of 30 - 55 years and decline slowly thereafter. This suggests that using the same default values for 0-20 years and 20-100 years may be a reasonable first approximation. Nabuurs and Mohren (1990) also illustrate that growth rates may vary as much as a factor of ten for stands of the same species and age, depending on site-specific conditions.

Table D10-7
Annual Soil Carbon Accumulation in Temperate and Boreal Forests
(tons C/acre/yr)

Temperate		Boreal
Evergreen	Deciduous	
0.58	0.58	0.89

Source: Derived from IPCC (1994).