# TECHNICAL GUIDELINES
# VOLUNTARY REPORTING OF GREENHOUSE GASES
# (1605(b)) PROGRAM

OFFICE OF POLICY AND INTERNATIONAL AFFAIRS
UNITED STATES DEPARTMENT OF ENERGY

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# Technical Guidelines for Voluntary Reporting of Greenhouse Gases Program
# Chapter 1, Emission Inventories

## Part A: Introduction

Outline

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# Technical Guidelines Chapter 1, Part A: Introduction

## 1.A.1 Overview

On February 14, 2002, the President directed the Secretary of Energy, in consultation with the Secretary of Commerce, the Secretary of Agriculture, and the Administrator of the Environmental Protection Agency, to propose improvements to the current voluntary emission reduction registration program under section 1605(b) of the 1992 Energy Policy Act. The improvements were to enhance measurement accuracy, reliability and verifiability, working with and taking into account emerging domestic and international approaches.

In response to this charge, the Department of Energy (DOE), in consultation with the other agencies, has revised the reporting Guidelines for the Voluntary Reporting Program in two parts:

- General Guidelines
- Technical Guidelines (calculating emissions and reductions)

The purpose of the General Guidelines is to establish the procedures and requirements for filing voluntary reports. The purpose of the Technical Guidelines is to define permissible methods of calculating reportable emissions and reductions. The Technical Guidelines are, in turn, divided into two chapters:

- Chapter 1, Greenhouse Gas Emissions Inventory Guidelines
- Chapter 2, Greenhouse Gas Emission Reductions Guidelines

The Inventory Chapter is intended to be primarily a document in which possible methods of estimating emissions and sequestration from the sources most likely to be encountered are reviewed and rated. These Guidelines have a secondary purpose of acting as a guide for reporters on how to estimate emissions, complementing the many excellent works already in the public domain that cover this issue. The Inventory Chapter therefore avoids a detailed, guidebook-like approach unless the estimation methods are not in the public domain.

## 1.A.2 Purposes and Principles

In preparing emissions inventories, reporters will be required to make many decisions, small and large. The DOE is therefore providing extensive guidance on how to calculate and report greenhouse gas emissions. No set of guidelines, however, can provide explicit guidance on every decision that reporters may confront. While the General and Technical Guidelines endeavor to provide guidance on the most important points, there will frequently be another layer of complexity that the reporter must resolve. There will also, inevitably, be cases and issues that the Guidelines have not addressed.

On those occasions when explicit guidance is not provided, reporters should decide how to act based upon achieving the overarching objective of credibility. Only a report that is broadly held to be credible will have future utility and achieve the shared objectives of both the reporter and

the DOE. The overarching purpose of the Guidelines themselves is to define the set of choices that are most likely to produce a credible report. In defining a credible report, the DOE has tried to rely on the principles listed below. In making decisions for themselves, reporters should also rely on these principles.

**Accuracy**. Reports should accurately characterize the emissions of the reporter. In choosing emissions estimation methods, reporters should endeavor to use the most accurate method.

Accuracy, however, has another dimension. Resources, both human and financial, that can be devoted to inventory preparation are inevitably limited. In deploying limited resources, reporters should emphasize the emission sources that account for the largest share of total emissions at the possible expense of minor sources.

**Objectivity**. An emissions inventory should attempt to objectively and fairly describe the emissions of the reporter. The reporter should strive to produce a report that is akin to one that would be submitted by a knowledgeable but disinterested third party, describing the emissions situation of the reporter, rather than one written by an agent who puts the most favorable construction on a given set of facts or selectively chooses those facts that favor a particular interest.

**Completeness**. Reporters should strive to report on all applicable emissions sources and sequestration within the boundaries of the reporting entity, subject to the provisions of the General Guidelines.

**Verifiability**. “Verifiability” means that the methods chosen, the application of the methods, and the data used should be, in principle, accessible to verification by a third party, whether or not such verification actually takes place. In part, this implies preservation of data; in part this means documenting data, methods, and the application of methods with sufficient transparency; and in part this implies choosing approaches that can be explained and documented.

**Consistency**. Reporters should be consistent in their choice of rules. Consistency has two primary aspects:

- *Intertemporal Consistency*. Estimation methods should be applied consistently over time.
- *Intratemporal Consistency*. Estimation methods and data quality tests should, to the extent possible, be applied consistently in different parts of the entity. Rules on inclusion and exclusion of sources within the entity's boundary should be applied consistently, subject to the provisions of the General Guidelines.

## 1.A.3 Contents of the Inventory Chapter of the Technical Guidelines

The Inventory Chapter of the Technical Guidelines consists of nine parts, of which this is the first. The contents of the nine parts are summarized as follows:

**A. Introduction** describes the contents of the Inventory Chapter, with special reference to specific problems that reporters face in estimating emissions and sequestration, and describes both the approach adopted by the Technical Guidelines and the Department's thinking in adopting this approach.

**B. Collecting Information** provides guidance on entity boundaries and describes where and how reporters may gather the information necessary to construct their reports.

**C. Stationary Source Combustion** provides guidance on reporting greenhouse gas emissions from stationary combustion of fossil fuels.

**D. Mobile Sources** provides guidance on reporting greenhouse gas emissions from mobile sources. This includes the use of ethanol as a transportation fuel.

**E. Industrial Processes** provides guidance on a wide range of industrial process emissions sources, including emissions from mining, oil and gas production, and several chemical industry processes, and emissions from landfills and other sources of anaerobic decomposition.

**F. Indirect Emissions** provides guidance on estimating greenhouse gas emissions from purchases of electricity, steam, and hot or chilled water.

**G. Geologic Sequestration** provides guidance on the reporting of engineered carbon dioxide ($CO_2$) sequestration, including both enhanced oil recovery and sequestration of carbon dioxide streams.

**H. Agricultural Emissions and Sequestration**, prepared by the U.S. Department of Agriculture, provides guidance on estimating greenhouse gas emissions and soil carbon sequestration from agricultural sources and sinks (ethanol fuels are covered in Part D, Mobile Sources).

**I. Forestry Emissions and Sequestration,** prepared by the U.S. Department of Agriculture, provides guidance on estimating forest carbon sequestration and emissions from forests, woody biomass, and the wood product sector.

## 1.A.4 The Emissions Rating System

### 1.A.4.1 Summary

The President's charge to DOE specified that the Department should propose reforms to improve the "accuracy, reliability, and verifiability" of reported emissions. To contribute to achieving this

objective, the revised Guidelines require reporters who wish to register their reductions to "rate" their data and emissions estimation methods, and establishes minimum standards for the methods and data used to calculate reporters' overall emissions. This approach has been adopted to resolve a number of difficulties associated with adapting emissions inventory methods to the problem of calculating "entity" emissions and using such entity estimates to register reductions. In particular, this approach is intended to make the estimation of registered reductions more accurate, reliable and verifiable.

The emissions rating system is an *ordinal* rating of emission estimation methods by sector and emission source. The best available method, based on the four evaluation criteria of accuracy, reliability, verifiability and practical application, is usually rated "A," and given a value of four points. An A rating is restricted to methodologies where computations are based on a preponderance of values indicative of on-site conditions over multiple periods. The next best method – or best method in those cases where no methodology qualifies for an A rating - will be rated "B" and given a value of three points; the next best rated "C" and given a value of two points; and the least accurate method rated "D" and given a value of 1 point.[1]

Reporters should assign the rating provided by the Technical Guidelines to each source for each year in which emissions are reported. The average rating (weighted by emissions) of all reported emissions and sequestration must be 3.0 or higher in the base period and any year in which reductions are reported in order for the reductions or sequestration to qualify as "registered reductions."

### 1.A.4.2 Ratings

The Technical Guidelines describe numerous methods of estimating emissions of greenhouse gases. The methods are generally considered in combination with the information or activity data needed to implement the method so as to provide the greatest accuracy, reliability, verifiability and practicality of application. The Technical Guidelines provide ratings for combinations of methods and information used to apply the methods.

The rating system is an *ordinal* rating system with four values, A through D. The rating system is ordinal in the sense that A is considered "better" than B, B is "better" than C, and C is "better" than D. The highest rated method is believed by the Department to be the best method available, based on its evaluation criteria as shown in Table 1.A.1, for a particular emissions source in a given sector. However, two A-rated methods for different sources may not be comparable. Both will be the best method available, but in one case the best method available may be highly accurate, and in another case less so.

[1] The concept of ordinal rating is mentioned in the World Resources Institute's GHG Protocol (though the concept is not developed there). Ordinal ratings are also used by the U.S. Environmental Protection Agency's *Compendium of Air Pollutant Emissions Factors* (AP-42). Note, however, that the ordinal ratings in the AP-42 handbook are conceptually different from the ordinal ratings described in the Technical Guidelines. The AP-42 ratings are intended to indicate the extent to which the published emissions factor is supported by empirical evidence, and are intended to be comparable across the publication. In the Technical Guidelines, the rating generally applies to the combination of emissions factor and activity data, and is not directly comparable from one emission source to another.

There are four possible ratings that may be applied to estimation methods. Table 1.A.1 provides a general description of the criteria used to set the four ratings for particular sources within the Technical Guidelines.

**Table 1.A.1. Description of Ratings for Measurement and Estimation Methods**

| Rating | Points | Typical Description |
|---|---|---|
| A | 4 | Continuous direct measurement (CEM) of actual emissions source; or emissions factor based upon multiple, recent, regularly repeated, on-site, direct measurements of sources, multiplied by measured activity data. Activity data measure the actual relevant activity, rather than an indirect indicator of that activity (for instance, fuel consumption rather than purchases). |
| B | 3 | Emissions factor based on limited direct measurements of source or representative sample multiplied by measured activity data. Activity data measure actual use, rather than purchases (if applicable). |
| C | 2 | Default emissions factor multiplied by measured activity data; or emissions factor based on single measurement multiplied by estimated activity data. |
| D | 1 | Default emissions factor multiplied by estimated activity data or static one-time monitoring. |

There will be estimation methods not covered in the Technical Guidelines for various reasons. For example, the estimation method may not have been developed at the time the Guidelines were written, the source to which the method applies may not be included in the Guidelines, the greenhouse gas may represent a relatively small source such as methane released from forests or the authors of the Technical Guidelines may be unaware of the existence of a particular method or source.

Reporters may request DOE approval for the use of estimation methods not included in the Technical Guidelines if the methods cover sources not described in the Guidelines, or if the proposed methods provide more accurate results – or may be more cost effective – for the reporter's specific circumstances than the methods described in the Guidelines. If a reporter wishes to propose the use of a method that is not described in the Guidelines, the reporter must submit a description of the method, an explanation of how the method is implemented (including data requirements), evidence of the method's validity and accuracy, and a suggested rating for the method to DOE's Office of Policy and International Affairs (with a copy to the Energy Information Administration (EIA)). DOE reserves the right to deny the request, or to assign its own rating to the method. By submitting this information, the reporter grants permission to DOE to incorporate it in a future revision of the Guidelines.

### 1.A.4.3 Inventory Weighted Average Rating

The reporter shall divide the reported emissions and sequestration into categories, also called subentities, based on the sources and estimation methods used and assign a rating to each category. For the purposes of calculating an overall weighted average rating, the reporter shall use the absolute value of sequestration or change in carbon stock (i.e., sequestration is converted into a positive number and added to emissions). The reporter shall also convert all emissions

from particular greenhouse gases into carbon dioxide equivalents, using the 100-year Global Warming Potentials published by the Intergovernmental Panel on Climate Change.[2]

The reporter shall assign a rating drawn from the Technical Guidelines to each category of emissions and sequestration. The reporter shall multiply the points of the rating (drawn from Table 1.A.1 above) by the share of each category in total emissions and sequestration. The inventory's average rating is the sum of the reporter's ratings for each category, weighted by each category's share in total emissions.

Example:
A firm has three emissions sources:

| | Actual Emissions/Sequestration | $CO_2$ Equivalent |
|---|---|---|
| Energy-related carbon dioxide | 1,000 mt $CO_2$, rated "A" | 1,000 mt $CO_2E$ |
| Energy-related methane | 2 mt $CH_4$, rated "C" | 46 mt $CO_2E$ |
| Energy-related nitrous oxide | 1 mt $N_2O$, rated "C" | 296 mt $CO_2E$ |
| Sequestration | -100 mt $CO_2$, rated "C" | 100 mt $CO_2E$ |

Total emissions and sequestration for purposes of obtaining a single overall weighted rating:
(1,000) + (46) + (296) + (100) = 1,442 mt $CO_2E$

| | | |
|---|---|---|
| Energy-related $CO_2$ | (1,000/1,442) * 4 | = 2.77 |
| Energy related $CH_4$ | (46/1,442) * 2 | = 0.06 |
| Energy related $N_2O$ | (296/1,442) * 2 | = 0.41 |
| Sequestration $CO_2$ | (100/1,442) * 2 | = 0.14 |
| Weighted Average Rating: | | 3.38 |

The reporter shall calculate an inventory weighted average rating for each year of emissions reported to the Voluntary Reporting Program. If the reporter uses the same estimation methods for multiple reporting years (which would normally be the case), then the rating should remain relatively stable, baring substantial change in relative emission quantities from the various sources. If the reporter changes estimation methods, then the ratings should change to reflect the different estimation methods in use for each year.

If a reporter is seeking to register reductions, the weighted average rating for emissions for both the base period and the year used to calculate such reductions should be greater than or equal to 3.0. The choice of the value for the weighted average reflects DOE's belief that methods given an A or B rating are sufficiently accurate to serve as the basis for entity-wide reporting, while methods given a C or D rating should be used only for those gases or sources that represent a small share of the reporting entity's total emissions.

[2] Source: Intergovernmental Panel on Climate Change, *Climate Change 2001: The Scientific Basis* (Cambridge University Press, 2001), p. 47.

### 1.A.4.4 Objectives of Emissions Rating System

The emissions rating system is designed to achieve the following objectives:

- Help achieve the President's stated objective of improving the "accuracy, reliability, and verifiability" of reported emissions.
- Ensure that total reported emissions are as accurate as possible, given the available estimation methods for the actual array of sources.
- Create an incentive for reporters to use more accurate methods.
- Ensure that the cost of emissions estimation for particular sources can be commensurate with each source's importance in a reporter's inventory.
- Ensure that implementation is practical.

### 1.A.4.5 Issues Associated with Activity Reporting for Small Emitters

The General Guidelines contain provisions that allow small emitters (those emitting under 10,000 metric tons carbon dioxide equivalent per year) to register reductions based on specific activities rather than comprehensive entity-wide inventories. Small emitters choosing to register reductions will need to meet other criteria established in the General Guidelines, including determining the total annual emissions and sequestration associated with the specific activities, the net emission changes associated with those activities, and certification that the changes are not likely to cause emission increases elsewhere in the entity's operations.

Small emitters choosing to register reductions from specific activities should follow the additional guidelines contained in Chapter 2, Reporting Reductions. The inventory methods described in this Chapter can be applied at various levels including project, activity, and entity. Some of the issues associated with activity reporting include:

- **Setting Boundaries.** Entity boundaries are frequently more transparent than the boundaries of an activity within an entity. In some cases, the activity will be self-contained and relatively easy to define. Examples include specific plants or product lines, and specific commodity crops or livestock operations within a farm. In any case, all reporting entities must clearly define the boundaries of their entity and their subentities in a manner that is consistently applied in each year's report

- **Certification that emissions will not increase elsewhere within the entity's operation.** In order to register reductions from activity reports, a small entity must certify that emissions elsewhere in the entity's operations do not increase as a result of the activities being reported. While this may not require a full entity-wide inventory, some analysis will be required for the entity to make this certification.

## 1.A.5 Covered Gases and Global Warming Potentials

The General Guidelines prescribe that reporters must report their emissions of carbon dioxide, methane, nitrous oxide, perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur

hexafluoride (SF6). They may separately report, but not register, their emissions of Chlorofluorocarbons (CFCs) [10 CFR § 300.6 (i)]. The guidelines further prescribe:

> Emissions and sequestration should be reported in terms of the mass (not volume) of each gas, using metric units (e.g., metric tons of methane). Entity-wide and subentity summations of emissions and reductions from multiple sources must be converted into carbon dioxide equivalent units using the global warming potentials for each gas in the International Panel on Climate Change's Third Assessment (or most recent) Report, as specified in the Technical Guidelines. [10 CFR § 300.6 (j)]

PFCs, HFCs and CFCs are not gases, but groups of gases. For reporting purposes, reporters shall report emissions of HFCs and PFCs from the list shown on Table 3, page 47 and CFCs from the list shown on page 388 of the Intergovernmental Panel on Climate Change's *Climate Change 2001: The Scientific Basis*[3] or a more recent Assessment Report, if published.

For reporting or registering reductions, the reporter (and the Department) will sum emissions across greenhouse gases using the 100-year global warming potentials shown in Table 1.A.2 below. Only reductions of carbon dioxide, methane, nitrous oxide, perfluorocarbons (PFCs), hydrofluorocarbons (HFCs), and sulfur hexafluoride (SF6) emissions may be registered, however.

DOE may add or subtract gases from this list, pursuant to the provisions of the General Guidelines and any subsequent revisions thereto.

### Table 1.A.2. 100-Year Global Warming Potentials for Greenhouse Gases

| Gas | Chemical Formula | 100-Year Global Warming Potential |
|---|---|---|
| Carbon Dioxide | $CO_2$ | 1 |
| Methane | $CH_4$ | 23 |
| Nitrous Oxide | $N_2O$ | 296 |
| | | |
| **Hydroflourocarbons** | | |
| HFC-23 | $CHF_3$ | 12,000 |
| HFC-32 | $CH_2CF_3$ | 550 |
| HFC-41 | $CH_3F$ | 97 |
| HFC-125 | $CHF_2CF_3$ | 3,400 |
| HFC-134 | $CH_2FCF_3$ | 1,100 |
| HFC-134a | $CH_3FCF_3$ | 1,300 |
| HFC-143 | $CHF_2CH_2F$ | 330 |
| HFC-143a | $CF_3CH_3$ | 4,300 |
| HFC-152 | $CH_2FCH_2F$ | 43 |
| HFC-152a | $CH_3CHF_2$ | 120 |
| HFC-161 | $CH_3CH_2F$ | 12 |
| HFC-227ea | $CF_3CHFCF_3$ | 3,500 |
| HFC-236cb | $CH_2FCF_2CF_3$ | 1,300 |
| HFC-236ea | $CHF_2CHFCF_3$ | 1,200 |

[3] Intergovernmental Panel on Climate Change, *Climate Change 2001: The Scientific Basis* (Cambridge University Press, 2001), pp. 47, 388.

| Gas | Chemical Formula | 100-Year Global Warming Potential |
|---|---|---|
| HFC-236fa | $CF_3CH_2CF_3$ | 9,400 |
| HFC-245ca | $CH_2FCF_2CHF_2$ | 640 |
| HFC-245fa | $CHF_2CH_2CF_3$ | 950 |
| HFC-365mfc | $CF_3CH_2CF_2CH_3$ | 890 |
| HFC-43-10mee | $CH_3CHFCHFCF_2$ | 1,500 |
| | | |
| Sulfur Hexaflouride | $SF_6$ | 22,200 |
| | | |
| **Perfluorocarbons** | | |
| Perflouromethane | $CF_4$ | 5,700 |
| Perflouroethane | $C_2F_6$ | 11,900 |
| Perfluoropropane | $C_3F_8$ | 8,600 |
| Perfluorobutane (FC 3-1-10) | $C_4F_{10}$ | 8,600 |
| Perfluorocyclobutane | $c\text{-}C_4F_8$ | 10,000 |
| Perfluoropentane | $C_5F_{12}$ | 8,900 |
| Perfluorohexane (FC 5-1-14) | $C_6F_{14}$ | 9,000 |
| | | |
| **Chlorofluorocarbons** | | |
| CFC-11 (trichlorofluoromethane) | $CCl_3F$ | 4600 |
| CFC-12 (dichlorodifluoromethane) | $CCl_2F_2$ | 10600 |
| CFC-13 (monoclorotrifluoromethane) | $CClF_3$ | 14000 |
| CFC-113 (Freon 113) | $CCl_2FCClF_2$ | 6000 |
| CFC-114 (dichlorotetrafluoroethane) | $CClF_2CClF_2$ | 9800 |
| CFC-115 (monochloropentafluoroethane) | $ClF_3CClF_2$ | 7200 |

Source: Intergovernmental Panel on Climate Change, *Climate Change 2001: The Scientific Basis* (Cambridge University Press, 2001), p. 47; 388.41, 45-6, 388-9.

## 1.A.6 Revisions to Emissions Inventory Reports

Reporters may revise previously submitted inventory reports if the revision is necessary to:

- Correct significant material errors and omissions detected after the report was accepted by EIA; or
- To adopt an estimation method from the list approved by DOE that has a higher rating than the method previously used to develop the inventory and that necessitates changes in historical emissions to maintain consistency of the time series.

Participants may submit such corrected reports at any time, as long as they are accompanied by a description of the changes made, the significance of their effects on the emission quantities reported, and an explanation of why they were needed.

## Technical Guidelines for Voluntary Reporting of Greenhouse Gases Program
## Chapter 1, Emission Inventories

# Part B: Collecting Information

Outline

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# Technical Guidelines Chapter 1, Part B: Collecting Information

## 1.B.1 Overview

An entity's inventory report shall include the entity's direct and indirect emissions released into the atmosphere minus any sequestration of greenhouse gases from the atmosphere that occurred over the year covered by the inventory. Inventories are expressed as metric tons of carbon dioxide ($CO_2$) equivalent emissions in a specified year. An entity's inventory report shall separately identify the data on all direct emissions, sequestration and indirect emissions. If a reporter chooses to report emissions associated with CFCs, it must report all such emissions separately using the special methods for CFC destruction in Chapter 2.

This chapter provides a general overview of estimating greenhouse gas emissions in order to report to the Voluntary Reporting Program. Reporters preparing inventories must:

- Identify reporting boundaries for the entity.
- Identify potential sources of emissions and sequestration of greenhouse gases.
- Identify the estimation methods and information sources necessary to estimate emissions.
- Prepare the emissions inventory.

Each of those activities is discussed in the subsequent sections of this Part B of Chapter 1, and the Part closes with a brief consideration of institutional issues related to developing an annual entity-wide emissions inventory. Participation in the Voluntary Reporting Program is envisaged as a multi-year, long-term activity, and reporters are encouraged not to view reporting as a one-time event, but as a continuing process.

## 1.B.2 Identifying Reporting Boundaries

### 1.B.2.1 Who Can Report

The General Guidelines provide that:

Entity means the whole or part of any business, institution, organization, government agency or corporation, or household that:

(1) Is recognized under any U.S. Federal, State or local law that applies to it;
(2) Is located and operates, at least in part, in the United States; and
(3) The emissions of such operations are released, at least in part, in the United States.[4]

[4] General Guidelines, § 300.2.

### 1.B.2.2 Organizational Boundaries

The General Guidelines provide:(a) Each reporting entity must disclose in its entity statement the approach used to establish its organizational boundaries, which should be consistent with the following guidelines:

(1) In general, entities should use financial control as the primary basis for determining their organizational boundaries, with financial control meaning the ability to direct the financial and operating policies of all elements of the entity with a view to gaining economic or other benefits from its activities over a period of many years. This approach should ensure that all sources, including those controlled by subsidiaries, that are wholly or largely owned by the entity are covered by its reports. Sources that are under long-term lease of the entity may, depending on the provisions of such leases, also be considered to be under the entity's financial control. Sources that are temporarily leased or operated by an entity generally would not be considered to be under its financial control.

(2) Entities may establish organizational boundaries using approaches other than financial control, such as equity share or operational control, but must disclose how the use of these other approaches results in organizational boundaries that differ from those resulting from using the financial control approach.

(3) Emissions from facilities or vehicles that are partially-owned or leased may be included at the entity's discretion, provided that the entity has taken reasonable steps to assure that doing so does not result in the double counting of emissions, sequestration or emission reductions. Emissions reductions or sequestration associated with land, facilities or other sources not owned or leased by an entity may not be included in the entity's reports under the program unless the entity has long-term control over the emissions or sequestration of the source and the owner of the source has agreed that the emissions or sequestration may be included in the entity's report.

(4) If the scope of a defined entity extends beyond the United States, the reporting entity should use the same approach to determining its organizational boundaries in the U.S. and outside the U.S.

(b) Each reporting entity must keep separate reports on emissions or emission reductions that occur within its defined boundaries and those that occur outside its defined boundaries. Entities must also keep separate reports on emissions and emission reductions that occur outside the United States and those that occur within the United States.

(c) An entity that intends to register its entity-wide emissions reductions must document and maintain its organizational boundary for accounting and reporting purposes.[5]

[5] General Guidelines, § 300.4 Selecting organizational boundaries.

## 1.B.3 Identifying Potential Sources of Emissions and Sequestration

### 1.B.3.1 Direct and Indirect Emissions

The General Guidelines provide that reporters are obligated to report on all greenhouse gas emissions and sequestration from sources and sinks owned and operated by their reporting entity, termed *direct* emissions, as well as *indirect* emissions arising from the use of electricity, hot or chilled water, and steam. The Technical Guidelines identifies common emissions and sequestration sources for which well-defined estimation methods exist.

Having identified the activities or organizational units whose emissions should be excluded or included in reporting, the next step is to identify potential sources of emissions in those areas. This section will help the reporter to identify which activities are most likely to involve emissions of greenhouse gases. The most common activity, and usually the largest source of emissions, is the combustion of fossil fuels such as natural gas, propane, gasoline, diesel fuel, jet fuel, fuel oil, coal, and coke. There are, however, many other emissions sources.

Emissions may be characterized as "direct" or "indirect." An entity's direct emissions are those emissions from sources in the possession of the entity at the time the gases are emitted. An example of a direct emission is exhaust from an automobile that the reporter owns and drives. An indirect emission is an emission that occurs from a source owned by a party other than the reporter, but is affected by the reporter's action. For example, emissions produced during the generation of electricity, which is produced by a third party and consumed by the reporter, are indirect emissions.

More specifically, the General Guidelines provide:

> Indirect emissions means greenhouse gas emissions from stationary or mobile sources outside the organizational boundary that occur as a direct consequence of an entity's activity, including but not necessarily limited to the emissions associated with the generation of electricity, steam and hot/chilled water used by the entity.[6]

Indirect emissions from purchased electricity, steam, hot or and chilled water, which are to be included in emission inventories and may be the source of registered reductions, are discussed in Part F of this chapter.

The General Guidelines also provide that emissions from other indirect sources may be reported separately utilizing applicable reporting methods as described in the Technical Guidelines. Other indirect sources may include downstream emissions (and reductions) claimed by the manufacturers of energy-efficient products; upstream (fuel cycle) emissions from the manufacture and transportation of fuels; or energy "embedded" in energy-intensive products manufactured by others, such as aluminum, steel, cement, or plastics. The reporting of these other indirect emissions entails considerable complexity because:

[6] General Guidelines, § 300.2 Definitions, "Indirect Emissions."

- Indirect emissions (or reductions) may be reported by more than one party.
- Reporting on indirect emissions, by definition, requires information on the activities and emissions of other parties. This information may be difficult or impossible to obtain. Estimates of information made in the absence of precise information are often necessarily uncertain and, to a degree, subjective.

Emissions from these other sources of indirect emissions are not to be incorporated into total emissions and may not be the source of registered emission reductions, unless explicitly permitted by the Guidelines.

### 1.B.3.2 Fossil Fuel Usage

Whenever a fuel containing carbon is combusted (oxidized), the combustion products will include carbon dioxide (the most common greenhouse gas), and may also include trace amounts of methane and nitrous oxide. Because the carbon content of fossil fuels is generally constant (plus or minus a few percent), the reporter will generally be able to calculate and report the resulting greenhouse gas emissions if the quantity of fossil fuels consumed is known.

In most cases, commercial fossil fuels (natural gas, petroleum products, coal, coal coke, and petroleum coke) will be purchased and combusted by the reporter. This activity will generate accounting records (of the purchase), and may generate facilities management records relating to the use of the fuel, and/or environmental management records (such as continuous emissions monitoring data) characterizing emissions of regulated pollutants caused by combustion of the fuel.

Almost all U.S. households, farms, public agencies, and enterprises can be reasonably expected to purchase and combust fossil fuels. For most reporters, carbon dioxide emitted from the combustion of fossil fuels will be the largest source of direct greenhouse gas emissions.[7] In general, if a reporter can identify the quantity and heating value of fossil fuels and quantity of electricity purchased by the reporting entity, most of the greenhouse gas emissions of the organization can be easily calculated.

Fossil fuel use can be divided conceptually into stationary source combustion, mobile source combustion, and non-fuel use. In principle:

- Stationary source combustion is the burning of fuels in fixed facilities.
- Mobile source combustion is defined as the use of energy to transport people and materials from one physical location to another.[8]

[7] For many manufacturers and firms in service industries, fossil fuel consumption will be the largest source of direct emissions. Indirect emissions from electricity use, however, may be considerably larger than direct emissions from fossil fuel consumption for these reporters.
[8] Included are automobiles, trucks, buses, motorcycles, trains, subways, and other rail vehicles, aircraft, ships, barges, and other waterborne vehicles.

- Non-fuel use includes use of fossil fuels as feedstocks, raw materials, lubricants, or solvents. Often, fossil fuel used for non-combustion purposes still causes some fraction of the carbon locked in the fuel to be emitted to the atmosphere.

Methods for estimating emissions from stationary source combustion and non-fuel use are described in Part C of this chapter. Methods for estimating emissions from mobile sources are described in Part D. An overview of those categories is provided below.

#### 1.B.3.2.1 Stationary Source Combustion

Fuel is burned in stationary facilities for a variety of purposes. Among the most common functions to be considered are:

- Coal, natural gas, propane, or heating oil for water heating or cooling, and for space heating.
- Coal, natural gas, diesel, and fuel oil for electric power generation.
- Natural gas, coal, or petroleum for raising industrial process steam, process heat, or cogeneration.
- Diesel fuel, propane, or natural gas to drive engines (such as diesels) to provide motive power for equipment such as compressors or pumps.
- Oil or gas pipelines with pumps and compressor stations burning natural gas or diesel.

Reporters should also be aware of special situations that are discussed at length in Part C, "Stationary Source Combustion." These include:

- Byproduct fuel combustion such as flaring, or burning of catalyst coke in petroleum refining and the chemical industries, or the use of coke oven gas in the steel industry.
- Own use of fossil fuels that are not purchased such as natural gas or petroleum use in oil production operations, refinery gas in petroleum refining, and various intermediate chemicals in chemical processing.
- Combustion of petroleum-based waste fuels such as used motor oil or tire-derived fuels.
- Combustion of biofuels or renewable fuels such as wood or wood waste and ethanol.
- Use of fossil fuels as feedstocks (with special accounting requirements), as in coke manufacturing and petrochemical processing.

Reporters should scrutinize the activities of their organization to ascertain if any of those special situations apply to them.

Fossil fuel combustion also causes emissions of small amounts of methane and nitrous oxide, although those trace emissions are rarely measured. Reporters may estimate them approximately.

#### 1.B.3.2.2 Mobile Source Emissions

Mobile sources encompass not only the most obvious transportation candidates such as planes, trains, and automobiles. It also includes plant vehicles such as forklifts, construction equipment such as bulldozers, farm equipment such as combines and tractors, and public service vehicles

such as buses, fire trucks, and ambulances. If your organization uses any of these vehicles, it is likely that the vehicles are combusting fossil fuels (usually gasoline, diesel fuel, and/or jet fuel).

Some of the most common mobile source emissions and the fuel(s) being combusted are:

- Motor vehicles, including cars and trucks, typically burning motor gasoline or diesel.
- Locomotives usually burning diesel fuel.
- Aircraft usually burning jet fuel and occasionally aviation gasoline.
- Construction or farm equipment, normally burning diesel fuel.
- On-site materials-handling vehicles such as forklifts, burning propane or diesel.

There are also a number of special situations in transportation that may be applicable to particular reporters, but are unlikely to be of general importance. They include:

- Combustion of fuels partially derived from biomass fuels, such as gasohol.
- Combustion of alternative fossil fuels, including methanol and natural gas.
- Use of international bunker fuels for aviation and marine transportation.
- Electricity use in the transportation sector.

Those special situations are discussed at greater length in Part D, "Mobile Sources."

While carbon dioxide will constitute the preponderance of mobile source emissions, transportation equipment will also normally emit small amounts of nitrous oxide and methane. While equipment built after 1976 with catalytic converters will produce moderate amounts of nitrous oxide emissions, even equipment without catalytic converters will produce trace amounts.

**1.B.3.2.3 Non-Fuel Use of Fossil Fuels**.

There are a wide range of non-fuel uses of fossil fuels, some of which produce significant quantities of greenhouse gas emissions. Uses that produce small amounts of emissions within the boundary of the reporter may be excluded from the inventory under the *de minimis* provisions described in the General Guidelines (§300.2 and §300.6). In most other cases, emissions within the boundary of the reporter from non-fuel use of fossil fuels must be included in the inventory. The appropriate treatment of certain specific non-fuel uses of fossil fuels is described below:

- *Use of natural gas or petroleum products as petrochemical feedstocks*. Feedstock use of fossil fuels is generally limited to the chemical industry. Some uses such as ammonia are non-sequestering, that is, carbon is emitted to the atmosphere and must be reported. Other uses such as ethylene to polyethylene are largely sequestering, that is, the carbon remains conserved in the end product and need not be reported.

- *Use of coal to make coke*. Coke making is largely limited to integrated steel mills; there are less than 40 coke plants in the United States. Most, though not all, of the carbon in coke making is conserved into outputs such as coke, coal tars, and coke oven gas used as

fuel, which are largely oxidized later in the steel-making process. If coke or byproducts are sold, however, the subsequent oxidation is no longer a direct emission of the coke-maker but should be reported by the entity in control of the coke or byproducts when the emission occurs unless excluded as a *de minimis* emission.

- *Use of coke as a reduction agent*. Coke is often used in the processing of metals, including steel, lead, and copper, as a reduction agent—it is burned under conditions of incomplete combustion to make carbon monoxide, and the carbon monoxide is used to remove oxygen from the ore, which creates carbon dioxide emissions. The carbon dioxide emissions should be reported by the entity in control of the coke when the emission occurs unless excluded as a de minimis emission.

- *Carbon black manufacture*. There are several plants in the United States that use natural gas or oil to make carbon black. About a third of the carbon is conserved in the product, the balance emitted to the atmosphere. The manufacturer need only report the carbon dioxide emitted during manufacturing of the carbon black unless excluded as a de minimis emissions.

- *Use of coke in anode production*. Aluminum smelters use petroleum coke to make sacrificial anodes, which are vaporized as part of the aluminum smelting process, resulting in carbon dioxide emissions. As with other non-fuel uses of fossil fuels, the carbon dioxide emissions should be reported by the entity in control of the coke when the emission occurs, unless excluded as a de minimis emission.

- *Lubricants and greases (especially motor oil) used in engines and machinery*. Used lubricants are often captured and recycled. Lubricants that evaporate or are burned (in two stroke engines, for example) generate carbon dioxide emissions, while lubricants that are lost to the environment may be presumed to oxidize to carbon dioxide in the long run. Emissions from the burning of lubricants should be reported unless excluded as de minimis, while emissions from evaporation are likely to be very small and may be excluded from inventories.

- *Use of carbon-based solvents.* When hydrocarbon-based solvents evaporate, the chemicals generally decompose in the atmosphere into carbon dioxide. While solvent usage is common, emissions are usually so small that they can be ignored. However, where solvent use is a significant part of an entity's operations, such as dry cleaning plants and certain industrial processes, these emissions must be estimated and, if not excludable as de minimis, they must be included in the entity's emissions inventory.

### 1.B.3.3 Industrial Process Emissions

There are numerous industrial process emission sources that collectively emit significant quantities of greenhouse gases, although most are found in only one or two industries. This necessitates that reporters scan a long list of sources to identify the few that are applicable to their particular situation. Among the more important industrial process emissions are:

- *Carbon dioxide emissions from cement manufacture.* Cement manufacturers combust fuels to provide process heat and also to calcine limestone into lime, a process that drives off carbon dioxide. Cement manufacturers should calculate and report calcining emissions.

- *Other limestone-related emissions.* Lime manufacturers also calcine limestone. Some flue gas desulfurizers ("scrubbers") used to remove sulfur dioxide react limestone with sulfur and emit additional carbon dioxide.[9]

- *Multiple sources from iron and steel producers, including the use of coke and mineral reducing agents.*

- *Carbon dioxide released in the manufacture of lime in the Kraft pulping process when calcium carbonate is burned in kilns or calciners.* This carbon dioxide is biomass carbon originating in wood. Because this is a biogenic source, reporters need not include carbon dioxide from the Kraft pulping process of lime production in their emissions inventories.

- *HFC-32 from freon production.* Producers of HCFC-22 (Freon-22) have historically emitted significant quantities of the greenhouse gas HFC-32 as a by-product.

- *HFC-134a from motor vehicle air conditioning.* Air-conditioned motor vehicles built after 1993 usually use the refrigerant HFC-134a, a potent greenhouse gas. Modern air conditioning systems do not leak significantly, so the HFC-134a generally remains in the vehicle, and authorized dealers are required to recycle the refrigerant during repairs. If and when the air conditioning system fails, however, the refrigerant will frequently leak into the atmosphere. Vehicles that are scrapped or lost in accidents will often lose their refrigerant to the atmosphere. A discussion of calculating HFC emissions from motor vehicles is included in Part D, "Mobile Sources."

- *Nitrous oxide from adipic and nitric acid production.* U.S. producers of adipic acid and nitric acid have historically emitted significant (but controllable) quantities of nitrous oxide as a by-product.

- *Various gases from semiconductor manufacturing.* Semiconductor manufacturers use several high-GWP greenhouse gases in manufacturing, and produce by-product emissions of perfluorocarbons (PFCs) and sulfur hexafluoride ($SF_6$).

- *PFCs from aluminum manufacturing.* Aluminum manufacturers generate by-product emissions of PFCs, and some magnesium producers may use $SF_6$ as a cover gas to prevent oxidation of the magnesium.

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[9] Scrubbers are usually associated with large, coal-fired power generation equipment. Reporters estimating carbon dioxide emissions using continuous emission monitoring will have the carbon dioxide from scrubbers automatically included in the stack gas they are monitoring. Reporters using mass balance to estimate emissions from power plants with scrubbers will have to separately estimate scrubber carbon dioxide emissions and add them to the fuel-related carbon dioxide emissions.

- *HFC-32 from freon production.* Producers of HCFC-22 (Freon-22) have historically emitted significant quantities of the greenhouse gas HFC-32 as a byproduct.

- *HFC-134a from motor vehicle air conditioning.* Air-conditioned motor vehicles built after 1993 usually use the refrigerant HFC-134a, a potent greenhouse gas. Modern air conditioning systems do not leak significantly, so the HFC-134a generally remains in the vehicle, and authorized dealers are required to recycle the refrigerant during repairs. If and when the air conditioning system fails, however, the refrigerant will frequently leak into the atmosphere. Vehicles that are scrapped or lost in accidents will often lose their refrigerant to the atmosphere. A discussion of calculating HFC emissions from motor vehicles is included in Part D, "Mobile Sources."

- *Nitrous oxide from adipic and nitric acid production.* U.S. producers of adipic acid and nitric acid have historically emitted significant (but controllable) quantities of nitrous oxide as a byproduct.

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- *PFCs from aluminum manufacturing.* Aluminum manufacturers generate byproduct emissions of PFCs, and some magnesium producers may use $SF_6$ as a cover gas to prevent oxidation of the magnesium.

- *Refrigerants.* Residential, commercial, and industrial reporters may use HFCs as a refrigerant for space cooling, refrigeration, or industrial cooling processes. Quantities of HFCs may leak into the atmosphere through equipment failure or normal leakage.

- *Sulfur hexafluoride emissions from breaker switches.* Electric power operators may use sulfur hexafluoride as an insulating gas. Quantities may leak into the atmosphere under various circumstances.

Reporters undertaking any of these activities may reasonably expect to have industrial process emissions and should calculate and report them. Methods of estimating emissions from industrial processes are described in Part E, "Industrial Processes."

### 1.B.3.4 Mining, Oil and Gas Production Emissions

There are substantial non-combustion sources of emissions of greenhouse gases from this sector:

- *Methane emissions from coal mining*. Coal seams typically have methane trapped within them. In some cases shale or non-commercial coal that coexists with commercial coal seams may also have trapped methane. Coal mining will typically release methane into the atmosphere, though some portion may be captured or used, and in some cases coal companies will act to drain captured methane in advance of mining.

- *Emissions from oil and gas production and transportation*. Natural gas is largely methane, and the process of producing and transporting natural gas generates fugitive methane emissions. In addition, some natural gas fields contain significant admixtures of carbon dioxide, which is sometimes separated and vented to the atmosphere. Crude oil may also contain dissolved methane, and crude oil production, transportation, and refining may be accompanied by fugitive methane emissions. Methane emissions from the transportation of petroleum products including gasoline and diesel fuels are thought to be insignificant.

Estimation of non-combustion emissions from mining and from oil and gas production is described in Part E, "Industrial Processes."

### 1.B.3.5 Waste Treatment and Handling

Materials of biological origin, whether plant or animal, will normally be subject to bacterial decomposition. If that decomposition takes place anaerobically, that is, in the absence of oxygen, anaerobic bacteria will predominate, and will produce methane gas as a waste product.

Anaerobic decomposition is commonplace, but it remains the reporter's obligation to report the resulting methane emissions if the decomposing biomass is generated within the reporter's organizational boundary. Methods for estimating methane and nitrous oxide emissions from the treatment of livestock waste are covered in Part H, "Agricultural Emissions and Sequestration." Methods for estimating emissions from other types of waste treatment are discussed in Part E, "Industrial Processes." Those sources include:

- *Landfills.* There are thousands of landfills in the United States, mostly containing municipal solid waste. The U.S. Environmental Protection Agency (EPA) regulates emissions from larger landfills, and many landfills are equipped with methane recovery systems that serve multiple purposes, including safety, odor control, and limiting emissions of urban air pollutants.

- *Industrial waste*. Some food processors (particularly beer manufacturers) have large quantities of biological waste products, some portion subject to anaerobic decomposition, generating methane.

- *Wastewater treatment*. Wastewater treatment may sometimes involve anaerobic decomposition, and hence methane emissions. Wastewater that contains human or animal waste may also contain significant quantities of nitrogen, some of which may decompose into nitrous oxide. Under the right circumstances, wastewater treatment plants may thus emit significant quantities of nitrous oxide.

### 1.B.3.6 Indirect Emissions from Purchased Electricity, Steam, and Hot or Chilled Water

Indirect emissions, as defined above, are emissions produced by another entity, but resulting from the reporter's activities. The General Guidelines provide that indirect emissions of electricity, steam, and heated or chilled water must be reported. See Part F, "Indirect Emissions."

#### 1.B.3.6.1 Electricity

Almost all reporters will purchase and use electricity, but reporting indirect emissions raises an important question: How does the reporter learn about the emissions of the party who generated the electricity that was purchased? For almost all electricity users, the Guidelines specify that indirect emission estimates be based on the regional indirect emissions factors specified by DOE. These factors are based on the average emissions intensity of the electricity generated in that region, regardless of the specific circumstances of individual electricity users. The only exception is if an individual electricity user has a contract to purchase power generated by one or more specific plants. In such cases, the entity may use the average emissions associated with the power delivered from these plants.

#### 1.B.3.6.2 Steam

Steam purchases are less common than electricity purchases.[10] Steam-related emissions fall into two categories:

- In some cities (e.g., San Francisco), district heating utilities sell steam to commercial buildings and light industrial customers in a manner similar to natural gas and electric utilities. It may be possible to learn or infer emissions from the vendor, or in some cases default emissions factors may be necessary.

- Industrial customers, large buildings, malls, and campuses will often purchase steam from a plant dedicated to their specific requirement. This arrangement is frequently part of a cogeneration project, and customers will often know or be able to find out specific information on the fuel use and/or emissions of their vendor.

#### 1.B.3.6.3 Hot and Chilled Water

Many reporters will purchase hot and/or chilled water for heating and cooling purposes, respectively. In many cases, reporters will maintain and operate heating and cooling equipment on their premises. Methods for estimating these emissions can be found in Part C, "Stationary Combustion." Other reporters will purchase hot and/or chilled water that is generated by a plant or specific equipment that is owned and operated by another entity. As is the case with electricity and steam purchases, reporters in these circumstances may need to obtain information from their suppliers in order to estimate the emissions associated with these purchases. If this information is not available, reporters can use default factors to make an estimate of the emissions associated with their purchased hot and/or chilled water.

[10] In-house steam generation for space heating or cogeneration is very common. Emissions from this source can be conveniently quantified by measuring the amount of fuel that has been combusted to raise the steam. Purchasing steam (or heat) from another party is less common.

### 1.B.3.7 Other Indirect Emissions

Reporting entities may choose to report other forms of indirect emissions, such as emissions associated with employee commuting, materials consumed or the end uses of products produced, although such other indirect emissions are not to be included in the entity's total emissions and may not be the basis for registered emission reductions. All such reports of other forms of indirect emissions must be distinct from reports of indirect emissions associated with purchased energy and must be based on emission measurement or estimation methods identified in the Technical Guidelines or otherwise approved by DOE.

### 1.B.3.8 Forests, Woody Biomass, and Wood Products

Forests, wood biomass systems, and wood products can be significant sources or sinks for carbon such as during harvesting or reforestation. Wood releases carbon dioxide as part of the oxidation process. Management activities can reduce carbon emissions and increase the levels of carbon stored. Estimation methods for Forestry-related carbon emissions and storage are provided in Part I. Examples of management practices that influence carbon storage include, but are not limited to, the following:

- Afforestation of agricultural land can lead to large increases in carbon capture and storage by the treated area.

- Reforestation (regeneration of harvested forest land) can accelerate the natural regeneration process and provide for the establishment of fast-growing species.

- Agroforestry can both sequester carbon and decrease requirements for fossil energy and energy-intensive chemicals in the production of food and fuel.

- Short-rotation woody biomass energy plantations can sequester carbon and provide fuel that displaces fossil fuels in the energy production process.

- Low-impact harvesting methods can decrease the emissions from soil disturbance and biomass decay that often follow timber harvest.

- Recycling and wood products management studies have indicated that the carbon contained in harvested trees follows several different paths after harvest. Of the carbon that reaches wood products, some remains only for a short time (1 to 5 years), but a significant amount remains stored in the wood products for long periods (on the order of decades) before returning to the atmosphere. Some of the carbon in wood products may be recycled or stored in landfills after the initial use is discontinued.

Methods of estimating sequestration and emissions from forests, woody biomass and wood products are covered in Part I, “Forestry Emissions.”

## 1.B.3.9 Agricultural Sources and Sinks

Agriculture has multiple sources of greenhouse gas emissions and carbon sequestration. Generally, the sources can be categorized by activities related to crop production and livestock. Estimation methods for each category are provided in Part H, "Agricultural Emissions and Sequestration." The categories are described briefly below.

### 1.B.3.9.1 Livestock Greenhouse Gas Sources

*Enteric fermentation.* Enteric fermentation is a normal digestive process in animals where microbial populations in the digestive tract break down food and excrete methane gas as a byproduct. Ruminant livestock—including cattle, sheep, and goats—have greater rates of enteric fermentation because of their unique digestive system, which includes a large rumen or fore-stomach where enteric fermentation takes place. In all animals, diet is an important determinant of the production of methane. For a further discussion see Section 4.1.2 of Part H, "Agricultural Emissions and Sequestration."

*Livestock waste.* Livestock waste can be managed in storage and treatment systems, or spread daily on fields in lieu of long-term storage. The magnitude of methane and nitrous oxide emissions from managed livestock waste depends on the conditions of waste handling and storage.

Installation of anaerobic digesters in livestock waste management systems can reduce methane emissions from livestock waste and provide an alternative renewable energy source. Therefore, this action spans the livestock waste management and indirect emissions estimation methods. Specific guidance is provided in Box 3.H.1 of Part H on estimating the impacts of applying this technology to livestock waste management systems.

### 1.B.3.9.2 Crop Production

*Rice cultivation.* In the United States, rice is grown exclusively on shallow, continuously flooded fields. Water-logged soils create conditions for anaerobic decomposition of organic matter, facilitated by methane emitting "methanogenic" bacteria. Methane from rice fields reaches the atmosphere in three ways: bubbling up through the soil, diffusion losses from the water surface, and diffusion through the vascular elements of plants.

*Nitrous oxide from agricultural soils.* Soil amendments that add nitrogen to soils drive the production of nitrous oxide. Amendments can be added to both crop and rangeland soils. Commercial fertilizer, livestock manure, sewage sludge, incorporation of crop residues, and cultivation of nitrogen-fixing crops all add nitrogen to soils. In addition, cultivating highly organic soils (i.e., histosols) enhances mineralization of nitrogen-rich organic matter, making more nitrogen available. Nitrogen can be converted to nitrous oxide and emitted directly in agricultural fields, or it can be transported through groundwater and run-off to other systems where it is later converted to nitrous oxide, thus causing indirect emissions.

*Lime application*. Lime is often added to agricultural soils to reduce acidic conditions. Lime contains carbonate compounds that release carbon dioxide through the bicarbonate equilibrium reaction when added to soils.

*Carbon dioxide emissions and sequestration on mineral soils.* The amount of carbon dioxide emissions and sinks in soils is related to the amount of organic carbon stored in soils. The net balance of carbon dioxide uptake and loss in soils is driven in part by biological processes, which are affected by soil characteristics and climate. In addition, land use and management affect the net balance of carbon dioxide through modifying inputs and rates of decomposition. Changes in agricultural practices such as clearing, drainage, tillage, crop selection, grazing, crop residue management, fertilization, and flooding can modify both organic matter inputs and decomposition, and thereby result in a net flux of carbon dioxide to or from soils.

C*arbon dioxide emissions from cultivation of organic soils*. Cultivation of organic soils causes oxidation of soil organic matter and carbon dioxide emissions. As in mineral soils, both carbon dioxide emissions and sequestration may occur in organic soils, although as long as organic soils are cultivated they continue to be a net source of carbon dioxide emissions.

Methods of estimating emissions and sequestration from crop production are covered in Part H, "Agricultural Emissions and Sequestration."

### 1.B.3.10 Geologic Sequestration

Sequestration refers to a family of methods for capturing and permanently isolating carbon dioxide from the atmosphere. Geologic sequestration normally falls into two categories:

- Intentional extraction of carbon dioxide from industrial processes or combustion exhaust streams, combined with placing the carbon in a form or location in which it will not be released into the atmosphere. This is likely to involve the injection of carbon dioxide into permanent underground storage.

- Injection of carbon dioxide into underground reservoirs as part of an enhanced oil recovery activity.

Most geologic sequestration activities are currently associated with enhanced oil recovery, which requires reporters to take care that the sequestration is not temporary and that carbon dioxide injected into the ground is not offset by its release elsewhere. Geologic sequestration issues are described in Part G, "Geologic Sequestration."

## 1.B.4 Preparing an Emissions Inventory Report

### 1.B.4.1 Needed Steps

Once a reporter has identified his or her organizational boundaries and the likely sources of emissions, the next step is to prepare an emissions inventory. To do this the reporter will need to:

- Identify prospective methods of estimating emissions from the relevant sources, and the information that would be potentially required to calculate emissions.

    - Identify information systems in which emissions information or activity data relevant to the estimation of emissions is already being collected or might feasibly be collected.

    - Identify organizational elements that have custody of the relevant information or that might be in a position to collect the information.

    - Collect the data, estimate emissions, prepare an inventory, and submit a report to the Energy Information Administration's Voluntary Reporting of Greenhouse Gases Program.

    - Develop a mechanism by which emissions data can be routinely collected and assembled into a verifiable entity-wide emissions estimate at an acceptable cost.

### 1.B.4.2 Estimating Emissions

Emissions of greenhouse gases may be measured in several different ways:

**Direct measurement** - by continuous or periodic measurement of emissions. To ensure consistency and reliability, reporters using any direct measurement data should ensure that their measurement systems are subject to periodic calibration practices. Due to the wide variety of emission sources and methods for measuring them, this guidance does not provide specific instruction on calibrating measurement systems for each emission source discussed herein.

Reporters to the Voluntary Reporting of Greenhouse Gases Program (1605(b) Program) that directly measure their emissions are expected to follow internal quality control assessments that verify the accuracy of their measurement systems. Specific, internationally accepted standard methods for measuring greenhouse gas emissions exist for some industries. Where specific methods exist, reporters are encouraged to follow them; where possible, this guidance refers reporters to readily available, published authorities that provide specific instruction of this nature.

In the absence of industry-specific standard methods, reporters should follow internationally accepted, generalized standard methods for managing and calibrating measurement systems. One such organization providing guidance for complying with internationally accepted standards is the International Organization for Standardization (ISO). Reporters seeking general guidance on methods for managing and calibrating measurement systems should consult the ISO's guidance document, *ISO 10012 - Measurement Management Systems - Requirements for Measurement Processes and Measuring Equipment*.[11] This document provides generic guidance designed to

[11] Available at web site: www.iso.ch.

help organizations establish and operate an effective measurement management system that features the following:

- Clearly specified measurement requirements that can be shown to be satisfied.
- Effective, accountable management that establishes quality objectives for the organization's metrological function.
- Defined and documented management of resources associated with the metrological function, including human resources, information resources and material resources.
- Clear guidelines for establishing, maintaining and documenting the accuracy, calibration and uncertainty associated with measurement equipment and procedures.
- Specific, controlled conditions under which to perform measurement processes.
- Procedures for ensuring continued conformity with established standards while maintaining and realizing opportunities for making improvements to the measurement system.

**Inferred measurement -** derived from a measurement or set of measurements made at a single point in time (typically for sources that are small and/or difficult to measure). Alternatively, direct or inferred measurements of an emission source at a particular point in time may be used to develop an "emissions factor" that links estimated emissions with a measurable activity that presumptively causes the emissions to occur. For example, if EPA's Office of Mobile Sources determines (based on testing sample vehicles) that a 1998 model car emits an average of 0.2 kg of nitrous oxide per mile traveled, this factor can be applied to vehicle travel data to estimate nitrous oxide emissions (i.e., multiply total miles traveled by emissions per mile).

**Mass balance -** calculate the quantities of emissions by measuring or calculating the quantities of a specific source, the individual source's compounds, reaction products, and outputs. For example, if 2 kilograms of HFC-134a was initially injected into an automobile air conditioner and three years later the remaining 1 kilogram is removed and recycled, one can safely assume that the other kilogram was emitted to the atmosphere.

No single method is feasible, best, or most accurate for all sources and situations. In most cases, the estimation method will need to be matched to the particular source. There are multiple considerations in making this determination, which include the following:

- **Availability of Information**. Many electric power generators and large industrial sources measure carbon dioxide emissions directly, using continuous emission monitors (CEMs), as required by Title IV of the Clean Air Act Amendments. Most entities track commercial fuel purchases.

- **Cost and feasibility**. Some methods may be extremely expensive, others infeasible. Reporters should choose methods that are sustainable over time.

- **Accuracy**. Some methods are more accurate than others, although accuracy is specific to a linkage of method and source.

- **Size of the source**. Simple, less accurate methods may be acceptable for small, uncontrollable sources.

- **Controllability and feasibility of reduction action**. If a reporter expects to show, now or in the future, that emissions from a particular source have been reduced, the credibility of his report will be enhanced by taking extra care with measuring current emissions from that source.

- **Variability and performance over time**. Emissions estimation methods should accurately reflect changes in emissions over time.

- **Ancillary benefits**. Reporters should consider opportunities for synergies in collecting greenhouse gas-related data along with other information. For example, systems that monitor emissions of regulated pollutants may be modified to monitor emissions of greenhouse gases; data systems for operational management and control may be modified to include activity data for emissions estimation.

Reporters should choose estimation methods that are most suitable for their particular circumstances. Collecting new data in the field may be necessary in some cases, but one should not automatically assume that such efforts will be necessary. A better first step is to consider what information systems are already in place, and try to ascertain what information is already being collected.

### 1.B.4.3 Using Existing Data Systems

Large organizations typically have multiple information systems that collect information relevant to estimating greenhouse gas emissions. These might include:

*Operational Data Systems*. Operational data may be defined as reporting on physical quantities of materials consumed or products manufactured. In contrast to financial data, which are always reported to headquarters, operational data are collected only if they are deemed useful for management information and control or necessary for regulatory purposes. If collected, operational data are often held at the facility or division level, and not reported to the reporter's headquarters. Much of the information deemed "of interest" to someone preparing a greenhouse gas emissions inventory falls into the category of operational data.

For example, fuel or energy consumption data are rarely independently reported to headquarters unless fuel costs are considered to be a "major" controllable cost element. Many energy-intensive industries have centralized energy management programs, but for other types of organizations this information is the province of facility or process managers. For public agencies or service industries, fuel use is often just another bill paid by the accountants.

Expensive transportation equipment such as aircraft, locomotives, vehicle fleets, and construction equipment will usually be carefully maintained and the maintenance supported by detailed records. An airline, for instance, must know the provenance of every spare part applicable to an aircraft, and know when every aircraft subsystem is due for scheduled maintenance. Maintenance records will often specify how many hours an aircraft has been flown, or how many miles a truck has been driven. Such information may be helpful in estimating

greenhouse gas emissions. In common with other operational data, however, maintenance and facilities management data are rarely forwarded up the organizational chain of command.

Most aluminum producers probably view output of aluminum as a key index, and plant managers report output data to headquarters. Exotic inputs such as $SF_6$ or HFC-134a are much less likely to be of interest to headquarters. If the relevant operational data are not reported to headquarters, inventory managers might visit with plant or facility managers to learn what types of information are available locally, and persuade them to begin forwarding such data. It is also possible that the information is already being reported, just through an unexpected reporting channel.

Inventory managers should be alert to the many not-so-obvious forms of reporting, and that "piggybacking" on existing reporting systems is generally the lowest cost way to get started in greenhouse gas emissions reporting. Some other systems that may exist include:

*Facilities Management and Maintenance Systems*. Many organizations use "facility management" to describe the function of supervising the operation and maintenance of building or equipment complexes. Facility managers are often responsible for energy consumption, and frequently keep detailed records of fuel use, equipment utilization, and maintenance. Those records will often prove useful in preparing an emissions report, provided one has access to the data.

*Financial Accounting Systems*. Nearly every institution has some type of financial accounting system, within which there are relevant subsystems that include the following:

- **Accounts payable.** These systems generally track how much money has been paid, the vendors to whom funds are paid, dates of payments, cost centers to which expenses are charged, and invoices against which payments have been rendered. In many cases the quantity of fuel or electricity purchased will be available either directly from the accounting system or indirectly from scrutiny of invoices. Accounts payable data may also indicate purchases of high-GWP gases such as sulfur hexafluoride, HFCs, or PFCs, if such gases are in use.

- **Inventory.** These systems may track stocks and changes in stocks of fuels and possibly high-value commodities. If firms have storage capacity and large stocks of petroleum or solid fuels, changes in inventory will be a more accurate indicator of actual consumption than fuel purchases. Firms may maintain inventories (and records) of high-GWP gases as well.

- **Contract records.** Energy services will frequently be purchased pursuant to contracts that may also contain useful information (e.g., prices and vendor names), which can be used to interpret accounts payable records. Aspects of fuel quality also may be specified in contracts.

Organizations differ greatly in how the accounting function is organized - from highly centralized at headquarters to decentralized in subsidiary units where only periodic summary financials are forwarded to the main unit. The information that is useful for inventory preparation is most likely to be found close to where actual bills are being paid. Consequently, it may be necessary for the persons responsible for greenhouse gas reporting to identify the appropriate

personnel to contact, ascertain what information they possess, and develop cooperative relationships to facilitate the greenhouse gas reporting effort.

*Environmental Reporting Systems.* Many organizations report emissions and environmental data to the EPA and other environmental agencies. Because greenhouse gas emissions are not currently subject to Federal regulation, there are no Federal requirements to report them as such. However, information systems currently used for other environmental reporting may also collect incidental information about greenhouse gas emissions, or possibly may be modifiable to collect greenhouse gas emissions data. For example:

- **Environmental Reporting**: **Clean Air Act.** There are about 2,000 facilities in the United States that are required to report sulfur dioxide and nitrogen oxide emissions to the EPA under provisions of the Clean Air Act Amendments of 1990, using continuous emission monitors. Those facilities are also required to report carbon dioxide emissions for calibration and verification purposes. Numerous other facilities are permitted to report emissions using other methods, including mass balance. Many gas-fired facilities report carbon dioxide emissions to EPA using strictly specified fuel-sampling procedures, and checked using tracking systems. This information is in the public domain.

- **Environmental Reporting: Criteria Pollutant Reporting**. Many facilities are required to report their emissions of criteria pollutants to State regulatory agencies, or alternatively to report expected future emissions for permitting purposes. This information, some of which may be in the public domain, can be useful to identify possible emissions of greenhouse gases. Nitrogen oxide and carbon monoxide emissions are generally indicative of combustion, probably of fossil fuels, and may help indicate where carbon dioxide is being emitted. Emissions of non-methane volatile organic compounds may be indicative of possible methane emissions. Data on emissions of certain greenhouse gases, particularly methane and carbon dioxide, are in some cases collected but not reported.

Environmental reporting is usually the province of environmental management or environmental safety and health groups. As in the case of financial reporting, environmental management may be centralized or decentralized. Organizations that operate in multiple countries or are subject to multiple regulatory jurisdictions tend to be organized around those jurisdictions.

*Safety reporting* is relevant to greenhouse gas reporting in several specialized contexts. Coal mine, petroleum, and landfill operators have an acute interest in avoiding methane hazards. Safety personnel track emissions, leak repairs, or equipment usage to identify hazards or compute safety metrics. More generally, safety personnel may collect operating data for the computation of safety metrics.

*Economic, Regulatory, and Trade Association Reporting*. Many large firms and facilities are required to report fuel consumption and industrial production to various government agencies, including the Department of Commerce, the DOE's Energy Information Administration (EIA), and the Federal Energy Regulatory Commission (FERC). Individual firm or facility reports are rarely in the public domain, although inventory managers can obtain copies of their own

company reports from the person submitting the report. Among the reporting systems that might be useful in specific instances are the following:

- Large electric power plants report fuel consumption and stocks to the EIA.
- Large regulated electric utilities, including public sector utilities, report to the FERC on FERC Form 1, which covers electric energy purchased and sold and also considerable amounts of enterprise-level data.
- Cement plants are surveyed on fuel consumption every two years by the Minerals Information Service of the U.S. Geological Survey (USGS), and report production to the USGS annually. The USGS also collects data on a range of limestone uses, which may be helpful in calculating emissions from the use of lime or limestone as a reducing agent.
- Oil refineries report fuel consumption to the EIA every other year.
- Coke plants report fuel consumption and output to the EIA every year.
- Natural gas producers and natural gas plants report to the EIA on gas balances, which include production, fuel consumption, and non-hydrocarbon gases removed every year.
- Many manufacturing establishments report physical production to the U.S. Census Bureau as part of the *Current Industrial Reports*. Many manufacturers also report additional data, including energy consumption data, to the Census Bureau as part of the *Annual Survey of Manufacturers*. A sample of establishments, including most large energy consumers, is asked every four years to report detailed information on energy consumption as part of the *Manufacturing Energy Consumption Survey* (MECS).
- Construction, mining, and oil and gas production establishments also report a range of data, including some energy data, to the U.S. Census Bureau.
- Several trade associations, notably the Integrated Solid Waste Management Association, the American Chemical Council, and the American Iron and Steel Institute, have organized energy data reporting programs among their members. Reporting of output data to trade associations is also common.

In most cases, individual establishment or facility data from these statistical programs are not in the public domain. Reporters may be able, however, to identify the internal corporate data systems (usually corporate compliance personnel) that support the reports filed for those programs, and adapt either the information or the system that collects the information for greenhouse gas reporting purposes.

*Tax Reporting*. Operating data may also emerge from tax reporting. Firms that produce, purchase, or sell products subject to royalties or excise taxes (e.g., transportation fuels), may have or be able to obtain operating data from those records. Other activities such as renewable

energy production and landfill methane operations are eligible for Federal or State income tax credits, which require collecting and specifying operating data for the tax authorities.

### 1.B.4.4 Identifying Organizational Elements

Having defined the scope of reporting, considered possible sources of emissions and sequestration, and determined what information is already collected by the organization, the next step is to define which organizational elements need to be involved in developing the inventory. While it is common to think of inventory development as being primarily a technical problem, experienced practitioners in large organizations tend to think of the technical problems as being one of the simplest aspects of inventory preparation. A more acute problem often is securing the consent and cooperation of the people and organizational units who actually possess the information needed to prepare an inventory. This task frequently requires tact, diplomacy, and senior management commitment.

### 1.B.4.5 Preparing a Report

The most difficult aspect of preparing an emissions report is usually collecting the necessary information. Actually preparing an emissions inventory and reporting emissions to the Energy Information Administration is largely an exercise in arithmetic, form filling, and the avoidance of egregious error. Reporters should pay attention, however, to the categorization of the information required by the Voluntary Reporting Program.

### 1.B.4.6 Developing a Reporting Mechanism

It may turn out that not all the needed information is already available. In some cases, new data collection systems may need to be funded and put in place. New data systems should, in general, be placed where there are people with access to the facilities and information needed to collect the data. The first step, however, is always to determine what can be accomplished with existing data and existing systems.

In either case, it is important to keep in mind that greenhouse gas emissions reporting under the program is not a “one off” exercise. The reporter should expect to be preparing emissions reports every year. *Ad hoc* arrangements and volunteer labor will tend to come unraveled if repeated too many times.

Hence, in organizing reporting, reporters should keep in mind methods for automating and institutionalizing the necessary information flows, and giving participants a stake in the success of the system. In this respect, organizing a greenhouse gas reporting system in a large organization reflects many of the institutional challenges endemic in motivating and coordinating action across a large organization. The longer-run requirements for a sustainable reporting system include:

- A person or group with responsibility, authority and resources to prepare an organizational emissions inventory to an adequate standard.

- Management “buy in.”
- Matching actual and potential emissions sources to particular organizational units, and to responsible individuals or groups within those organizational units.
- Identifying an estimation method for each emissions source, and data source(s) consistent with the chosen estimation method.
- Funding and organizational approvals so that the responsible party is empowered to collect or obtain the necessary data for each source and to estimate emissions or forward the data.
- Developing an information system (not necessarily computer-based) that permits the necessary information to flow to the persons responsible for preparing the inventory.

Quality assurance and verification to ensure that the correct sources are being measured using appropriate methods, to understand the quality of the underlying data being used, and to ensure that calculations are performed correctly and reported accurately.

## Part C: Stationary Source Combustion

Outline

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4. Common Sources: Methane and Nitrous Oxide

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6. Special Situations: Nonfuel Use of Fossil Fuels

# Technical Guidelines Chapter 1, Part C: Stationary Source Combustion

## 1.C.1 Overview

This section covers estimating emissions of greenhouse gases from stationary source combustion and also from non-fuel use of fossil fuels. In general, reporters can reasonably expect that over 95 percent of their GWP-weighted emissions from stationary source combustion will take the form of carbon dioxide ($CO_2$), with minor quantities of methane ($CH_4$) and nitrous oxide ($N_2O$) emissions.

Most stationary source combustion emissions will be caused by the combustion of commercial fossil fuels: coal, petroleum, and natural gas. Carbon dioxide emissions from the combustion of commercial fossil fuels may be accurately measured by the use of continuous emission monitors, if available, or by mass balance, properly applied. Emissions of methane and nitrous oxide from combustion are difficult to measure accurately, but fortunately are rather small.

There is also a range of special situations that are unlikely to be of importance to reporters generally, but may be significant for particular reporters. Those special situations include the combustion of non-standard fuels such as refinery gas, petroleum coke, or waste fuels such as lubricating oil or tire-derived fuel; combustion of biomass; and non-fuel use of fossil fuels. These special situations are discussed at the end of this section.

## 1.C.2 Estimation Methods

### 1.C.2.1 Overview

Stationary source combustion is defined as the burning of a fuel to produce heat or motive power using equipment in a fixed location. Stationary source combustion includes electric power generation, residential and commercial space heating or district heating, industrial process heating, cogeneration (also called “combined heat and power”), and powering engines for diverse purposes, including driving compressors and pumps.

Stationary source combustion almost always generates emissions of greenhouse gases because the fuel contains carbon, which is oxidized to form carbon dioxide. Almost all (98 to 99 percent) of the carbon in the fuel is typically oxidized to carbon dioxide and goes up the stack as an emission. In contrast with many other pollutants, carbon dioxide emissions can often be accurately estimated using mass balance calculations (see the explanation in the box, “How Mass Balance Works”). In addition, many large stationary source combustion sources in the United States (and effectively all large coal-fired units) are equipped with continuous emissions monitors (CEMs) that record carbon dioxide emissions and report their amounts to the U.S. Environmental Protection Agency (EPA).

Stationary source combustion also produces trace quantities of methane and nitrous oxide. Trace emissions of methane are derived from unburned or partially burned fuel and are most common when combustion temperatures are low and/or oxygen is deficient. High levels of combustion-related methane emissions are most probable when the fuel is heated but not combusted, causing complex hydrocarbons to break down into simpler components, including methane.

It is not entirely clear how and why nitrous oxide is emitted from combustion, but it appears to be a reaction product of nitrogen oxides ($NO_x$). The EPA reports that nitrous oxide emissions are more prevalent at lower combustion temperatures. Reporters, however, should devote the bulk of their effort to calculating carbon dioxide emissions because 95 to 99 percent of global warming potential-weighted emissions from stationary source combustion are usually attributable to carbon dioxide.

### How Mass Balance Works

Fossil fuels are predominantly composed of various forms of hydrocarbons. Hydrocarbons are molecules composed of hydrogen and carbon, linked together in various forms and with varying numbers of atoms. The most common forms of hydrocarbons found in fuels are "paraffinic" hydrocarbons, which have slightly more than two hydrogen atoms for each carbon atom, according to the general formula $C_xH_{2x+2}$.

Propane, for instance, has the chemical formula $C_3H_8$, or three atoms of carbon (C) and eight atoms of hydrogen (H). Since carbon has a atomic weight of 12, and hydrogen an atomic weight of one, the molecular weight of propane is (3*12)/((3*12) + (8*1)) = 36 + 8 = 44. Therefore, propane is 36/44 = 81.8 percent carbon by weight. When any hydrocarbon is burned (oxidized), the carbon atoms combine with atmospheric oxygen to form carbon dioxide ($CO_2$), while the hydrogen atoms combine with oxygen to form water vapor ($H_2O$). Burning propane produces the reaction:

$$C_3H_8 + 7O_2 \rightarrow 3CO_2 + 4H_2O$$

The three carbon atoms in each propane molecule end up in the atmosphere as three molecules of $CO_2$. To calculate the amount of $CO_2$ released when a fuel is burned, multiply the weight of the fuel by its carbon content and by the ratio of the molecular weights of $CO_2$ (12 + (2*16)) and the atomic weight of carbon (12), or (12 + (2*16))/12 = 44 / 12. For example, for each ton of propane burned 3.0 tons of $CO_2$ is emitted to the atmosphere (1 * 0.818 * (44/12) = 3.0).

The more complex hydrocarbons that make up liquid fuels and coal are generally about 85 percent carbon by weight, while natural gas is 75 percent carbon by weight. If the weight and chemical composition of the fuel are known, then $CO_2$ emissions can be accurately calculated using the mass balance approach. Even if only the weight and hydrocarbon share of the fuel are known, $CO_2$ emissions can still be calculated with reasonable accuracy.

There are three general methods for estimating emissions from stationary source combustion: direct measurement, mass balance, and inferring emissions from activity data and sample emissions measurement. For estimating carbon dioxide, mass balance and direct measurement (such as stack monitoring) can both produce accurate results. Inferred emissions can generally be expected to be less accurate, but are acceptable for estimating minor amounts of emissions from methane and nitrous oxide.

### 1.C.2.2 Direct Measurement

*Continuous Emissions Monitoring (CEM) for Regulatory Purposes*. Emissions monitoring requires inserting a probe into the exhaust stack of a combustion system and continuously measuring and recording concentrations of carbon dioxide and other gases. Actual emissions are estimated by calculating the density and flow rate of exhaust gases through the stack. Under the Clean Air Amendments of 1990 (CAAA), about 2,000 power plants and industrial boilers are required to install CEM equipment in their stacks and report emissions of carbon dioxide to the EPA.[12]

*Other Emissions Monitoring*. Reporters may monitor their stack emissions even when not required to by the CAAA. They may be complying with other environmental regulations or collecting boiler performance information. Reporters should use unregulated emissions monitoring data with caution, particularly for carbon dioxide. Moving from a concentration sample to an accurate estimate of mass emissions over time requires solving some challenging measurement and calibration problems that have already been solved for regulatory monitoring. Reporters who use monitoring data should ensure that the methods used and the quality of the data collected is comparable to data that would be acceptable to the EPA for reporting under Climate Leaders.

### 1.C.2.3 Mass Balance

Carbon dioxide emissions can usually be computed to an accuracy of five percent or better by using the following general formula:

$$CE = QF * CC * FC$$

Where

CE = carbon dioxide emissions (metric tons)
QF = quantity of fuel (measured in weight, volume, or heating value)
CC = carbon coefficient (a ratio, metric tons carbon dioxide per “unit” of fuel, as above)
FC = fraction combusted

Fuel quantity may be expressed in terms of weight (tons or pounds of fuel); volume (barrels, gallons, cubic feet, or cubic meters of fuel); or heating value (million Btu or joules, either higher heating value or lower heating value). The carbon coefficient for the fuel is the theoretical

[12] See the U.S. Environmental Protection Agency’s Acid Rain web site: www.epa.gov/airmarkets/arp/index.html.

maximum carbon dioxide emission rate expressed in terms of units of carbon dioxide per unit of fuel denominated by any of these measures. Often, as is the case in these guidelines, a default emission factor may be calculated by multiplying the carbon coefficient (CC) by the assumed fraction combusted (FC).

Given the diversity of possible measures, which measure should reporters actually use? In general, reporters should use the measure of fuel quantity that most accurately represents the characteristics of the fuel actually consumed by the reporter. Reporters should minimize the use of default values by substituting parameters based on actual measurements whenever possible.

**Table 1.C.1. Getting the Most Accurate Results from Mass Balance**

| **If the reporter knows…..** | **Fuel** | **Then calculate:** | Rating |
|---|---|---|---|
| Weight & carbon content | Coal | Weight x carbon content | A/B |
| Actual heating value | Coal | Heating value x emission factor | A/B |
| Weight only | Coal | Weight x default heating value x emission factor | C |
| Weight & carbon content | Oil | Weight x carbon content | A/B |
| Actual heating value | Oil | Heating value x emission factor | A/B |
| Weight only | Oil | Weight x assumed carbon content x emission factor | C |
| Volume & actual density | Oil | Volume x density x assumed carbon content | A/B |
| Volume only | Oil | Default heating value x emission factor | C |
| Heating Value | Gas | Heating value x emission factor | A |
| Volume only | Gas | Volume x default heating value x emission factor | B |

When the actual carbon content of the fuel is known (based on an ultimate analysis), the most accurate calculation of mass balance emissions is generally based on weight, although because the carbon content of a fuel (particularly coal) can vary considerably from one sample to another, a fairly intensive sampling program is required to produce the most accurate results. More commonly, the reporter will not know the carbon fraction of the fuel (or will not know it with sufficient precision), but will know the heating value (this would be typical of natural gas, coal, and some fuel oils). In this case, the most accurate mass balance calculation would be based on heating value and a default emission factor.

Liquid fuels, however, are often sold by volume alone, rather than by weight or heating value. If the reporter knows neither the heating value nor the carbon fraction of the fuel, the most accurate approach is to use actual density (since volume times density = weight.). It will also frequently be the case for some liquid fuels, such as diesel and gasoline, that *only* the volume of fuel is known. In those instances the reporter must multiply fuel volume by an assumed density and carbon content per ton, or alternatively, multiply fuel volume by an assumed heating value per unit volume and an emission factor expressed per unit heating value. Both approaches provide reasonably accurate results, though not as accurate as when actual heating value or density is known.

### 1.C.2.4 Inference

Mass balance estimates are irrelevant to emissions of methane and nitrous oxide (as well as criteria pollutants). Emissions estimates must necessarily either be made directly, from observed

emissions, or indirectly by inference from prior direct observation, either of the unit in question, or of some other comparable unit.

The EPA and the Intergovernmental Panel on Climate Change (IPCC) have published a set of coefficients for methane and nitrous oxide emissions from various classes of stationary source combustion devices. Those emission coefficients are based on a relatively small set of sample tests that are used to infer an "average" or "typical" emission factor, expressed as emissions per unit of fuel input or power output. The default emission factors are not necessarily the most accurate measures of actual methane and nitrous oxide emissions because these emissions are not closely linked to fuel input or power output. They are probably more closely linked to fuel-air ratios and completeness of combustion generally (for methane) and fuel-air ratios and peak combustion temperatures (for nitrous oxide). Available research shows that actual emissions of methane and nitrous oxide from stationary source combustion of fossil fuels are likely to be extremely small, even if the exact number is unknown.

## 1.C.3 Common Sources: Carbon Dioxide

### 1.C.3.1 Coal

Coal is used in the United States primarily for the generation of electric power and is typically combusted in large (greater than 100 MW) steam turbine electrical generating plants. Virtually all such units have continuous emissions monitors providing carbon dioxide emissions data to the EPA under Title IV of the CAAA.[13] These plants are typically "pulverized coal" units, in which coal is ground to a powder and sprayed into the combustion chamber, ensuring nearly complete combustion.

There are also significantly smaller and older "spreader stoker" units in which lump coal is mechanically introduced into the combustion chamber, and there perhaps remain a few units in which a person ("stoker") physically shovels coal into a furnace. These units are less likely to have continuous emissions monitors installed, and are more likely to be smaller scale units that provide space heating for building or campuses.

Coal-fired residential furnaces and stoves were once commonplace in the United States, but have been largely replaced in recent decades. The units that remain typically burn small quantities of high-grade anthracite coal, prized for its smokeless properties.

Carbon dioxide emissions data provided to the EPA under the CAAA are rated "A." (For a description of the emissions rating system and its uses, please see Part A of this Chapter.)

Carbon dioxide emissions estimates using mass balance may also be used, although the rating of such estimates will depend on the quality of the information used to estimate the emissions. Emissions estimates from large coal-fired units using mass balance may also be rated "A," provided the mass balance estimate has all of the following features:

[13] All coal-fired units with a capacity greater than 25 MW and all new coal-fired units burning fuels with a sulfur content greater than 0.5 percent are required to install CEMs.

- Fuel consumption is calculated by measuring fuel fed to the boiler rather than by fuel purchases or deliveries (this ensures that stock change is not counted as combustion).

- A plant-specific emission factor is calculated based on a periodic (at least monthly) analysis of coal samples as fed to the boiler, including analysis of both heating value and carbon content.

- The calculation takes into account carbon not oxidized into the atmosphere.

- The calculation takes into account non-combustion related carbon dioxide emissions arising from sorbent reactions in flue gas desulfurization units (if applicable).

Some large coal-fired units may not have EPA-regulated continuous emissions monitors. (For example, the units might be located outside the United States). Reporters may use data from non-EPA rated continuous emissions monitors if the data are reported to another Governmental authority for regulatory purposes. Those submissions would also be rated "A."

Table 1.C.2 illustrates ratings achievable for coal-fired units using mass balance calculations.

### Table 1.C.2. Quality Ratings for Estimation of Emissions for Coal-Fired Plants

| Plant Type | Emission Factor | | |
|---|---|---|---|
| | Plant-specific, periodic analyses | Plant-specific, single analysis | Default based on coal rank |
| CEM or mass balance supervised by a regulatory agency | A | NA | NA |
| Mass balance, measured consumption | A | B | C |
| Estimated consumption based on purchases or deliveries | B | C | D |

Table 1.C.3 provides default emission factors for U.S. coals assuming 99 percent combustion.

### Table 1.C.3. Emission Factors for U.S. Coal Consumption Assuming 99 Percent Combustion

| Coal Type | Emission Factor $kgCO_2/10^6$ Btu (HHV) | |
|---|---|---|
| | $CO_2$ | Carbon |
| Consuming Sector | | |
| Electric Power | 94.31 | 25.72 |
| Industrial Coking | 93.04 | 25.37 |
| Other Industrial | 93.44 | 25.48 |
| Residential/Commercial | 94.53 | 25.78 |
| **Coal Rank** | | |
| Anthracite | 102.58 | 27.98 |
| Bituminous | 92.53 | 25.24 |
| Sub-bituminous | 96.12 | 26.22 |

| | | |
|---|---|---|
| Lignite | 95.47 | 26.04 |

Source: Energy Information Administration, Documentation for Emissions of Greenhouse Gases in the United States 2003, May 2005, Table 6-2, p. 190, web site: www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf.

The factors shown in Table 1.C.3 were developed using a sample of U.S. coals. Coals burned abroad, and particularly coals produced and consumed within developing countries, may have somewhat different characteristics. Those coals may contain additional non-hydrocarbon materials and hence have a lower heating value (and lower carbon emissions) per ton of coal burned than in the United States, and reported heating values may exceed actual heating values. Similarly, "waste coal" burned in the United States may have idiosyncratic characteristics, and reporters using waste coal or reporting emissions from abroad should make specific efforts to obtain emission factors derived from analysis of the actual coal being burned rather than using default emission factors.

The emission factors provided in Table 1.C.3 further assume that the fraction combusted of coal consumed in the U.S. is 99 percent. If the reporter is not using a default emission factor but instead has specific information on the carbon content of the coal combusted, the 99 percent default fraction combusted may be assumed. If the reporter also has specific information on the amount of carbon left uncombusted (for example, by measuring carbon content in ash) this specific information should be used.

### 1.C.3.2 Natural Gas

Pipeline-quality natural gas is usually a homogenous product, typically sold by volume with a price adjustment for energy content. Most buyers will be aware of the volume and energy content of their purchases, and because storage of natural gas is difficult, gas purchases will usually equal gas consumption.

There are large variations in the composition of raw natural gas as produced from the field. However, processing by gas treatment plants to remove liquids and impurities, and the homogenizing effect of blending multiple gas streams into the pipeline system, tend to make natural gas sold to the end user a much more consistent product. For emissions estimation purposes, most of the variation in composition can be accounted for by estimating emissions based on energy content, rather than volume at standard temperature and pressure.

Natural gas combustion scales from household water heaters and furnaces to giant gas turbine power generation installations. Natural gas is also widely used in the industrial sector, in such analytically complex undertakings as cogeneration and chemical feedstock use. Cogeneration accounting is discussed in Part F.

As with other fuels, estimates from continuous emissions monitors that report carbon dioxide emissions under the supervision of a regulatory agency are rated "A." Emissions estimated using measured natural gas purchases or consumption volumes and actual or contractual heating content, together with default carbon dioxide emission factors, are also rated "A" because there is such little variation in the composition of pipeline-quality natural gas fuels. Mass balance emissions using measured natural gas volumes, but with assumed or default heating values, is

rated "B." Note that residential and commercial natural gas bills usually provide the heating value of the gas sold.

Natural gas with extremely high or low heating values probably also has an idiosyncratic chemical composition. Heating values greater than 1,100 Btu per standard cubic foot (scf)[14] imply high levels of heavier hydrocarbons such as propane or butane. Lower heating values imply high levels of inert gases such as nitrogen or carbon dioxide. Reporters using natural gas with a Btu content lower than 975 Btu per scf, or higher than 1,100 Btu per scf, should avoid using a default emission factor. To achieve an "A" rating for a mass balance estimate for gas falling outside this range, the reporter should estimate emissions using an emission factor based on an actual gas composition analysis (see Table 1.C.4). A gas composition analysis is a listing of the major component gases in a particular sample of natural gas, measured by molar volume. Gas composition analyses might be done to determine heating value, carbon content, or to verify compliance with contractual composition.

### Table 1.C.4. Rating of Estimation Methods for Carbon Dioxide Emissions from Natural Gas Combustion

| Estimation Method | Rating |
|---|---|
| Continuous emissions monitoring or mass balance supervised by a regulatory agency | A |
| Mass balance where heating value is known and falls between 975 and 1100 Btu per standard cubic foot. | A |
| Mass balance where heating value and gas composition are known and used to calculate a situation-specific emission factor (even if outside 975-1100 Btu/scf range) | A |
| Mass balance based on purchases where only volume is known (no heating value) | B |
| Mass balance of "rich" flare gas, or low-Btu gas, where composition is not known | C |

Table 1.C.5 provides default emission coefficients for pipeline quality natural gas in the United States.

### Table 1.C.5. Carbon Dioxide Emission Coefficients for U.S. Natural Gas assuming 99.5 Percent Combusted

| HHV Btu Content per Standard Cubic Foot | Emission Factor (metric tons carbon per billion Btu) | |
|---|---|---|
| | $CO_2$ | Carbon |
| 975 – 1,000 | 53.74 | 14.66 |
| 1,000 – 1,025 | 52.65 | 14.36 |
| 1,025 – 1,050 | 52.79 | 14.40 |
| 1,050 – 1,075 | 52.93 | 14.51 |
| 1,075 – 1,100 | 53.18 | 14.50 |

**Source**: Energy Information Administration, Documentation for Emissions of Greenhouse Gases in the United States 2003, May 2005, Table 6-5, p. 194, web site: www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf.

Natural gas is normally combusted completely in most of its applications. A default of 99.5 percent combustion is used for the emission factors in Table 1.C.5 and should be used in conjunction with reporter-developed estimates of carbon content in natural gas consumed, unless the reporter has information that would indicate a different level.

[14] A "standard cubic foot" is a cubic foot measured under "standard" conditions: atmospheric pressure, 60 degrees F.

### 1.C.3.3 Middle Distillates and Heavy Fuel Oil

"Middle distillates" is a term used by oil refiners to mean refined petroleum products that lie between gasoline and fuel oil. Distillates are nearly pure hydrocarbons, with extremely low levels of impurities such as sulfur or nitrogen. The most common distillate products are:

- Diesel fuel (including variants such as railroad, high speed, and marine diesel).
- No. 1 and No. 2 fuel oil (similar to diesel fuel, but not taxed in the United States).
- Kerosene-based jet fuel in civilian (Jet A) and military (JP-8) variants.
- Household kerosene, used for lighting and space heating.
- Undifferentiated middle distillates used as petrochemical feedstocks.

Over the past thirty years, distillates have usually been significantly more expensive than natural gas. This has resulted in the use of distillates for stationary source combustion being concentrated primarily in remote, rural, or temporary locations, or in holdovers from the era of cheap petroleum in the 1960s. Nonetheless, numerous examples remain of stationary source combustion using distillate fuel in the United States, both large and small. Some of the more prominent examples are:

- Residential and commercial space heating using heating oil.
- Stationary diesel engines driving electrical generators or providing motive power.
- Gas turbines for power generation (typically peaking power), compression, or motive power.

Heavy fuel oil, also called residual oil, has historically been the leftover heavy fraction of the crude oil barrel after the valuable light products, including the distillates, have been extracted. As such, fuel oil can have comparatively high sulfur contents—as much as 6 or 7 percent. In the United States, however, No. 5 and No. 6 fuel oil is typically a low sulfur semi-synthetic product that is no longer really a "residual." There can be considerable diversity in the actual density and carbon content of heavy fuel oil, therefore, particularly when comparing fuel oils used outside and within the United States.

Petroleum-burning installations are less likely to use continuous or other forms of emissions monitoring because of their relatively small size. Mass balance calculations will therefore usually be the only feasible method to estimate carbon dioxide emissions from those sources.

Most distillates and fuel oils are sold by volume (i.e., per gallon or barrel). Density, carbon content, and heating value do not normally form part of their formal definition, nor are those characteristics usually included as contractual elements in fuel purchase agreements. Hence, neither sellers nor buyers are likely to possess the information they need to calculate emissions based on the specific characteristics of the fuel. In lieu of this, reporters should use the standard characteristics shown in Table 1.C.6.

**Table 1.C.6. Emission Factors and Other Default Characteristics for Distillates and Fuel Oils Used In Stationary Source Combustion, Assuming 99 Percent Combusted**

| Fuel | Emission Factor (Metric Tons per $10^9$ HHV Btu) | | Gross Heat of Combustion (Btu per Barrel) | Density (Barrels per Metric Ton) | Percent Carbon (by weight) |
|---|---|---|---|---|---|
| | $CO_2$ | Carbon | | | |
| Middle Distillate Fuel (No. 1, No. 2, No. 4 fuel oil), diesel, home heating oil | 723.1542 | 19.795 | 5.825 | 7.44 | 86.34 |
| Jet Fuel (Jet A, JP-8) | 70.8716 | 19.3314 | 5.670 | 7.73 | 86.30 |
| Kerosene | 712.3159 | 19.572 | 5.670 | 7.71 | 86.01 |
| Heavy Fuel Oil (No. 5, 6 fuel oil), bunker fuel | 78.8001 | 21.4928 | 6.287 | 6.34 | 85.68 |

Source: Energy Information Administration, Documentation for Emissions of Greenhouse Gases in the United States 2003, May 2005, Table 6-6, p. 200, web site: www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf.

Table 1.C.7 lists the possible emission estimation approaches, in increasing order of desirability. (Most reporters will have only volumetric data).

**Table 1.C.7. Default Emissions Factor Methods for Distillate and Fuel Oil Stationary Source Combustion**

| Information Available | Method |
|---|---|
| Volume Only | Use assumed Btu content and emission factor from Table 1.C.6 |
| Actual weight or volume + actual density | Use or calculate weight of fuel, use default carbon content from Table 1.C.6, assume 99 percent combusted |
| Actual heating value (gross or net) | Use emission factor from Table 1.C.6 |
| Actual weight plus actual carbon content | Use actual weight multiplied by carbon content, assume 99 percent combusted |

### 1.C.3.4 Liquefied Petroleum Gases (LPG)

Unlike most hydrocarbon fuels, liquefied petroleum gases are nearly pure compounds, comprising ethane ($C_2H_6$), propane ($C_3H_8$), and butane ($C_4H_{10}$). Ethane is used widely as a petrochemical feedstock in the United States, with some secondary fuel use; propane is a common residential and commercial fuel for space heating use; and butane is used primarily as a petrochemical feedstock. Table 1.C.8 shows ratings for the various estimation methods.

**Table 1.C.8. Rating of Estimation Methods for Carbon Dioxide Emissions from Fuel Oil and Liquid Petroleum Gas Combustion**

| Estimation Method | Rating |
|---|---|
| Fuel Oil<br>Continuous emissions monitoring (CEM) or mass balance supervised by a regulatory agency | A |

| | |
|---|---|
| Mass balance based on actual* fuel consumption and specific information about fuel quality (e.g., heating value, density, or actual carbon content) | A |
| Mass balance based on actual* fuel consumption (or purchases if stock changes are not material**), with default emission factors | B |
| Mass balance based on fuel purchases (with no correction for stock change, if material**) and default emission factors | C |
| Liquid Petroleum Gas<br>Continuous emissions monitoring (CEM) | A |
| Mass balance using actual* quantities consumed (volume, weight, or heating value), the actual product is known and is propane or butane | A |
| Mass balance using actual quantities consumed (volume, weight, or heating value), the actual LPG product is not known. | B |
| Mass balance using fuel purchase data (with no correction for stock change, if material) | C |

*Actual quantities may be based on measured fuel use, fuel purchases corrected for stock changes, or uncorrected fuel purchase data where stock changes are not material. Changes in stocks equal to or greater than 5 percent of initial stocks are considered to be material.

**Changes in stocks equal to or greater than 5 percent of initial stocks are considered to be material.

In general, it is unlikely that LPG-burning stationary source combustion installations will have continuous emissions monitors. Consequently, emission estimation should be calculated through mass balance. The usual uncertainty about the actual density and composition of the fuel will not normally exist because LPGs are usually pure compounds, and default emission factors should be highly accurate. Table 1.C.9 below provides the default emission factors for the various LPG. If you are unable to determine the specific LPG used, apply the default emission factor for unspecified LPG.

### Table 1.C.9. Emission Factors for Liquefied Petroleum Gases Assuming 99 Percent Combusted

| Fuel | Emission Factor (metric tons/$10^9$ Btu) | | Gross Heat of Combustion (Btu per Barrel) | Density (Barrels per Metric Ton) | Percent Carbon (by weight) |
|---|---|---|---|---|---|
| | $CO_2$ | Carbon | | | |
| Ethane | 58.98 | 16.09 | 2,916 | 16.88 | 80.0 |
| Propane | 62.44 | 17.03 | 3,824 | 12.44 | 81.8 |
| Isobutene | 64.43 | 17.57 | 4,162 | 11.20 | 82.8 |
| n-butane | 64.32 | 17.54 | 4,328 | 10.79 | 82.8 |
| Unspecified LPG | 62.47 | 17.04 | NA | NA | NA |

**Source**: Energy Information Administration, Documentation for Emissions of Greenhouse Gases in the United States 2003, May 2005, Table 6-9, p.207, web site: www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf.

Carbon dioxide emissions estimates based on either mass, volume, or energy calculations are rated “A” if the actual quantities consumed are used, or if opportunities for storage are small (less then 10 percent of annual purchases). Emissions estimates are rated “B” if fuel purchase data are used and stocks are large (greater than 10 percent) relative to annual volume consumed.

## 1.C.4 Common Sources: Methane and Nitrous Oxide

Stationary source combustion units also emit trace amounts of methane and nitrous oxide. While such emissions are rarely measured accurately, available information suggests the amounts will usually be very small. Some possible emissions estimation methods are:

- Continuous emissions monitoring of methane and nitrous oxide. If there is an installed CEM that measures and reports methane or nitrous oxide emissions, this method would be rated "A" (such an installation would be highly unusual).[15]
- Unit-specific emission factors based on periodic or one-time exhaust sampling (e.g., from actual measurements) from the actual unit would be rated "A."
- Default emission factors based on consensus-based published sources (e.g., EIA's *Documentation for Emissions of Greenhouse Gases in the United States*, EPA's AP-42 or the IPCC Guidelines) are rated "B."
- Default emission factors based on other published sources are rated "C." See Table 1.C.11.

### Table 1.C.10. Ratings for Methane and Nitrous Oxide Emissions from Stationary Source Combustion

| Computation Method | Rating |
|---|---|
| Continuous Emissions Monitor | A |
| Unit-specific emission factors based on periodic, site-specific measurements | A |
| Unit-specific default emission factors from consensus-based single, site-specific measurement published sources | B |
| Default emission factors from consensus-based published sources | B |
| Default emission factors based on other published sources. | C |

There are three general sources for default emission factors for nitrous oxide and methane produced from fossil fuel combustion. The EPA's AP-42 handbook contains factors for a limited range of combustion technologies located throughout various chapters of the book.[16] EPA periodically updates the emission factors used in the AP-42 handbook as additional information becomes available. Reporters should consult the AP-42 handbook and use the most current emission factor available at the time of preparing their emissions estimate. The IPCC has two sets of methane and nitrous oxide emission factors, one more detailed and technology-specific, and one more generic. While more specific emission factors are typically preferred over more general emission factors, the rating for all three sources (AP-42 and the two IPCC factors) is "B The IPCC generic listing is provided in Table 1.C.11 below.

[15] In some cases it may be possible to extract methane emission estimates from monitoring non-methane volatile organic compounds (NMVOC) because the monitors may be tracking both total organic compounds and NMVOCs.

[16] Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors* (AP-42), Fifth Edition, Volume I: Stationary Point and Area Sources, pages 1.2-11 (6/96), 1.3-2.0 (9/98), 1.3-2.11 (7/00), 1.3-14 (9/98), 1-40 (9/98), 1.4-8 (7/98), 1.5-3 (6/96), 1.7-4.2 (9/98), and 3-1-12 (4/00).

**Table 1.C.11. IPCC Generic Methane and Nitrous Oxide Emission Factors for Stationary Fuel Combustion**

| Source | Methane (kg /$10^6$ Btu ) | Nitrous Oxide (kg per $10^6$ Btu) |
|---|---|---|
| Coal | | |
| Residential | 2.700 | 0.013 |
| Commercial | 0.090 | 0.013 |
| Industry | 0.090 | 0.013 |
| Electricity Generation | 0.009 | 0.013 |
| Petroleum | | |
| Residential | 0.090 | 0.005 |
| Commercial | 0.090 | 0.005 |
| Industry | 0.018 | 0.005 |
| Electricity Generation | 0.027 | 0.005 |
| Natural Gas | | |
| Residential | 0.043 | 0.000853 |
| Commercial | 0.043 | 0.000853 |
| Industry | 0.043 | 0.000853 |
| Electricity Generation | 0.008 | 0.000853 |
| Wood | | |
| Residential | 2.70 | 0.036 |
| Commercial | 2.70 | 0.036 |
| Industry | 0.27 | 0.036 |
| Electricity Generation | 0.27 | 0.036 |

**Source**: Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual* (Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories), p. 1-35Note: Converted from lower heating value metric units to higher heating value Btu by DOE.

## 1.C.5 Combustion from Special Situations

### 1.C.5.1 Refinery Gas

Refinery gas accounts for about 5 percent of U.S. oil consumption. Petroleum refiners boil or cook crude oil and other hydrocarbon feedstocks at very high temperatures. Under the impact of the heat, some of the hydrocarbon molecules disintegrate, releasing free hydrogen and hydrocarbon gases such as methane or ethane. Carbon monoxide and carbon dioxide may also be present. The blend will also contain smaller amounts of vapor from heavier hydrocarbons. The resulting gas is simultaneously a useful fuel, a potential feedstock, and an explosive safety hazard to be controlled.

Refineries are typically designed to recycle refinery gas as a heating fuel or (sometimes) a refinery feedstock. If processes generate refinery gas in excess of fuel and/or feedstock needs, refinery gas may be flared, or used to provide pilot lights for refinery flares. There are also a few cases where U.S. refinery gas is upgraded and exported as pipeline-quality natural gas to the interstate pipeline system.

The difficulties associated with estimating refinery gas emissions for inventory purposes are twofold:

- As an internal byproduct, refinery gas quantities are not always measured accurately, particularly if the gas is flared. Information about the volume of gas produced and its disposition may be held by plant operators and never appear in corporate accounting data.

- Even if the volume of refinery gas is known, its chemical composition is often highly variable because for large refineries the product is a blend of outgases in constantly varying quantities from a selection of refinery units. The average composition of refinery gas at a particular location will depend on which units and what feedstocks are being run at each particular moment in time. Refinery gas therefore includes varying quantities of high-carbon-per-Btu methane and no-carbon-per-Btu hydrogen.

Two default emission factors for refinery gas are available. The factor used by the Energy Information Administration (EIA) for its national emissions inventory is 17.51 metric tons carbon/billion Btu (higher heating value). It is based on an average of a small number of samples from the early 1990s.[17]

An alternative default factor has been proposed by the American Petroleum Institute's (API) Greenhouse Gas Compendium: 0.057 metric tons carbon dioxide per million Btu, equivalent to 15.45 metric tons carbon per billion Btu, citing "internal company information" as a source.[18] Note that API's coefficient is about 12 percent lower than EIA's coefficient (presumably because API's sample has more hydrogen and less carbon monoxide, ethane, and propane than EIA's small set of samples).

Reporters should use the EIA factor (17.42 metric tons carbon per billion Btu) as a default emission coefficient if no better information is available because its coefficient, which is for still gas, most closely approximates that gas mixture use as a feedstock (the principal constituents are methane, ethane, ethylene, normal butane, butylene, propane, and propylene). Reporters, however, should use available product-specific information, if reliable, in preference to a default factor. Ratings for various computation methods are provided in Table 1.C.12.

### Table 1.C.12. Ratings for Carbon Dioxide Emissions from Refinery Fuel Gas

| Information Available | Rating |
|---|---|
| Continuous emissions monitoring (or mass balance), supervised by a regulatory agency | A |
| Mass balance, based on volume, density and composition from multiple gas samples | A |
| Mass balance, based on volume plus density or heating value, and composition from a single gas sample | B |
| Mass balance, based on actual heating value, using default emission factor from consensus-based published sources | B |
| Mass balance, based on actual heating value, using other default emission factor | C |
| Mass balance, based on volume, using assumed heating value and default emission factor | D |

[17] Energy Information Administration, Documentation for Emission of Greenhouse Gases in the United States 2003 (May 2005), pp. 209-210, web site: www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf.
[18] American Petroleum Institute, Compendium of Greenhouse Gas Emission Estimation Methodologies for the Oil and Gas Industry (Final Draft, February 1, 2001), p. 4-8.

The default factors provided above assume 100 percent combustion. However, reporters should reduce these factors by the estimated fraction combusted, which should be assumed to be 98 percent for flaring and 99 percent for combustion as a boiler fuel. Reporters should note that both fuel use and flaring result in carbon dioxide emissions, and should make estimates that encompass both uses.

### 1.C.5.2 Petroleum Coke

Petroleum coke is a solid fuel composed of 90 percent or more carbon, and is usually created as a byproduct of the intensive refining of heavy oil feedstocks. It is similar to a high-grade coal, and EIA statistics describe it as catalyst coke and as marketable coke. Marketable coke is produced by oil refineries and sold as a commercial fuel or burned on-site as a fuel. Catalyst coke typically accumulates within oil processing units and is combusted in situ or removed and combusted.

Refiners may experience difficulty in estimating combustion usage of catalyst coke because it is not sold and may not be combusted for fuel purposes. A proper accounting for refinery sector emissions should, however, include accounting for all carbon oxidized into carbon dioxide from refinery sources, and this will necessarily include estimates of emissions from the combustion of catalyst coke. Ratings for coke emissions estimations are provided in Table 1.C.13.

**Table 1.C.13. Ratings for Carbon Dioxide Emissions from Petroleum Coke.**

| Information Available | Rating |
|---|---|
| Continuous emissions monitoring or mass balance supervised by a regulatory agency | A |
| Mass balance based on measured consumption or complete estimate of usage (including catalyst coke and non-fuel use, if applicable), actual carbon content composition of coke based on periodic samples | A |
| Mass balance based on measured consumption or complete estimate of usage (including catalyst coke and non-fuel use, if applicable), actual carbon content based on one-time sample | B |
| Mass balance based on measured consumption or complete estimate of usage, plus consensus-based default emission factor | B |
| Mass balance based on measured consumption or complete estimate of usage, plus other default emission factor | C |
| Mass balance based on marketable coke only (if catalyst coke is being combusted) and default emission factor | D |

Petroleum coke is used as a commercial fuel by refiners themselves, by electricity generators, and by cement producers in the United States. In these roles, petroleum coke should be treated in a manner analogous to coal, though using a petroleum coke emission coefficient.

Petroleum coke is also used as a carbon source in several industrial processes, notably as a sacrificial anode in aluminum smelting and a reducing agent in some metal refining processes. To the extent that the non-combustion use of petroleum coke results in the coke being oxidized, reporters should calculate emissions based on mass balance and the fraction combusted, even though technically the coke is not being used as fuel.

### 1.C.5.3 Flaring of Natural Gas or Crude Oil

Venting and flaring of commercial petroleum fuels is relatively uncommon but does occur, particularly in remote areas where natural gas cannot be marketed. Some of the more common circumstance under which flaring or venting may occur are:

- Flaring of waste or "off-spec" gas by gas processing plants.
- Safety flaring during process upsets in gas treatment, petroleum refining, or chemical plants; or as "pilot lights" on safety flares.
- Production testing on exploration wells (oil or gas).
- Flaring of unmarketable natural gas in remote areas.

Reporters should include any venting or flaring of natural gas and/or crude oil in their inventory. There are, however, certain complexities associated with estimating emissions from this source. Those include:

- Venting and flaring is not always measured, nor measured accurately. An "accurate" method for the purposes of this program is defined as a flow meter. Calculations based on reservoir balances, gas-oil ratios, or using lasers, are deemed "estimated."

- Venting natural gas implies methane emissions, which should be calculated by taking a compositional analysis of the raw natural gas and directly calculating methane (and carbon dioxide) emissions from the composition of the source gas.

- If the flare has relatively low combustion efficiency, the combustion implies methane emissions for the uncombusted portion of the flare.

Emissions from flare gas may be materially different than emissions of pipeline quality natural gas. Untreated raw "associated" natural gas produced in conjunction with crude oil will normally have high levels of propane and butane compared with pipeline gas. Raw natural gas will also occasionally have high levels of natural carbon dioxide (for instance, in parts of Texas and in Indonesia). In all cases, accurate estimates can be derived by calculating an emission factor based on the composition of a sample of the actual natural gas being flared.

Crude oil flaring is even more unusual than natural gas flaring, but does occur. In some parts of the world crude oil has also been used as a convenient oilfield boiler fuel (e.g., for steam floods). The most accurate emissions estimate in this case should be obtained by calculated carbon content from an ultimate analysis of the crude oil. If an ultimate analysis is not available, a tolerable proxy can be obtained when density and sulfur content are known, by assuming that carbon accounts for 85 percent of the non-sulfur portion of the crude oil (i.e., carbon content = (0.85 * (1-sulfur content)). If the reporter does not know density, a default emission factor can be obtained from EIA based on typical densities and heating values: 20.10 mtC (73.69 $mtCO_2$) per $10^6$ HHV Btu assuming 99 percent combustion.[19] Ratings for venting and flaring of natural gas emissions along with the rare cases when crude oil is combusted are shown in Table 1.C.14.

[19] Energy Information Administration, Documentation for Emission of Greenhouse Gases in the United States 2003 (May 2005), pp. 214-215, web site: www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf.

### Table 1.C.14. Carbon Dioxide Emissions Ratings for Venting and Flaring of Natural Gas and Combustion of Crude Oil

| Computation Method | Rating |
|---|---|
| **Venting and Flaring of Natural Gas**<br>Measured venting or flaring; actual composition data from periodic samples | A |
| Measured or estimated venting or flaring; actual composition data from single sample | B |
| Estimated venting or flaring; assumed composition using consensus-based published default emission factor | B |
| Estimated venting or flaring; assumed composition using other default emission factor | C |
| **Crude Oil Combustion**<br>Measured fuel use; emission factor based on actual composition data from periodic samples | A |
| Measured fuel use; assumed composition using consensus-based published default emission factor | B |
| Estimated fuel use; emission factor based on actual composition data from single sample | B |
| Estimated fuel use; assumed composition using default emission factor | C |

### 1.C.5.4 Petroleum-Based Waste and Byproduct Fuels

Reporters may also combust a range of specialized waste and byproduct fuels. Those might include:

- Used lubricants, especially motor oil.
- Used tires or tire-derived fuel.

These waste fuels are often burned in conjunction (co-fired) with more conventional fuels. If emissions are estimated based on continuous emissions monitoring, the monitor will measure carbon dioxide emissions from whatever combination of fuels is actually burned. In general, burning petroleum-based waste fuels raises no special issues.

If emissions are estimated based upon mass balance calculations, the reporter will need to have information about the quantity and composition of the fuels burned. Reporters are unlikely, though, to have specific information about the quality and composition of waste fuels, beyond a measure of the weight, volume, and hopefully the heating value of the fuel. In general, default emission factors will need to be used to cover these sources. See Table 1.C.15 below.

### Table 1.C.15. Emission Factors for Selected Petroleum-Based Waste Fuels

| Fuel | Density | Emission Factor |
|---|---|---|
| Waste Oil | ? | 9,979 kg $CO_2$/gallon |
| Tires/Tire-Derived Fuel | 12,000-15,000 Btu/Lb. | 85.8 metric tons $CO_2/10^6$ Btu |

Source: Energy Information Administration, Instructions for Form EIA-1605, Voluntary Reporting of Greenhouse Gases Program, Appendix B, web site: www.eia.doe.gov/oiaf/1605/coefficients.html.

Table 1.C.16 specifies the ratings used for petroleum-based waste and byproduct fuels.

**Table 1.C.16. Ratings for Carbon Dioxide Emissions from Selected Petroleum-Based Waste Fuels**

| Computation Method | Rating |
|---|---|
| Continuous emissions monitoring or mass balance supervised by a regulatory agency | A |
| Measured fuel use; emission factor based on actual composition data | A |
| Measured fuel use; assumed composition using default emission factor | B |
| Estimated fuel use; emission factor based on actual composition data | C |
| Estimated fuel use; assumed composition using default emission factor | D |

### 1.C.5.5 Biogenic Fuels (Bagasse, Wood, Wood Waste, and Ethanol)

Biogenic fuels are widely used, including wood burned in residences, wood pellets, wood waste and black liquor used in the pulp and paper industry, bagasse burned in sugar mills, wood shavings from lumber yards, and municipal greenwaste. All biogenic fuels contain a significant fraction of carbon, which is oxidized when burned. By accounting convention, though, carbon dioxide emissions of biogenic fuels do not "count" as anthropogenic emissions under the Framework Convention on Climate Change because the carbon embedded in biogenic fuels is presumed to form part of the natural carbon cycle. Carbon dioxide emissions from the combustion of biomass fuel, including discarded forest products, should not be included in either direct or indirect emissions and their quantity should not be included in combination with any other emissions category nor appear in totals or net quantities. Carbon dioxide emissions from the non-combustion oxidation of biomass, such as forest floor litter, biomass products, or discarded forest products such as mill shavings, are similarly considered carbon neutral.

Methane and nitrous oxide emissions from biogenic fuels are considered anthropogenic, however, and low- temperature combustion of biogenic fuels can produce large volumes of methane. Reporters combusting biogenic fuels should therefore consider methane and nitrous oxide emissions from this source.

Methane and nitrous oxide emissions are generally a product of low-temperature combustion. Methane is favored by conditions of incomplete combustion, where the organic compounds present in the fuel are broken down by heat into simple hydrocarbons, including methane, but there is insufficient heat or oxygen to combust them into carbon dioxide. This may be a good working description of a residential fireplace, but any process in which organic materials are burned may be considered a potential candidate for methane emission sources.

Reporters should use the same ratings for nitrous oxide and methane emissions from biogenic fuels as other fuels (shown on Table 1.C.10 above). In common with other sources of methane and nitrous oxide emissions, emissions derived from continuous monitoring of the exhaust stream or based on emission factors derived from periodic measurement of the actual source exhaust stream would be rated "A." Emissions estimated using a measurement or group of measurements of the actual exhaust stream would be rated "B." Emissions estimated using default emission factors would be rated "C."

Default emission factors may be derived from the EPA's AP-42 handbook or from the IPCC Revised Guidelines. Some typical factors drawn from the AP-42 handbook are shown in Table 1.C.17.

**Table 1.C.17. Methane and Nitrous Oxide Emission Factors for Biogenic Fuel Sources**

| Source | Methane | Nitrous Oxide |
|---|---|---|
| Wood residue (industrial) | 95.3 kg / $10^6$ Btu residue | NA |
| Conventional wood stove (non-catalytic) | 15 kg / metric ton wood | NA |
| Wood stove (non-catalytic) | 8 kg / metric ton wood | NA |
| Wood stove (catalytic) | 5.8 kg / metric ton wood | NA |
| Residential fireplace | NA | 0.15 kg /metric ton |
| Charcoal manufacture | 55 kg / metric ton charcoal | NA |

**Source**: Environmental Protection Agency, *Compilation of Air Pollutant Emission Factors* (AP-42), Fifth Edition, Volume I: Stationary Point and Area Sources.
NA=not available.

### 1.C.5.6 Municipal Solid Waste and Landfill Gas

Municipal solid waste is transmuted into an energy source by two mechanisms:

- It may be combusted directly (occasionally for disposal, more commonly as an energy source).
- When buried in a landfill, it may decompose anaerobically (in the absence of oxygen) into landfill gas (approximately 50 percent methane and 50 percent carbon dioxide and water vapor by volume), which may be emitted to the atmosphere, flared, or combusted as a commercial energy source.

The treatment of municipal solid waste intersects with the treatment of fuels from biogenic sources. From the point of view of emissions accounting, only combustible material that contains carbon produces carbon dioxide emissions. Only if this material is of anthropogenic origin (e.g., plastics) does its combustion produce reportable carbon dioxide emissions.

Reporters that combust municipal solid waste should thus examine estimates of the composition of their waste stream, identify the "anthropogenic carbon" (largely plastic and other synthetic materials) share of the waste stream, and derive an emission factor based on the anthropogenic carbon contained in each ton of municipal solid waste combusted. If the waste combustion plant is subject to emissions monitoring, the reported carbon dioxide emissions should be pro-rated by a calculated anthropogenic share of the carbon based on the calculation above.

If plant-specific estimates of the composition of the waste stream are not available, reporters may use a default emission coefficient developed by the EIA for use in the United States, based on earlier research by the EPA, which indicated that the U.S. national waste stream was 16 percent plastics, with an average emission coefficient of 5,771 lbs. carbon dioxide per short ton of plastic (2,885.5 kg/metric ton). This is equivalent to 919 lbs. $CO_2$ per short ton of municipal solid waste, or 92 lbs. $CO_2$ per million Btu (assuming a municipal solid waste energy content of 5,000 Btu per lb.)[20]

[20] See the EIA's voluntary reporting web site: www.eia.doe.gov/oiaf/1605/coefficients.html.

An emissions estimate using actual calculations from the waste stream linked to continuous emissions monitoring under the supervision of a regulatory agency would be rated "A." An emissions estimate using default calculations from the waste stream, but pro-rating CEM data, would be rated "B." An estimate using actual calculations from a measured waste stream, linked to the quantity of waste combusted, would also be rated "B." An estimate using the default emission factor multiplied by the quantity of waste combusted would be rated "C."

**Table 1.C.18. Ratings for Carbon Dioxide Emissions from Waste Fuels**

| Computation Method | Rating |
|---|---|
| Continuous emissions monitoring or mass balance supervised by a regulatory agency; pro-rated by measured waste composition. | A |
| Continuous emissions monitoring or mass balance supervised by a regulatory agency, pro-rated by default waste composition. | B |
| Consensus-based published default emission factor multiplied by quantity of waste combusted | B |
| Other default emission factor multiplied by quantity of waste combusted | C |

Non-combustion emissions of landfill gas and related issues are covered in Part E, "Industrial Processes."

## 1.C.6 Special Situations: Nonfuel Use of Fossil Fuels

There are a number of situations where fossil fuels are not combusted directly, but are used for an industrial purpose. Those uses include:

- Lubricants, asphalt, and petroleum-based solvents.
- Natural gas, LPG, and petroleum products as chemical feedstocks.
- Coke and related products as reducing agents in metals manufacture.
- Fossil fuels as a carbon source in products (e.g. carbon black).
- Transformation of lower value hydrocarbon into a higher value hydrocarbon (synthetic fuels).

While the treatment of specific industrial processes is largely the province of Part E, this section provides general guidance on the treatment of non-fuel uses of fossil fuels.

Generally it is the reporter's responsibility to identify all emissions of carbon dioxide that occur from facilities owned or controlled by the reporter. When fossil fuels are used for nonfuel uses, the reporter should identify whether the nonfuel use is sequestering, non-sequestering, or partially sequestering. In a sequestering use, the carbon in the feedstock remains in the final product or a waste stream, and is sold or transferred by the reporter to another entity. In non-sequestering use, the carbon in the final product is oxidized and moves into the atmosphere. In a partially sequestering use, some carbon is emitted to the atmosphere as carbon dioxide, while a portion remains embedded in the product.

Most plastics manufacturing (e.g., ethane to ethylene to polyethylene) appears to be largely sequestering. The carbon in the feedstock is embedded in the product and is transferred by the chemical manufacturer to another entity. Alternatively, certain forms of chemical manufacturing

(e.g., ammonia and hydrogen production) are non-sequestering; i.e., a feedstock (usually methane) is reformed into a carbon monoxide and hydrogen synthesis gas. The hydrogen is separated from the carbon monoxide and further processed (into ammonia, for instance), while the carbon monoxide is oxidized into carbon dioxide and usually discarded.

The use of coal or coke as a reduction agent is similarly non-sequestering. The coke is combusted under oxygen-deficient conditions to generate carbon monoxide, which is then used to scrub oxygen from metal ores. The resulting carbon dioxide is emitted to the atmosphere.

Some processes are partially sequestering. The manufacture of carbon black, for example, produces appreciable amounts of product composed largely of mineral carbon, but also produces significant emissions of carbon dioxide and carbon monoxide.

In each case it is the reporter's responsibility to understand the mass balance of his or her industrial process, to determine the quantity of carbon flowing through the reporter's entity, and ascertain how much carbon was emitted into the atmosphere and how much was transferred in product or in waste streams. Carbon emitted to the atmosphere is generally a reportable emission, while carbon that is transferred in product or in a waste stream is not reportable.
A computation of the carbon flows through an industrial process is also called a "material balance" calculation. A material balance calculation requires measuring or estimating the quantity of feedstock used in an industrial process, the quantity of product manufactured, and the quantity of materials discarded into waste streams, including atmospheric emissions. This particular application of material balance requires calculating the amount of carbon in the input feedstock, and tracing the fate of that carbon as it flows into manufactured product and waste streams. The material balance is an accounting of the sources and disposition of carbon, which in principle should be equal.

To accurately calculate a material balance, the reporter must know how much carbon is in the feedstock, how much carbon is in the manufactured product, and what happens to the remaining amount, possibly through stoichimetric calculations. A simpler procedure is to take the quantity of feedstock purchased and multiply it by a default emission factor and a default fraction not sequestered. This procedure is appropriate for specialized processes where computing a material balance is meaningless (e.g., use of asphalt, lubricants, or solvents), or where the source is too small to make detailed material balance calculations worthwhile.

Generalized emission measurement ratings for non-fuel use of petroleum products are shown below in Table 1.C.19.

### Table 1C.19. Ratings for Carbon Dioxide Emissions from Non-Fuel Use of Fossil Fuel

| Computation Method | Rating |
|---|---|
| Facility-level mass balance computation with known product composition | A |
| Facility-level mass balance computation with default emission factor for product | B |
| Product consumption multiplied by default emission factor multiplied by a default fraction combustion for asphalt, lubricants, and solvents | B |
| Product consumption multiplied by default emission factor multiplied by default fraction sequestered (petrochemical feedstocks). | C |

# Part D: Mobile Sources

Outline

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# Technical Guidelines Chapter 1, Part D: Mobile Sources

## 1.D.1 Overview

This part of Chapter 1 describes and rates methods of estimating emissions of greenhouse gases from mobile sources, such as automobiles, tractors, locomotives, watercraft, and aircraft. Mobile source greenhouse gas emissions include carbon dioxide ($CO_2$), methane ($CH_4$), and nitrous oxide ($N_2O$) from fuel combustion, and hydrofluorocarbons (HFC) from mobile air conditioning and refrigeration system leakage. Generally, reporters can expect carbon dioxide to be the largest portion of global warming potential (GWP)-weighted emissions from mobile sources. Methane and nitrous oxide emissions account for a relatively small fraction of overall mobile source greenhouse gas emissions: approximately one to two percent combined for mobile sources other than highway vehicles, and approximately five percent for light-duty, on-road vehicles (e.g., passenger cars and light trucks).[21]

There are a range of special situations that are unlikely to be of importance to reporters generally, but may be significant for particular reporters. These include electric, fuel cell, and bio-fueled vehicles, and they are discussed at the end of Part D.

Carbon dioxide emissions from the combustion of commercial fossil fuels may be accurately measured by mass balance when properly applied. Emissions of methane and nitrous oxide from combustion are difficult to measure accurately, but established estimation methods, such as the use of default emissions factors with vehicle distance traveled data, are available to reporters. For hydrofluorocarbons, reporters estimate emissions using inventories of refrigerant at installation, service, and disposal of air conditioning and refrigeration systems.

## 1.D.2 Estimation Methods

### 1.D.2.1 Overview

Most mobile source emissions originate from combustion of commercial fossil fuels, such as diesel fuel, gasoline, jet fuel, and residual fuel oils. Carbon dioxide emissions depend primarily on the carbon content of the fuel and the amount of fuel consumed. Methane and nitrous oxide emissions are generally a function of the emissions control equipment used (e.g., type of catalytic converter), and are also affected by the efficiency and design of the combustion technology and the level of operation and maintenance. More specifically, methane emissions from motor vehicles are a function of the amount of hydrocarbons passing uncombusted through the engine, and any post-combustion control of hydrocarbon emissions, such as catalytic converters.[22]

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[21] U.S. Environmental Protection Agency, Office of Atmospheric Programs, Climate Protection Partnerships Division, Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance, *Direct Emissions from Mobile Combustion Sources,* October 2004, web site: www.epa.gov/climateleaders/docs/mobilesourceguidance.pdf

[22] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2003* (April 15, 2005), web site: yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html.

Nitrous oxide is specifically produced during the reaction of nitrogen oxide (NO) and ammonia ($NH_3$) over the platinum in the catalytic converter, and therefore nitrous oxide emissions are generally greater from vehicles with catalytic converter systems than from vehicles without such controls, and greater from aged catalysts than from new catalysts.[23] Due to these complex interactions, there is greater uncertainty associated with estimates of methane and nitrous oxide emissions from mobile combustion sources relative to carbon dioxide emissions estimates.[24]

In addition to emissions from combustion of fuels, mobile sources equipped with air conditioning or refrigeration systems also release hydrofluorocarbons through leaks in the equipment. These gases may also be released during installation, maintenance, and disposal of the systems. As noted, release of hydrofluorocarbons from individual vehicles may be small, but considering that their GWPs are hundreds or even thousands of times greater than that of other mobile source greenhouse gases, the effects of total hydrofluorocarbon emissions are potentially significant.

For mobile sources, the mass balance method is most frequently used for estimating carbon dioxide and hydrofluorocarbon emissions based on fuel combustion and refrigerant use, respectively. Methane and nitrous oxide emissions are commonly estimated by inference using activity data (e.g., distance traveled or fuel consumption) with emissions factors developed from sample emissions measurement. For estimating carbon dioxide, mass balance can produce accurate results if calculations are based on known fuel properties such as weight and carbon content. Inferred emissions can generally be expected to be less accurate, but are acceptable for estimating minor emissions from methane and nitrous oxide. For leakage, the mass balance method or inference may be used to estimate hydrofluorocarbon emissions.

### 1.D.2.2 Mass Balance

The mass balance method is based on the premise that the mass and energy content of all components of a substance that go into a process must be chemically accounted for in some form as output. Estimating emissions using the mass balance method requires knowledge of the specific chemical reaction and data on the quantity of raw materials used or product manufactured. This information is used to estimate the mass of materials from at least one part of the overall chemical reaction. Emissions can then be calculated using the known molecular proportions (stoichiometric ratios) of the reaction formula.

Carbon dioxide emissions can usually be computed to an accuracy of 5 percent or better by using the following general formula for mass balance:[25]

$$C = QF * CC * FC$$

[23] U.S. Energy Information Administration, *Emissions of Greenhouse Gases in the United States, 2001*. December 2002, p. 52, web site: www.eia.doe.gov/oiaf/1605/1605aold.html.
[24] U.S. Environmental Protection Agency, Office of Atmospheric Programs, Climate Protection Partnerships Division, Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance, *Direct Emissions from Mobile Combustion Sources*, October 2004, web site: www.epa.gov/climateleaders/docs/mobilesourceguidance.pdf.
[25] Intergovernmental Panel on Climate Change, *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*, June 2001, web site: www.ipcc-nggip.iges.or.jp/public/gp/english/.

**Where:**

**C = carbon dioxide emissions (metric tons)**
**QF = quantity of fuel (measured in weight, volume, or heating value)**
**CC = carbon coefficient (a ratio, metric tons carbon dioxide per "unit" of fuel, as above)**
**FC = fraction combusted**

Fuel quantity may be expressed in terms of weight (tons or pounds of fuel); volume (barrels or gallons or cubic feet or cubic meters of fuel); or heating value (million Btu or joules, either higher heating value or lower heating value).[26] The carbon coefficient of the fuel is the theoretical maximum carbon dioxide emission rate for a fuel expressed in terms of units of carbon dioxide per unit of fuel denominated by any of these measures. If the carbon content of the fuel is known, its carbon coefficient can be calculated by assuming 100 percent of the carbon is converted to carbon dioxide during combustion. As recommended by the Intergovernmental Panel on Climate Change (IPCC), reporters should use 99 percent as the factor for the fraction combusted for all petroleum-based transportation fuels. For natural gas or other gaseous fuels, reporters should use 99.5 percent as the factor for the fraction combusted.[27]

The default carbon dioxide emissions factors provided in this chapter reflect the default carbon coefficients for the referenced fuel multiplied by the IPCC recommended fraction combusted. Because reporters will most often have data on consumption of liquid fuels in units of volume, default emissions factors are presented below per unit of heat content and per unit of volume.

In general, reporters should use the measure of fuel quantity that most accurately represents the characteristics of the fuel consumed and should minimize the use of default values by substituting parameters based on measurements whenever possible.

When the actual carbon content of the fuel is known (based on a fuel sample analysis), the most accurate calculation of mass balance emissions is based on weight. If the reporter does not know the carbon content of the fuel, but does know the heating value (this would be typical of natural gas and some fuel oils), the most accurate mass balance calculation would be based on heating value and a default emissions factor.

Reporters will rarely have access, however, to detailed information about the composition of transportation fuels. Transportation fuels are predominantly composed of liquid fuels, which are generally sold by volume, and are defined by specifications that do not normally address heating value, carbon content, or density. Further, because transportation fuels will often be purchased by the fuel tank-full in diverse locations, a fuel-testing program will rarely be practicable. For those reasons, the most accurate approach that is practically achievable will usually be to multiply fuel volume by an assumed density and carbon content per ton, or alternatively, to multiply fuel volume by an assumed heating value per unit volume and an emissions factor

[26] Reporters should use higher heating values, which are commonly used in the United States. Internationally, however, the "lower" heating value is used. For more information, see Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*, Vol. 3 (Paris, France, 1997), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.
[27] Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual* (1997), Table 1-6, www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

expressed per unit of heating value. Both approaches provide reasonably accurate results, though not as accurate as when actual heating value or density is known.

Fugitive emissions are most easily measured when a known quantity of gas is purchased to replace losses that have occurred over a given time period. Purchasing refrigerant to re-fill a refrigerating unit is an example of this situation. In these cases, fugitive emissions are equal to new purchases/inputs minus the volume of gas required to satisfy net growth in the equipment stock (net growth equals the difference between the volumes of new and retiring equipment). This type of estimation falls under the category of mass balance, because it tracks specific quantities of materials included in a process.

### 1.D.2.3 Inference

The inference method is the use of emissions factors derived from sample data of prior observations that are assumed to be representative of certain conditions that will be experienced by other reporters. Because mass balance estimates are irrelevant to emissions of methane and nitrous oxide (as well as criteria pollutants), emissions estimates must either be made directly, from observed emissions, or indirectly by inference from prior direct observation, either of the unit in question, or of some comparable unit. Nitrous oxide and methane emissions depend largely on combustion technology type and vintage, emission control technology, maintenance, and operational practices. Emissions of those gases are only generally related to fuel consumption or vehicle distance traveled.

Unfortunately, there is insufficient information to establish a useful relationship between many of the specifics of vehicle characteristics or operating cycles and emissions. Even if such information existed, reporters would find difficulty in obtaining this information about their vehicle fleets. Fortunately, available information suggests that nitrous oxide and methane emissions from mobile sources will normally be small.

Estimates should be based on vehicle distance traveled data and emissions factors for the specific vehicle types and technology, whenever possible. If vehicle distance traveled data is unavailable, fuel consumption data together with fuel economy factors can be used to back-calculate vehicle distance traveled. Information on specific emission control technologies, such as catalytic converters, may be inferred from weighted averages of control technologies by vehicle model year.

The IPCC, World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD), U.S. Environmental Protection Agency (EPA), Energy Information Administration (EIA), American Petroleum Institute (API), and other authorities on greenhouse gas estimation methods provide inference-based methods to estimate emissions associated with methane and nitrous oxide emissions from mobile sources. These equations use activity-level data and an associated emissions factor, according to the following general formula:

$$E = AL * EF$$

**Where:**

**E = Emission**
**AL = Activity Level**
**EF = Emissions Factor.**

The EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* contains U.S. transportation sector-specific emissions factors.[28] Emissions factors are provided by type of highway vehicles (e.g., passenger cars, light and heavy duty trucks, motorcycles, etc.) and control technology (e.g., specific types of catalytic converters and without catalytic converters). Because data on specific vehicle fleet technologies may not be available, a more generalized set of emissions factors using a weighted average of control technologies by vehicle model year also is available.[29]

Methane and nitrous oxide emissions from mobile sources have not been extensively studied and the emissions factors are based on a limited number of studies. The studies have been used to infer an "average" or "typical" emissions factor, expressed in terms of grams per vehicle distance traveled, or per unit of fuel consumed. Because of the large number of emissions factor tables that represent all of the vehicles and technology combinations, not all emissions factors are reproduced in this document. A subset of factors does appear below in Table 1.D.2 in subsection 1.D.3.2.1. Please refer to the EPA inventory for factors specific to the United States. EIA, in its publication *Documentation for Emissions of Greenhouse Gases in the United States 2003*, also provides step-by-step emission estimation techniques, based on IPCC and EPA emissions factors, for both mobile source nitrous oxide and methane emissions.[30] The IPCC also provides additional guidance, and factors for other countries.[31,32] Other bodies, such as the EPA voluntary programs,[33] the WRI/WBCSD,[34] and API,[35] provide additional guidance and reporters are encouraged to review those guidance documents when preparing their inventories.

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[28] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2003*, Annex 3.2, April 2005, web site: yosemite.epa.gov/OAR/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html.

[29] U.S. Environmental Protection Agency, Office of Atmospheric Programs, Climate Protection Partnerships Division, Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance, *Direct Emissions from Mobile Combustion Sources* (October 2004), web site: www.epa.gov/climateleaders/docs/mobilesourceguidance.pdf.

[30] Energy Information Administration, *Documentation for Emissions of Greenhouse Gases in the United States 2003* (May 2005), web site: www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf.

[31] Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual* (Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

[32] Intergovernmental Panel on Climate Change, *Good Proactive Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (June 2001), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*.

[33] See www.epa.gov/climateleaders.

[34] World Business Council for Sustainable Development and World Resources Institute, *The Greenhouse Gas Protocol*, September 2001, web site: www.ghgprotocol.org/plugins/GHGDOC/details.asp?type=DocDet&ObjectId=MTM3NTc.

[35] American Petroleum Institute (API), *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* (February, 2004), web site: api-ec.api.org/filelibrary/2004_COMPENDIUM.pdf.

## 1.D.3 Application and Ranking of Methods

### 1.D.3.1 Carbon Dioxide from Mobile Combustion Systems

In mobile systems, carbon dioxide is generated by combustion systems burning carbon-containing fuels such as motor gasoline, diesel fuel, residual fuel oil, or jet fuel. All mobile sources that have combustion systems generate carbon dioxide. Reporters that are estimating emissions from mobile combustion systems that burn fossil fuels should include all of the carbon dioxide in their emission inventories. Reporters that operate vehicles using pure biofuels such as ethanol and biodiesel within their entity should not add the carbon dioxide emissions from those fuels to their inventory of mobile source emissions. If biofuel blends (e.g., E85, a blend of 85 percent ethanol and 15 percent gasoline, or B20, a blend of 20 percent biodiesel and 80 percent petroleum-based diesel) are used, only the carbon dioxide associated with the hydrocarbon portion should be reported, and the biogenic carbon should not be added to the emissions inventory (refer to 1.D.4, "Special Situations," below). If reporters operate electric vehicles, the associated carbon dioxide emissions should be estimated using guidance from Part F, "Indirect Emissions." Reporters operating hybrid gas-electric vehicles need only report emissions from the combustion of motor gasoline, because the electricity used is generated within the vehicle and not obtained from the grid.

#### 1.D.3.1.1 Highway Vehicles

This category includes a variety of on-road light- and heavy-duty vehicles consuming a number of different fuels. Within this category, on-road light- and heavy-duty vehicles using conventional fuels (gasoline or diesel) include: passenger vehicles, hybrid-electric vehicles, motorcycles, light-duty trucks (vans, pick-up trucks and sport utility vehicles), medium-duty trucks, heavy-duty trucks, and buses. Also included in this category are on-road vehicles using alternative fuels (e.g., compressed natural gas, propane, methanol), which include passenger vehicles, light-duty trucks, heavy-duty trucks, and buses. Biofuel, electric, and fuel cell vehicles are not discussed in this subsection (refer to 1.D.4, "Special Situations," below, for that discussion).

As noted above, liquid fuel purchasers for highway vehicles will rarely know more about the gasoline and diesel fuel they consume than the volume purchased. In contrast to stationary combustion estimates, therefore, the best available emissions estimate will use a default emissions factor based upon the type and volume of fuel purchased, although there are issues associated with how fuel consumption is measured. The most accurate measurement of fuel consumption will usually take place at the point of purchase. In most cases, fuel will be purchased from a vendor and pumped directly into the tanks of the vehicle, but reporters should be alert to the possibility of unreported stock changes. This might occur, for example, when the reporter purchases fuel in bulk, stores the fuel, and then refuels fuel to vehicles as needed. In similar cases, reporters should modify actual consumption by fluctuations in the quantity of fuel in storage.

For highway vehicles, carbon dioxide estimates using the mass balance method are rated "A," provided that the volume of fuel burned is measured by metered quantities of fuel loaded into the

vehicle, or via bulk purchase data that account for stock changes. Use of measured density, heating value, or carbon content to estimate fuel characteristics more accurately is preferred, if possible. If reporters know the total heat content or volume of fuel consumed, they can use the default emissions factors provided in Table 1.D.1. Reporters should compare fuel consumption data with operating data (e.g., distance traveled or operating hours) and document that the reported fuel consumption data are reasonable.

### Table 1.D.1. Carbon Dioxide Emissions Factors for Transportation Fuels

| Transportation Fuel | Carbon Dioxide Emissions (Pounds/Unit Volume) | Carbon Dioxide Emissions (Metric Tons / Billion Btu) |
|---|---|---|
| Aviation Gasoline | 18.15 per gallon | 68.50 |
| Biodiesel/Biodiesel Blends[a] | | |
| - B100 | 0 | 0 |
| - B20 | 17.71 | 59.17 |
| - B10 | 19.93 | 65.86 |
| - B5 | 21.04 | 69.16 |
| - B2 | 21.70 | 71.12 |
| Diesel Fuel (No.1 and No.2) | 22.15 per gallon | 72.43 |
| Ethanol/Ethanol Blends[b] | | |
| - E100 | 0 | 0 |
| - E85 | 2.9 | 14.59 |
| - E10 (Gasohol) | 17.41 | 65.29 |
| Motor Gasoline | 19.36 per gallon | 70.21 |
| Jet Fuel, Kerosene | 20.88 per gallon | 70.17 |
| Natural Gas | 119.90 per 1000 cubic feet | 52.80 |
| Propane | 12.60 per gallon | 62.76 |
| Residual Fuel (No.5 and No.6 Fuel Oil) | 25.75 per gallon | 78.02 |

Source: Energy Information Administration, *Documentation for Emissions of Greenhouse Gases in the United States 2003*, (May 2005), p.189, web site: www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf.
[a] Emission factors for biodiesel blends were calculated using the net (lower) heating value for biodiesel from National Biodiesel Board web site: www.biodiesel.org/pdf_files/fuelfactsheets/BTU_Content_Final_Oct2005.pdf. The gross (higher) heating value was assumed to be 5% higher than the net heating value (see Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual, p. 1.5, web site: www.ipcc-nggip.iges.or.jp/public/gl/invs6.htm).
[b] Emission factors for ethanol blends were calculated using the higher heating value for ethanol from U.S. Department of Energy, Alternative Transportation Fuel Data Center, web site: www.eere.energy.gov/afdc/pdfs/fueltable.pdf.
Note: Fraction combusted is assumed to be 99 percent for liquid fuels and 99.5 percent for gaseous fuels.

Carbon dioxide emissions estimates based on multiplying default emissions factors by actual measured volumes from periodic bulk purchases, but without accounting for stock changes, are rated "B."

Carbon dioxide estimates using the mass balance method are rated "C" if the mass balance calculations are based on one of the following sets of data, which must be available to the reporter:

- Distance traveled activity data by vehicle type, and inferred or assumed vehicle fuel economy (both city and highway).

- Vehicle-specific distance traveled activity data, and inferred or assumed vehicle fuel economy (both city and highway).
- Hours, horsepower hours of operation, or ton-distance shipped and *specific* information on fuel consumed per unit of activity data from vehicle suppliers, manufacturers, or in-company records (e.g., may be common for diesel-fueled trucks).

Carbon dioxide estimates using the mass balance method are rated "D" if estimates are based on fuel price or expenditure data without corresponding data on quantities purchased, if average annual or monthly fuel prices are used to calculate fuel volume. Users of fuel expenditure data for emissions estimation should be alert for fuel purchase records being "contaminated" by purchases of unrelated non-fuel items from fuel vendors.

Users of electric vehicles should refer to Part F, "Indirect Emissions," for methods of calculating emissions from the consumption of electricity used to charge their vehicles.

#### 1.D.3.1.2 Off-Road Vehicles Including Diesel Locomotives

The off-road vehicle category includes a wide variety of vehicles operating on conventional fuels such as gasoline, diesel, and fuel oil. Vehicles within this category include construction equipment, agricultural equipment, off-road recreational vehicles, snowmobiles, and diesel locomotives. Most off-road vehicles will burn un-taxed (red-dyed) diesel fuel (off-highway No. 2-D), which is generally very similar to its taxed counterpart, while locomotives use a special railroad diesel. Conventional snowmobiles and some other recreational off-road vehicles have two-stroke spark-ignition engines that burn a gasoline-lubricant mixture, though some relatively new snowmobiles may operate using four-stroke spark-ignition engines that combust motor gasoline only.

Most railroad locomotives are powered by diesel engines, burning railroad diesel fuel, though some corridors (notably in the Northeast) are electrified, while subway and light rail (streetcar) systems are usually electric. While operators of diesel-fueled railroad vehicles should report emissions following the guidelines provided here for off-road vehicles, operators of electrified rail systems should refer to Part F, "Indirect Emissions," for methods of calculating emissions from the consumption of electricity used to charge their vehicles.

For off-road vehicles, carbon dioxide estimates using the mass balance method are rated "A," provided the mass balance estimates are based on actual fuel quantities consumed as measured by metered quantities of fuel loaded into the vehicle or by bulk purchase data that accounts for stock changes. Use of measured density, heating value, or carbon content to estimate fuel characteristics more accurately is preferred, if possible. Reporters should compare fuel consumption data with operating data (e.g., operating hours or distance traveled), and document that reported fuel consumption data are reasonable.

Carbon dioxide estimates using the mass balance method based only on bulk fuel purchase data not adjusted for stock changes, are rated "B."

Carbon dioxide estimates using the mass balance method are rated "C," provided the mass balance calculations are based on one of the following sets of data, which must be available to the reporter:

- Distance traveled data and fuel economy for each engine.
- Hours, horsepower hours of operation, or ton-distance shipped and *specific* information on fuel consumed per unit of activity data from vehicle suppliers, manufacturers, or in-company records.

Carbon dioxide estimates using the mass balance method are rated "D" if estimates are based on any of the following available data:

- Fuel price data only.
- Default factors for fuel consumption per unit of activity data.

#### 1.D.3.1.3 Water Borne Vessels

Water borne vessels include recreational boats, patrol boats, cruise ships, large freight vessels, container ships, and many other types of vessels with various purposes. In general, very small boats (often less than 50 feet in length) have spark ignition inboard, stern drive (inboard/outboard or inboard/outdrive), or outboard engines that burn gasoline. Some boats less than 50 feet in length may have inboard compression ignition (i.e., diesel-cycle) engines that burn diesel fuel or another distillate, residual fuel, or intermediate blend. Nearly all commercial shipping vessels and cruise ships have large diesel engines that burn residual fuel or an intermediate distillate-residual blend, but it is possible that some of these compression ignition engines burn a kerosene-based fuel. Some ships, especially high-speed ferries and military vessels, have gas turbine engines that burn kerosene-based jet fuel.

The propensity of merchant vessels to blend diesel and residual fuel raises special problems for estimating emissions accurately, although marine fuels are often sold by weight rather than by volume and the carbon content of residual fuel is frequently known.

For water borne vessels, carbon dioxide estimates using the mass balance method are rated "A," provided the mass balance estimates are based on actual fuel quantities consumed, or via bulk fuel purchase data that accounts for stock changes, and calculated using one of the following sets of data, which must be available to the reporter:

- Known weight and carbon content and default fraction combusted.
- Weight or volume and actual heating value of fuel, and default carbon dioxide emission factor from Table 1.D.1.
- Weight of fuel only and default carbon dioxide emission factor from Table 1.D.1.
- Volume and actual density of fuel and default carbon dioxide emission factor from Table 1.D.1.
- Specified fuel type and default carbon dioxide emissions factor (from Table 1.D.1, above).

Reporters should compare fuel consumption data with operating data (e.g., operating hours or distance traveled) and document that reported fuel consumption data are reasonable.

Carbon dioxide estimates using the mass balance method based only on bulk fuel purchase data not adjusted for stock changes are rated "B."

Carbon dioxide estimates using the mass balance method are rated "C," provided the estimates of fuel quantity are derived from one of the following sets of data, which must be available to the reporter:

- Distance traveled data and fuel economy for each engine.
- Hours, horsepower hours of operation, or ton-distance shipped and *specific* information on fuel consumed per unit of activity data from vehicle suppliers, manufacturers, or in-company records.

Carbon dioxide estimates using the mass balance method are rated "D" if estimates of fuel quantity are derived from any of the following available data:

- Fuel price data only.
- Default factors for fuel consumption per unit of activity data.

#### 1.D.3.1.4 Aircraft

This category includes all aircraft running on kerosene jet fuel and non-jet-engine planes that burn aviation gasoline, or less commonly, motor gasoline. The vehicle types include turbine- and piston-engine-driven aircraft, turbine-powered transport and air cargo aircraft. Within this category, reporters will consider all civil commercial uses of airplanes (international and domestic) consisting of scheduled and chartered flights for passengers and freight. Emissions from aircraft should be included in the entities inventory in the country in which the fuel was purchased. This category also includes civil commercial use of airplanes and helicopters for agricultural purposes, instructional flying, business and pleasure flying, aerial work, and any other flying.

As in other transportation instances, both aviation gasoline and jet fuel are sold by volume, without reference to weight or carbon content. Consequently, the most accurate available estimates of emissions will generally be based on the use of default emissions factors and estimates of fuel volume.

For aircraft, carbon dioxide estimates using the mass balance method are rated "A," provided that the volume of fuel burned is measured by metered quantities of fuel loaded into the vehicle, or via bulk purchase data that account for stock changes. Use of measured density, heating value, or carbon content to estimate fuel characteristics is preferred, if possible. Reporters should compare fuel consumption data with operating data (e.g., flight hours or operating hours) to document that reported fuel consumption data are reasonable.

Carbon dioxide estimates using the mass balance method based only on fuel consumption volume are rated "B" if the data reflect bulk fuel quantities that do not account for stock changes. Aviation entities may keep large fuel stocks on site, which could significantly influence annual emissions estimates when not reporting changes in stock.

Carbon dioxide estimates using the mass balance method are rated "C," provided the estimates of fuel quantity are derived from one of the following sets of data, which must be available to the reporter:

- Distance traveled data and fuel economy for each engine.
- Hours, horsepower hours of operation, or ton-distance shipped and *specific* information on fuel consumed per unit of activity data from vehicle suppliers, manufacturers, or in-company records.

Carbon dioxide estimates using the mass balance method are rated "D" if estimates of fuel quantity are derived from any of the following available data:

- Fuel price data only.
- Default factors for fuel consumption per unit of activity data.

### 1.D.3.2 Methane and Nitrous Oxide from Mobile Combustion Systems

#### 1.D.3.2.1 Highway Vehicles

For highway vehicles, estimates of methane and nitrous oxide emissions using the inference method based on vehicle distance traveled or fuel consumption and an emissions factor for specific vehicle types are rated "A," provided the combustion and emission control technology type are known for each vehicle.

Methane and nitrous oxide emission estimates using the inference method based on total vehicle distance traveled (for an uncharacterized vehicle mix) and an emissions factor that represents the weighted average of available control technologies by model year is rated "B." Those weighted averages are provided by the EPA Climate Leaders voluntary program.[36]

The methane and nitrous oxide emissions factors for U.S. highway vehicles developed by the EPA cover a number of vehicle types with various control technologies. The vehicle types include gasoline passenger cars, light-duty trucks, and heavy-duty vehicles; diesel passenger cars, light-duty trucks, and heavy-duty vehicles; and motorcycles. The control technology categories for gasoline vehicles include low emission vehicle technology, three-way catalyst controls (EPA Tier 1), early three-way catalysts (EPA Tier 0), oxidation catalysts, non-catalyst controls, and uncontrolled. The control technology categories for diesel vehicles are advanced, moderate, and uncontrolled, and the control technology categories for motorcycles are non-catalyst control and uncontrolled. EPA provides control technology assignments for vehicle types based on model year.[37] For example, all gasoline-fueled passenger cars of model years 1984-1993 have the control technology EPA Tier 0/Early Three-Way Catalyst.

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[36] U.S. Environmental Protection Agency, Office of Atmospheric Programs, Climate Protection Partnerships Division, Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance, *Direct Emissions from Mobile Combustion Sources* (October 2004), web site: www.epa.gov/climateleaders/docs/mobilesourceguidance.pdf.

[37] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2003,* Annex 3.2, April 2005, web site:

The IPCC provides a range of methane emissions factors for all highway vehicles and control technologies broken down into Spring/Fall, Summer, and Winter seasons. These factors also are averaged and expressed in terms of grams per kilometer, grams per kilogram fuel and grams per mega joule. Averaged single emissions factors are provided for nitrous oxide expressed in terms of grams per kilometer, grams per kilogram fuel and grams per mega joule.[38] In addition, EPA developed methane and nitrous oxide emissions factors using a weighted average of control technologies by vehicle model year for cases where data on specific control technologies are unavailable.[39] Expressed in terms of grams per mile, these emissions factors cover gasoline passenger cars, vans, pickup trucks, sport utility vehicles and heavy-duty vehicles for model years 1984-2003. For diesel passenger cars, light trucks, and heavy-duty vehicles, the emissions factors cover model years 1966-2001.[40] Table 1.D.2, below, presents suggested emissions factors for methane and nitrous oxide for highway vehicles, which can be used with control technology assignment data referenced above and defined in Table 1.D.3. If the specific control technology for the vehicle(s) is not known, reporters can use the emission coefficients for the predominant control technology for the model year of the vehicle(s) shown in Table 1D.4.

For alternative fuel vehicles, the EPA developed methane and nitrous oxide emissions factors covering light-duty vehicles, heavy-duty vehicles, and buses. For light-duty vehicles, emissions factors are provided for methanol, compressed natural gas, liquefied petroleum gas (propane) and ethanol fuel types. For heavy-duty vehicles, emissions factors are available for liquefied natural gas in addition to the fuel types listed for light-duty vehicles. For buses, emissions factors are available for methanol and compressed natural gas. The emissions factors are expressed in terms of grams per mile and grams per kilometer.[41]

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yosemite.epa.gov/OAR/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html.

[38] Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual* (Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm. The *IPCC Good Proactive Guidance and Uncertainty Management in National Greenhouse Gas Inventories* updates the nitrous oxide emissions factors for gasoline vehicles. See Table 2.7 on p. 2.47, web site: www.ipcc-nggip.iges.or.jp/public/gp/english/.

[39] U.S. Environmental Protection Agency, Office of Atmospheric Programs, Climate Protection Partnerships Division, Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance, *Direct Emissions from Mobile Combustion Sources* (October 2004), web site: www.epa.gov/climateleaders/docs/mobilesourceguidance.pdf.

[40] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001*, Annex E (September 23, 2003), EPA 430-R-03-004, pp. E-11 to E-13. All values were calculated from Tables E-9 through E-13, web site: http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/LHOD5MJTA3/$File/2003-final-inventory_annex_e.pdf.

[41] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001*, Table E-14 (September 23, 2003), Annex E, EPA 430-R-03-004, pg. E-13, web site: http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/LHOD5MJTA3/$File/2003-final-inventory_annex_e.pdf.

## Table 1.D.2: Emissions Factors for Methane and Nitrous Oxide for Highway Vehicles

| Vehicle Type/Control Technology | $N_2O$ (g/mi) | $CH_4$ (g/mi) | $N_2O$ (g/km) | $CH_4$ (g/km) |
|---|---|---|---|---|
| **Gasoline Passenger Cars** | | | | |
| Low Emission Vehicles | 0.0222 | 0.0169 | 0.0138 | 0.0105 |
| EPA Tier 1 | 0.0429 | 0.0271 | 0.0267 | 0.0168 |
| EPA Tier 0 | 0.0647 | 0.0704 | 0.0402 | 0.0437 |
| Oxidation Catalyst | 0.0504 | 0.1355 | 0.0313 | 0.0842 |
| Non-Catalyst | 0.0197 | 0.1696 | 0.0122 | 0.1054 |
| Uncontrolled | 0.0197 | 0.1780 | 0.0122 | 0.1106 |
| **Gasoline Light-Duty Trucks** | | | | |
| Low Emission Vehicles | 0.0146 | 0.0216 | 0.0091 | 0.134 |
| EPA Tier 1 | 0.0871 | 0.0452 | 0.0541 | 0.0281 |
| EPA Tier 0 | 0.1056 | 0.0776 | 0.0656 | 0.0482 |
| Oxidation Catalyst | 0.0639 | 0.1516 | 0.0397 | 0.0942 |
| Non-Catalyst | 0.0218 | 0.1908 | 0.0135 | 0.1186 |
| Uncontrolled | 0.0220 | 0.2024 | 0.0137 | 0.1258 |
| **Gasoline Heavy-Duty Vehicles** | | | | |
| Low Emission Vehicles | 0.0290 | 0.0434 | 0.0180 | 0.0270 |
| EPA Tier 1 | 0.1750 | 0.0655 | 0.1087 | 0.0407 |
| EPA Tier 0 | 0.2135 | 0.2630 | 0.1326 | 0.1634 |
| Oxidation Catalyst | 0.1317 | 0.2536 | 0.0818 | 0.1464 |
| Non-Catalyst Control | 0.0473 | 0.4181 | 0.0294 | 0.2598 |
| Uncontrolled | 0.0497 | 0.4604 | 0.0309 | 0.2861 |
| **Diesel Passenger Cars** | | | | |
| Advanced | 0.0010 | 0.0005 | 0.0006 | 0.0003 |
| Moderate | 0.0010 | 0.0005 | 0.0006 | 0.0003 |
| Uncontrolled | 0.0012 | 0.0006 | 0.0008 | 0.0004 |
| **Diesel Light-Duty Trucks** | | | | |
| Advanced | 0.0015 | 0.0005 | 0.0009 | 0.0003 |
| Moderate | 0.0014 | 0.0005 | 0.0009 | 0.0003 |
| Uncontrolled | 0.0017 | 0.0006 | 0.0010 | 0.0004 |
| **Diesel Heavy-Duty Vehicles** | | | | |
| Advanced | 0.048 | 0.0051 | 0.030 | 0.0032 |
| Moderate | 0.048 | 0.0051 | 0.030 | 0.0032 |
| Uncontrolled | 0.048 | 0.0051 | 0.030 | 0.0032 |
| **Motorcycles** | | | | |
| Non-Catalyst Control | 0.0069 | 0.0672 | 0.0043 | 0.418 |
| Uncontrolled | 0.0087 | 0.0899 | 0.0054 | 0.559 |

Source: U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003*, Annex 3.2, (April 2005), web site: yosemite.epa.gov/OAR/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html.

Note: Reporters should refer to the most recent EPA publication of the *Inventory of U.S. Greenhouse Gas Emissions and Sinks* for Tier 2 vehicle emission factors, when they become available. The Tier 2 Program sets new standards for tailpipe emissions for all passenger vehicles beginning in 2004. The Tier 2 Program also requires reduced levels of sulfur in gasoline.

## Table 1.D.3 Definitions of Emission Control Technologies and Standards

| |
|---|
| **Uncontrolled** |
| • Vehicles manufactured prior to the implementation of pollution control technologies are designated as uncontrolled. Gasoline light-duty cars and trucks (pre-1973), gasoline heavy-duty vehicles (pre-1984), diesel vehicles (pre-1983), and motorcycles (pre-1996) are assumed to have no control technologies in place. |
| **Gasoline Emission Controls** |
| • Non-catalyst – These emission controls were common in gasoline passenger cars and light-duty gasoline trucks during model years (1973-1974) but phased out thereafter, in heavy-duty gasoline vehicles beginning in the mid-1980s, and in motorcycles beginning in 1996. This technology reduces hydrocarbon (HC) and carbon monoxide (CO) emissions through adjustments to ignition timing and air-fuel ratio, air injection into the exhaust manifold, and exhaust gas recirculation (EGR) valves, which also helps meet vehicle NOx standards. |
| • Oxidation Catalyst – This control technology designation represents the introduction of the catalytic converter, and was the most common technology in gasoline passenger cars and light-duty gasoline trucks made from 1975 to 1980 (cars) and 1975 to 1985 (trucks). This technology was also used in some heavy-duty gasoline vehicles between 1982 and 1997. The two-way catalytic converter oxidizes HC and CO, significantly reducing emissions over 80 percent beyond non-catalyst-system capacity. One reason unleaded gasoline was introduced in 1975 was due to the fact that oxidation catalysts cannot function properly with leaded gasoline. |
| • EPA Tier 0 – This emission standard from the Clean Air Act was met through the implementation of early "three-way" catalysts, therefore this technology was used in gasoline passenger cars and light-duty gasoline trucks sold beginning in the early 1980s, and remained common until 1994. This more sophisticated emission control system improves the efficiency of the catalyst by converting CO and HC to $CO_2$ and $H_2O$, reducing $NO_X$ to nitrogen and oxygen, and using an on-board diagnostic computer and oxygen sensor. In addition, this type of catalyst includes a fuel metering system (carburetor or fuel injection) with electronic "trim" (also known as a "closed-loop system"). New cars with three-way catalysts met the Clean Air Act's amended standards (enacted in 1977) of reducing HC to 0.41 g/mile by 1980, CO to 3.4 g/mile by 1981 and $NO_x$ to 1.0 g/mile by 1981. |
| • EPA Tier 1 – This emission standard created through the 1990 amendments to the Clean Air Act limited passenger car NOx emissions to 0.4 g/mi, and HC emissions to 0.25 g/mi. These bounds respectively amounted to a 60 and 40 percent reduction from the EPA Tier 0 standard set in 1981. For light-duty trucks, this standard set emissions at 0.4 to 1.1 g/mi for $NO_x$, and 0.25 to 0.39 g/mi for HCs, depending on the weight of the truck. Emission reductions were met through the use of more advanced emission control systems, and applied to light-duty gasoline vehicles beginning in 1994. These advanced emission control systems included advanced three-way catalysts, electronically controlled fuel injection and ignition timing, EGR, and air injection. |
| • Low Emission Vehicles (LEV) – This emission standard requires a much higher emission control level than the Tier 1 standard. Applied to light-duty gasoline passenger cars and trucks beginning in small numbers in the mid-1990s, LEV includes multi-port fuel injection with adaptive learning, an advanced computer diagnostics systems and advanced and close coupled catalysts with secondary air injection. LEVs as defined here include transitional low-emission vehicles (TLEVs), low emission vehicles, ultra-low emission vehicles (ULEVs) and super ultra-low emission vehicles (SULEVs). In this analysis, all categories of LEVs are treated the same due to the fact that there are very limited CH4 or N2O emission factor data for LEVs to distinguish among the different types of vehicles. Zero emission vehicles (ZEVs) are incorporated into the alternative fuel and advanced technology vehicle assessments. |
| **Diesel Emission Controls** |
| • Moderate control – Improved injection timing technology and combustion system design for light- and heavy-duty diesel vehicles (generally in place in model years 1983 to 1995) are considered moderate control technologies. These controls were implemented to meet emission standards for diesel trucks and buses adopted by the EPA in 1985 to be met in 1991 and 1994. |

- Advanced control – EGR and modern electronic control of the fuel injection system are designated as advanced control technologies. These technologies provide diesel vehicles with the level of emission control necessary to comply with standards in place from 1996 through 2004.

Source: U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2004*, Annex 3.2 (February 2006), p. A-132-A-133, web site: http://yosemite.epa.gov/oar/globalwarming.nsf/UniqueKeyLookup/RAMR6MBLNQ/$File/06_annex_Chapter%203.pdf.

## Table 1.D.4: Predominant Control Technology by Model Year

| Vehicle Type | Model Year | Predominant Control Technology |
|---|---|---|
| Gasoline Passenger Cars | 2000 and Later | Low Emission Vehicle |
| | 1995-1999 | EPA Tier 1 |
| | 1981-1994 | EPA Tier 0 |
| | 1975-1980 | Oxidation Catalyst |
| | 1973-1974 | Non-catalyst |
| | 1972 and Earlier | Uncontrolled |
| Gasoline Light-Duty Trucks | 2001 and Later | Low Emission Vehicle |
| | 1995-2000 | EPA Tier 1 |
| | 1986-1994 | EPA Tier 0 |
| | 1975-1985 | Oxidation Catalyst |
| | 1973-1974 | Non-catalyst |
| | 1972 and Earlier | Uncontrolled |
| Gasoline Heavy-Duty Vehicles | 1996 and Later | EPA Tier 1 |
| | 1985-1995 | Non-catalyst |
| | 1984 and Earlier | Uncontrolled |
| Diesel Vehicles (Passenger Cars and Light- and Heavy-Duty Trucks) | 1996 and Later | Advanced |
| | 1983-1995 | Moderate |
| | 1982 and Earlier | Uncontrolled |
| Motorcycles | 1996 and Later | Non-Catalyst Control |
| | 1995 and Earlier | Uncontrolled |

Source: U.S. Environmental Protection Agency, Inventory of U.S. Greenhouse Gases Emissions and Sinks: 1990-2003, EPA 430-R-05-003, April 15, 2005, Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Tables 3-24, 3-25, 3-26, and 3-27.

### 1.D.3.2.2 Off-Road Vehicles and Marine Vessels

For off-road vehicles, the IPCC developed methane and nitrous oxide emissions factors covering ocean-going ships, boats, locomotives, agricultural equipment, and construction equipment. The emissions factors are expressed in terms of grams per kilogram fuel and grams per megajoule.[42] Some off-road vehicle operators may keep records of fuel consumption or vehicle miles traveled, although for many off-road vehicle types (such as construction equipment), activity data may only be available in terms of hours of use.

For off-road vehicles and marine vessels, methane and nitrous oxide estimates using the inference method, when fuel or energy consumption data are known, are rated "A," provided IPCC non-road mobile source-specific emissions factors are used.[43]

Methane and nitrous oxide estimates using the inference method, when fuel or energy consumption data are not known but are calculated based on other activity data (e.g., distance traveled, hours, or horsepower-hours of operation) are rated "B," provided fuel economy factors are vehicle model-specific factors, or are based on the engine manufacturer specifications or other operation-specific data source. For freight transport, reporters must take into account time spent idling if estimating fuel consumption based on other activity data.

Methane and nitrous oxide estimates using the inference method, when fuel or energy consumption data are not known but are calculated based on default/generic fuel economy values derived from the Oak Ridge National Lab's Transportation Energy Book[44] (e.g., based on different or unspecific engine model) other activity data (e.g., distance traveled, hours, or horsepower-hours of operation) are rated "C."

#### 1.D.3.2.3 Aircraft

The IPCC provides a "Tier II" method for calculating nitrous oxide and methane emissions from aviation, based on distinguishing between Landing and Take-off Operations (LTO) and cruise operations (flight at altitude). Close examination of the IPCC emissions factors suggests that for greenhouse gases, however, the two methods are based upon a single default emissions factor per kilogram of fuel burned.[45] For aircraft, the IPCC developed methane and nitrous oxide emissions factors covering jet and turboprop aircraft and gasoline (piston) aircraft. The emissions factors are expressed in terms of grams per kilogram fuel and grams per (lower heating value) megajoule.[46]

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[42] Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual* (Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories), Table 1-47, pp. 1.89, web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.
[43] *Ibid*.
[44] Oak Ridge National Laboratory, *Transportation Energy Data Book*, Energy Efficiency and Renewable Energy program, U.S. Department of Energy, web site: http://cta.ornl.gov/data/index.html.
[45] This is the case for carbon dioxide, and probably the case for nitrous oxide and methane.
[46] Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual* (Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories), Table 1-47, p. 189, web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

For aircraft, methane and nitrous oxide estimates using the inference method based on individual jet engine aircraft LTO and cruise data and IPCC default emissions factors[47] are rated "A."

Methane and nitrous oxide estimates using the inference method, when fuel or energy consumption data are known, using either the LTO approach or emissions per kilogram of fuel, are rated "B," provided IPCC aircraft-specific emissions factors[48] are used.

Methane and nitrous oxide estimates using the inference method, when fuel or energy consumption data are not known but are calculated based on other activity data (e.g., distance traveled, hours, or horsepower-hours of operation), are rated "C," provided fuel economy factors are vehicle model-specific factors, or are based on the engine manufacturer specifications or other operation-specific data source. For freight transport, reporters must take into account time spent idling if estimating fuel consumption based on other activity data.

Methane and nitrous oxide estimates using the inference method, when fuel or energy consumption data are not known but are calculated based on other activity data (e.g., distance traveled, hours, or horsepower-hours of operation) and default/generic fuel economy values from any other source or estimations are rated "D."

### 1.D.3.3 Hydrofluorocarbons from Mobile Refrigeration and Air Conditioning

This section includes all transportation vehicles that have mobile refrigeration and air conditioning systems, including those vehicles that do not produce anthropogenic carbon dioxide emissions or direct methane and nitrous oxide emissions, but can emit hydrofluorocarbons from refrigeration and/or air conditioning systems.

Hydrofluorocarbon estimates using the mass balance method are rated "A," provided the mass balance estimates have the following features and data availability:

- Amount of refrigerant inventory per year charged into new and retrofitted equipment.
- Amount of refrigerant inventory per year used to service equipment and replace leaked and vented refrigerant.
- Total full capacity of each system, including original full capacity of retiring equipment.
- Quantities of refrigerants recovered per year from all vehicles and mobile systems.

Hydrofluorocarbon estimates using the mass balance method are rated "C" if the estimates are based on emissions factors (percent) for initial charge, annual leakage during operation, capacity remaining at disposal, and recovery. This mass balance approach using emissions factors is based on the Tier 2 approach from the IPCC Good Practice Guidance and the EPA Climate

[47] Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual* (Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories), Tables 1-50 and 1-51, pp. 196-197, web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.
[48] Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual* (Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories), Tables 1-50 and 1-51, pp. 196-197, web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

Leaders voluntary program method. These authorities provide default values for mobile air conditioning equipment input parameters, including emissions factors.[49]

All methods and ratings discussed in this chapter for estimating greenhouse gas emissions from mobile sources are summarized below in Table 1.D.5.

### Table 1.D.5. Summary of Methods and Ratings for Estimates of Greenhouse Gas Emissions from Mobile Sources

| Method Description | Rating |
|---|---|
| **Carbon Dioxide Emissions from Highway Vehicles** | |
| Mass balance based on fuel volume burned, or bulk purchase data adjusted for stock change used with measured density or heating value and carbon content or with default emissions factors | A |
| Mass balance based on bulk fuel purchase not accounting for stock change used with default emissions factors | B |
| Mass balance based on distance traveled and fuel economy data, or hours, horsepower-hours, or ton-distance shipped and fuel consumption per unit activity data used with default emissions factors | C |
| Mass balance based on fuel price or expenditure data used with default emissions factors | D |
| **Carbon Dioxide Emissions from Off-Road Vehicles, Including Diesel Locomotives** | |
| Mass balance based on actual fuel consumed or via bulk purchase data that accounts for stock change used with measured density or heating value and carbon content or with default emissions factors | A |
| Mass balance using fuel consumption based on bulk purchase not accounting for stock change used with default emissions factors | B |
| Mass balance based on distance traveled and fuel economy for each engine, or hours, horsepower hours of operation, or ton-distance shipped and fuel consumed per unit activity data used with default emissions factors | C |
| Mass balance based on fuel price data only or default factors for fuel consumption per unit activity data used with default emissions factors | D |
| **Carbon Dioxide Emissions from Water Borne Vessels** | |
| Mass balance based on actual fuel quantities consumed or bulk purchase records accounting for stock change used with measured density, heating value, and/or carbon content and/or with specific fuel type and default emissions factors | A |
| Mass balance based on bulk fuel purchase data not adjusted for stock change used with default emissions factors | B |
| Mass balance based on distance traveled data and fuel economy for each engine, or hours, horsepower hours of operation, or ton-distance shipped and specific information on fuel consumed per unit activity data used with default emissions factors | C |
| Mass balance based on fuel price data only or default factors for fuel consumption per unit of activity data used with default emissions factors | D |
| **Carbon Dioxide Emissions from Aircraft** | |
| Mass balance based on measured quantities loaded into vehicle or bulk purchase records accounting for stock change used with measured density or heating value, and carbon content or with default emissions factors | A |
| Mass balance fuel consumption volume from bulk purchase data not adjusted for stock change used with default emissions factors | B |

[49] Intergovernmental Panel on Climate Change, *Good Proactive Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (June 2001), web site: www.ipcc-nggip.iges.or.jp/public/gp/english/.

| Method Description | Rating |
|---|---|
| Mass balance based on distance traveled and fuel economy for each engine, or hours, horsepower hours, or ton-distance shipped and specific information on fuel consumed per unit activity data used with default emissions factors | C |
| Mass balance based on fuel price data only or default factors for fuel consumption per unit of activity data used with default emissions factors | D |
| **Methane and Nitrous Oxide from Highway Vehicles** | |
| Inference based on vehicle distance traveled or fuel consumption and an emissions factor for specific vehicle types, provided combustion and emission control technology are known for each vehicle | A |
| Inference based on total vehicle distance traveled for an uncharacterized vehicle mix and weighted average emissions factor | B |
| **Methane and Nitrous Oxide from Off-Road Vehicles and Marine Vessels** | |
| Inference based on fuel or energy consumption data and specific IPCC emissions factors | A |
| Inference based other activity data (e.g., distance traveled) to calculate fuel consumption, with model-specific fuel economy factors and IPCC emissions factors | B |
| Inference based on default/generic fuel economy values and available activity data with IPCC emissions factors | C |
| **Methane and Nitrous Oxide from Aircraft** | |
| Inference based on individual jet engine aircraft LTO and cruise data and IPCC default emissions factors | A |
| Known fuel/energy consumption and either LTO approach or emissions per kilogram fuel with IPCC default emissions factors | B |
| Inference based on other activity data (e.g., distance traveled) use to calculate fuel consumption used with default IPCC emission factors, provided fuel economy data are model-specific | C |
| Inference using other activity data (e.g., hours) and default/generic fuel economy values with IPCC default emissions factors | D |
| **Hydrofluorocarbons from Mobile Refrigeration and Air Conditioning** | |
| Mass balance, provided specific features and data availability | A |
| Mass balance based on emissions factors (percent) for initial charge, annual leakage, capacity remaining at disposal, and recovery | C |

## 1.D.4 Special Situations

### 1.D.4.1 Electric, Fuel Cell, and Bio-Fueled Vehicles

Whenever mobile emissions sources combust liquid or gaseous fuel, they emit carbon dioxide, methane, and nitrous oxide. The relative amounts of those emissions will depend on many factors, but the actual gases emitted are the same. The exceptions to this rule are electric vehicles, fuel cell vehicles, and bio-fueled vehicles because they do not combust fuels or the fuels they do combust are biogenic.

Electric vehicles have no tailpipe emissions, although there may be significant upstream emissions depending on the source of the electricity. If produced from renewable energy there will be no upstream emissions, but if generated from fossil fuels there will be a significant upstream share of emissions in the form of carbon dioxide, methane, and nitrous oxide. Upstream emissions from electricity that is subsequently used in electric vehicles should be estimated by the entity operating the vehicles as described in Part F, “Indirect Emissions.”

Hydrogen-powered fuel cell vehicles also have no tailpipe emissions of reportable greenhouse gases, although there may be significant upstream emissions depending on the source of the hydrogen. If the hydrogen is produced from renewable energy or nuclear energy, there will be no upstream emissions. If it is reformed from natural gas or other fossil fuels – and sequestration does not occur – there will be a significant upstream share of greenhouse gas emissions in the form of carbon dioxide, methane, and nitrous oxide. If the hydrogen is generated from natural gas, any upstream emissions may be reported using guidelines for industrial process direct emissions by the entity processing the natural gas. If the hydrogen used in the fuel cell is generated from water by electrolysis, the entity producing the hydrogen may report any indirect emissions from electricity that was used to charge a battery used in the electrolytic process, if applicable.

Reporters that operate vehicles using pure biofuels within their entity should not add the carbon dioxide emissions from those fuels to their inventory of mobile source emissions because such emissions are considered biogenic and the recycling of the carbon is not credited elsewhere. If vehicles are operating on a gasoline/alcohol blend such as E85, or "gasohol," reporters should calculate emissions for the hydrocarbon fraction of the fuel that is combusted and include those emissions with the inventory of carbon dioxide from mobile sources. For example, E85 is composed of 85 percent ethanol and 15 percent gasoline by volume, and the carbon dioxide emissions from the gasoline portion of the fuel should be calculated according to the methods described above.

## Part E: Industrial Processes

Outline

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# Technical Guidelines Chapter 1, Part E: Industrial Processes

## 1.E.1 Overview

This Part of the Technical Guidelines presents methods for estimating emissions of greenhouse gases from industrial processes, energy industries, and waste handling. These sectors encompass many processes, activities, and products. Emission sources in these sectors are also varied, and include the byproducts of chemical transformations, the use and discharge of gases, and periodic, non-production-related practices such as maintenance and system upgrades. Discussion of energy industries includes the coal, natural gas and oil industries, while the waste sector focuses on emissions from landfills and wastewater.

This Part does not attempt to provide a comprehensive list of sources or detailed guidance for estimating emissions from all processes. It does, however, describe and rank methods for estimating emissions from the following industries and industrial activities: adipic acid production; aluminum production; ammonia production; cement production; coal mining; HCFC-22 production; industrial use of hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride ($SF_6$); iron and steel production; landfill methane; lime production; limestone and dolomite use; magnesium production; methanol production; nitric acid production; the oil and natural gas industries; semiconductor manufacturing; soda ash production and use; and domestic and industrial wastewater handling.

Estimation methods for industrial sources include direct monitoring (including continuous and periodic emission monitoring), mass balance, and inference based on derived emissions factors. This section defines these methods and provides guidance for implementing emission estimates for various industrial processes, but reporters are encouraged to consult published authorities for more complete instruction,[50] particularly for industries in which emissions originate from a variety of sources or require complex estimation methods.

Reporters cataloging industrial emissions should ensure that the same emissions are not "double counted," or recorded simultaneously under different sections. In particular, where the primary purpose of an industrial process is energy production (in the form of heat or electricity), emissions should be attributed to stationary combustion (see Part C, "Stationary Combustion").

## 1.E.2 Emission Sources

### 1.E.2.1 Process Emissions

Emissions are generated and released during the chemical transformation of materials at some stage of the production process in many industries. These emissions are referred to as "process emissions" and are usually the byproduct of a known chemical reaction. Greenhouse gas emissions from processes of this type include carbon dioxide ($CO_2$), methane ($CH_4$), nitrous oxide ($N_2O$), trifluoromethane (HFC-23), and perfluorocarbons (PFCs). Industries and industrial

[50] In particular, reporters should refer to subsection 1.E.4 for a list of sector-specific guidance resources.

activities that generate emissions through chemical processes include adipic acid production, chlorodifluoromethane (HCFC-22) production, aluminum production, cement manufacturing, iron and steel production, lime manufacture, limestone and dolomite use, nitric acid production, and soda ash manufacture and use. Process emissions from industrial chemical reactions represent 4 to 5 percent of total U.S. greenhouse gas emissions on a carbon dioxide equivalent basis.[51]

### 1.E.2.2 Fugitive Emissions

"Fugitive emissions" is a broad term that includes both unintentional and sometimes intended emissions from non-distinct or non-confined sources. Fugitive emissions occur during the production and distribution of a chemical, compound, or mixture of compounds and are usually the result of leaks in transportation or processing systems. Fugitive emissions can be significant in terms of both carbon dioxide equivalents and percentages of equipment charge.

Reporters may expect fugitive emissions in industries where greenhouse gases are transported or used in a specific process or application. Relevant industrial processes include magnesium production, production and use of refrigerants, oil and natural gas extraction, processing and transportation, and the production and use of hydrofluorocarbons, perfluorocarbons and sulfur hexafluoride. Fugitive emissions may also occur during the extraction, transport and preparation of coal or from anaerobic decomposition of wastes in landfills. Fugitive emissions account for nearly 6 percent of all U.S. greenhouse gas emissions.[52] The natural gas industry is the industry most likely to report fugitive emissions on a significant scale.

Fugitive emissions may also result from "non-routine" activities in industries that transport or process large volumes of greenhouse gases. Non-routine activities are those that are not part of typical processing activities, but occur periodically as a part of overall system operations. These activities can be either planned or unplanned, and include maintenance and turnaround activities, line and equipment purging, and unplanned system depressurization in response to emergency conditions.

### 1.E.2.3 Process Emissions vs. Combustion Emissions

Many industrial processes are dependent on a significant amount of energy, such as process heat, electricity use, or some other form of energy consumption. A key distinction of industrial emissions, however, is that they result from a non-energy-related activity. For processes in which the use or consumption of one material serves more than one purpose, it is important for reporters to accurately allocate emissions and to avoid double counting.

The iron industry provides an example of this situation, where coke is used in blast furnaces to provide process heat as well as to reduce the iron in raw ore. In these cases, reporters should consider whether the role of the process in question is to provide usable energy or is an intrinsic

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[51] U.S. Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2004* (December 2005), web site: ftp://ftp.eia.doe.gov/pub/oiaf/1605/cdrom/pdf/ggrpt/057304.pdf.
[52] *IBID.*

element of the industrial process. As in the case of the iron industry, where the reduction of iron is a critical component in producing crude iron, emissions should be counted as industrial. Where the primary purpose of a process is to use the heat that is released, emissions should be attributable to stationary combustion.

## 1.E.3 Estimation Methods

### 1.E.3.1 Direct Measurement

Reporters may directly monitor their industrial process stack emissions even when not required to do so by the Clean Air Act Amendments. They may be complying with other environmental regulations, or collecting process performance information for internal purposes. In cases where emissions are channeled through dedicated streams, direct measurements may help reporters differentiate between stationary combustion and industrial process emissions. Direct emission measurements can be taken either continuously or periodically.

Continuous emission monitoring (CEM) is one method of direct measurement. CEM requires inserting a probe into the exhaust stack of an industrial process system, and continuously measuring and recording concentrations of gases that flow through the exhaust pipe. Due to its relatively high cost and a general absence of regulatory requirements, however, CEM is fairly uncommon for measuring greenhouse gas emissions from industrial processes. Nevertheless, continuous or frequent measurements are critical for some industrial entities to ensure process efficiency (e.g., HCFC-22 production), and are therefore performed without regulation. Those measurements are often made rigorously because they have a high economic impact.

Emissions can also be estimated through periodic direct measurements. Like CEM, periodic measurements directly measure emissions passing through exhaust streams. As the name implies, though, periodic measurements only provide samples of the exhaust stream at particular points in time. The data gathered from these measurements are used in conjunction with estimates of exhaust flow rates and other activity data to extrapolate to total emissions over a given period of time. Since periodic measurements yield a sample of total emissions, any difference in the quality of data with the CEM approach will depend upon the information available about the emissions profile. If exhaust flow rates are well known, as might be the case for a plant that operates at the same level continuously, there may be very little difference in emissions estimates from the two methods. For a plant whose output varies over time, producing a data set from periodic measures whose accuracy compares with that from CEM measurements can be challenging.

Reporters should use unregulated emissions monitoring data with caution; measured emissions data are only as accurate as the apparatus used to take them. If the monitoring is not continuous, the measured pollutant concentration data that are recorded represent only the emissions at a particular moment in time for a particular location within the stack. Moving from a concentration sample to an accurate estimate of mass emissions over time requires calculating mass flow within the stack, which is sometimes a difficult and uncertain procedure. In addition, estimating industrial process emissions based on one-time or periodic measurements usually requires calibrating the monitor using activity data, requiring that measurement systems be re-assessed

whenever routine operations are altered, including changes to production processes or volumes. In the end, the activity data itself may provide a more accurate result at a lower cost than using periodic or unregulated emissions monitoring data.

To ensure consistency and reliability, reporters using any direct measurement data should ensure that their measurement systems are subject to periodic calibration practices. Due to the wide variety of emission sources and methods for measuring them, this guidance does not provide specific instruction on calibrating measurement systems for each emission source discussed herein.

Reporters to the Voluntary Reporting of Greenhouse Gases (1605(b)) Program that directly measure their emissions are expected to follow internal quality control assessments that verify the accuracy of their measurement systems. Specific, internationally accepted standard methods for measuring greenhouse gas emissions exist for some industries. Where specific methods exist, reporters are encouraged to follow them; where possible, this guidance refers reporters to readily available, published authorities that provide specific instruction of this nature.

In the absence of industry-specific standard methods, reporters should follow internationally accepted, generalized standard methods for managing and calibrating measurement systems. One such organization providing guidance for complying with internationally accepted standards is the International Organization for Standardization (ISO). Reporters seeking general guidance on methods for managing and calibrating measurement systems should consult the ISO's guidance document, *ISO 10012 - Measurement Management Systems - Requirements for Measurement Processes and Measuring Equipment*.[53]

### 1.E.3.2 Mass (or Material) Balance

The mass balance method is based on the premise that the mass and energy content of all components of a substance that go into a process must be chemically accounted for in some form as output. Estimating emissions using the mass balance method requires knowledge of the specific chemical reaction and data on the quantity of raw materials consumed or product manufactured. This information is used to estimate the mass of materials from at least one part of the overall chemical reaction. Emissions can then be calculated using the known molecular proportions (stoichiometric ratios) of the reaction formula.

The accuracy of mass balance estimates will depend on the precision of the data available to reporters and the nature of the activity causing the emission. While the ratio of reactants to products of a particular chemical reaction is constant, reporters may not have accurate data on the quantity of either products or reactants associated with a particular process. For instance, one stage in the production of lime involves producing quicklime by heating limestone. This process releases carbon dioxide, as shown in the following equation:

$$\mathbf{CaCO_3\ (limestone) + heat \rightarrow CaO\ (quicklime) + CO_2.}$$

[53] Available at web site: www.iso.ch.

Following the principles of the mass balance method, a reporter could estimate the mass of carbon dioxide emissions, provided data on the mass of limestone consumed and the molecular ratio of limestone to carbon dioxide were available. This assumes, however, that the limestone used by the facility is 100 percent pure, while limestone purity can actually be quite variable. If the reporter assumed 100 percent limestone purity when the facility was processing 85 percent pure limestone, for example, the result would be an emissions overestimate of nearly 18 percent.

Although for many reporters it is good business practice to collect and maintain plant-specific activity data, in some instances reporters will not have access to plant-specific data about the raw materials consumed or the products manufactured. In those cases, reporters can use default values that represent common industry standards for relevant parameters. Mass balance estimates using default values will vary from industry to industry, depending on how variable the particular default value is within that industry.

Fugitive emissions from stationary use of a chemical (e.g., refrigerants or insulators in a sealed environment) are most easily measured when a known quantity of gas is purchased to replace losses that have occurred over a given time period. Purchasing refrigerant to re-fill a refrigerating unit is an example of this situation. In these cases, fugitive emissions are equal to new purchases/inputs minus the volume of gas required to satisfy net growth in the equipment stock. Net growth means the difference between the volumes of new and retiring equipment. This type of estimation falls under the category of mass balance because it tracks specific quantities of materials included in a process.

Some industries, including magnesium and aluminum foundries, will generate emissions through the use and subsequent discharge of greenhouse or ozone precursor gases. For those industries, emissions are usually easily estimated, as they are equal to the quantity of gas purchased minus the quantity recycled over a given time frame. This type of accounting is also considered a mass balance approach.

### 1.E.3.3 Inference

If data on raw materials or products are not available, reporters can estimate emissions indirectly by inference. The Intergovernmental Panel on Climate Change (IPCC), World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD), American Petroleum Institute (API), U.S. Environmental Protection Agency (EPA), U.S. Energy Information Administration (EIA), and other authorities on greenhouse gas estimation methods provide inference-based methodologies to estimate emissions associated with numerous industrial processes.[54] The equations use activity-level data and an associated emissions factor, according to the following general formula:

$$E = AL * EF$$

**Where:**

**E = Emission**

[54] Reporters should refer to subsection 1.E.4 for a list of sector-specific guidance and references.

**AL = Activity Level**

**EF = Emissions Factor**

An emissions factor is a representative value that relates the quantity of a constituent emitted with an activity associated with the production of that constituent.[55] The heart of the inference approach to estimating emissions is the data source that generates this emissions factor. Inference-based factors are derived from statistical sample data from a pool of resources that have certain parameters in common with the process that is being estimated.

The accuracy of an inference-based estimate depends fundamentally on the accuracy and representativeness of the emissions factor used, and the natural variability of the process in question. Emissions factors can be based on a variety of data sources. For instance, an emissions factor for a given plant can be estimated indirectly from prior direct observation or measurement of that plant. Alternatively, the emissions factor could be based on observations or measurements made at a comparable plant.

Emissions factors can also be based on average measurements for plants of a specific type, or for an industry in general. Factors of this type are usually referred to as default emissions factors. Depending on how default emissions factors are derived, these emissions factors are usually associated with a more significant margin of error, and can usually be assumed to provide less accurate estimates.

Inference-based estimates may involve additional arithmetic steps to estimate either activity level or an emissions factor. For example, reporters may need to use activity data in conjunction with an engineering estimate based on measured or default site-specific operating parameters and model coefficients. This method differs from direct measurement-based estimation because it does not involve direct measurement of emissions, but rather uses the direct measurement of, or site-specific default value for, a related operating parameter. The operating parameter is used to model an emissions factor. The resulting emissions factor is used in conjunction with site-specific activity data, such as quantity of chemicals consumed or output of a product.

Fugitive emissions can be estimated using inference-based methods either at the facility or at the component level. Facility-level estimates can be based on published or industry accepted figures of estimated emissions from similar facilities. Component-level estimates of fugitive emissions use default emission/leak rates for each of the individual components used in a facility. Emission estimates for each component are then summed together to represent all of the emissions from that facility. Emissions from semiconductor manufacturing can also be estimated using inference-based methods.

[55] U.S. Environmental Protection Agency, AP-42 Series, "Introduction to AP-42," Volume I, Fifth Edition (January 1995), web site: www.epa.gov/ttn/chief/ap42/index.html.

## 1.E.4 Sector-Specific Emission Estimation Guidance

Reporters should consult the appropriate references, which are cited throughout this section, for detailed descriptions of each estimation methodology. Some of the more useful references include:

- American Petroleum Institute (API), *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* (February, 2004), web site: api-ec.api.org/filelibrary/2004_COMPENDIUM.pdf.

- California Climate Action Registry, *Industry-Specific Protocols*, web site: www.climateregistry.org/PROTOCOLS/.

- Intergovernmental Panel on Climate Change. *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (2000), web site: www.ipcc-nggip.iges.or.jp/public/gp/english/.

- Intergovernmental Panel on Climate Change. *Revised 1996 Guidelines for National Greenhouse Gas Inventories* (1997), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

- U.S. Energy Information Administration, *Documentation for Emissions of Greenhouse Gases in the United 2003* (May 2005), web site: www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf.

- U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2003* (April 15, 2005), web site: http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html.

- U.S. Environmental Protection Agency, Office of Atmospheric Programs, Climate Protection Partnerships Division, Climate Leaders Program, web site: www.epa.gov/climateleaders/. Specifically, *Climate Leaders Greenhouse Gas Inventory Protocol, Sector Specific Core Module Guidance* (2003), web site: http://www.epa.gov/climateleaders/resources/sector.html.

- U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2003* (April 15, 2005), web site: yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html.

- World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD), *GHG Protocol Initiative* (2003), web site: www.ghgprotocol.org, specifically, WRI/WBCSD's "GHG Protocol Initiative Downloadable Calculation Tools,

Guidance Section," web site: www.ghgprotocol.org/templates/GHG5/layout.asp?MenuID=849.

## 1.E.4.1 Industrial Processes

### 1.E.4.1.1 Adipic Acid Production

Adipic acid is a white, crystalline powder used primarily for the manufacture of synthetic nylon fibers; approximately 90 percent of the adipic acid produced in the United States is used for the manufacture of nylon 6,6.[56] Adipic acid is also used in the production of gelatins, beverages, oils, snack foods, plasticizers for polyvinyl chloride and polyurethane resins, wire coatings, adhesives, lubricants and dyes. Four plants produce all of the adipic acid manufactured in the United States.

Nitrous oxide ($N_2O$) is the primary greenhouse gas emitted during the production of adipic acid, which occurs in two stages. In the first stage, cyclohexanone is oxidized to form a mixture of cyclohexanol and cyclohexanone. This mixture is then oxidized with nitric acid ($HNO_3$) to form adipic acid, nitrous oxide, and water. Emission rates depend on specific plant operating parameters and whether or not emissions control technologies are employed. Nitrous oxide emissions can be significantly reduced by emission abatement systems, including nitrous oxide-specific destruction equipment and systems designed to reduce other emissions. Nitrous oxide destruction systems, for instance, can reduce emissions by up to 98 percent.[57]

Reporters are encouraged to use plant-specific, measured estimates of nitrous oxide emissions. CEM measurements will be assigned a rating of "A," provided they are calibrated as discussed in subsection 1.E.3.1. Estimates based on periodic measurements will also be assigned a rating of "A."

If plant-specific data are not available, reporters can use the IPCC default uncontrolled emissions factor of 300 kg nitrous oxide per metric ton adipic acid.[58] If abatement control technologies are employed, reporters should amend this uncontrolled emissions factor by accounting for the destruction and utilization factors[59] of the control technology used. Taking these factors into account, $N_2O$ emissions are calculated using the following formula:

$$N_2O \text{ Emissions} = \text{Emissions factor} * \text{Adipic Acid production} * [1 - (N_2O \text{ Destruction factor} * \text{Abatement system utilization factor})]$$

Table 1.E.1 provides ranges of default destruction-factor and utilization-factor values for various emission abatement technologies to adjust the emissions factor to reflect the particular control

[56] U.S. Environmental Protection Agency, *Inventory of Greenhouse Gas Emissions and Sinks: 1990-2003* (2005).
[57] Radian Corporation, *Nitrous Oxide Emissions from Adipic Acid Manufacturing* (Rochester, NY, January 1992).
[58] Intergovernmental Panel on Climate Change, NGGIP, *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (2000), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*.
[59] The utilization factor accounts for the percent effectiveness of the control device based on issues related to installation, start-up, and maintenance of the device. For example, the higher the down time of the control device, the lower the utilization factor.

scenario for the plant.[60] Those reporters using these default ranges should select the lower end of the range for their point values (e.g., those using defaults and employing catalytic destruction should assume a 90 percent destruction rate and an 80 percent utilization factor).

### Table 1.E.1. Default $N_2O$ Destruction and Utilization Factors for Different Abatement Technologies

| Abatement Technology | $N_2O$ Destruction Factor | Utilization Factor |
|---|---|---|
| Catalytic Destruction | 90-95 percent | 80-98 percent |
| Thermal Destruction | 98-99 percent | 95-99 percent |
| Recycle to Phenol Feedstock | 98-99 percent | 90-98 percent* |
| Recycle to Adipic Acid Feedstock | 90-98 percent | 80- 98 percent** |

* For Recycle-to-Nitric Acid Abatement Systems
**For Recycle-to-Adipic Acid Abatement Systems
Source: Intergovernmental Panel on Climate Change, *Good Practice Guidance and Uncertainty Management for National Greenhouse Gas Inventories* (2000).

Estimates using known destruction and abatement factor values for an abatement system in conjunction with a default emissions rate will be assigned a rating of "B." Estimates based on default destruction and abatement factor values will be assigned a rating of "C."

Ratings of methods for estimating $N_2O$ emissions from adipic acid production are summarized in Table 1.E.2.

### Table 1.E.2. Rating of Estimation Methods for Nitrous Oxide Emissions from Adipic Acid Production

| Estimation Method | Rating |
|---|---|
| Direct measurement, either continuous emissions monitoring or periodic direct measurements | A |
| Default emissions factors using known destruction and utilization factors for an abatement technology, with default emissions rate | B |
| Default emissions factors, using utilization factors, and reflecting an uncontrolled stream or default factor for an abatement technology | C |

#### 1.E.4.1.2 Aluminum Production

Aluminum is produced by electrolytically reducing aluminum oxide via the reaction: $2AL_2O_3 + 3C = 4AL + 3CO_2$. This process results in emissions of carbon dioxide and PFCs and can be completed using different technologies, each of which may feature more than one emission estimation method. In addition, sulfur hexafluoride may occasionally be used as a cover gas for special foundry products, with emissions equal to the volume of consumption. Reporters should begin by familiarizing themselves with the types of facilities (and their accompanying processes) for which they will be estimating emissions.

##### 1.E.4.1.2.1 Carbon Dioxide Emissions from the Smelting Process

[60] Intergovernmental Panel on Climate Change, NGGIP, *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (2000), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*.

Production of primary aluminum involves two stages: alumina production and its subsequent reduction to aluminum. In the first stage alumina ($Al_2O_3$) is produced by calcining ground, purified bauxite ore. While this stage generates emissions, reporters will not address them in this section; instead they should refer to the methods outlined in Part C, "Stationary Combustion."

The second stage, referred to as smelting, involves electrolyzing the alumina and subsequently reducing it to create primary aluminum. The simultaneous oxidation of a carbon anode (which serves as the reducing agent) generates carbon dioxide emissions.

This stage accounts for the majority of the carbon dioxide emissions emitted directly from aluminum production and can be accomplished using either of two processes: the Soderberg process or the pre-baked anode process. Although analogous, these processes differ in the form of the electrode. Because they also differ in their emission characteristics, reporters should ascertain the type of facility for which they are reporting before proceeding with emission estimates.

The most accurate method for estimating carbon dioxide emissions from primary aluminum production is a mass balance approach based on the quantity and composition of the reducing agents consumed. Emission estimates using these data will be assigned a rating of "A."

If data on the composition of the carbon anodes are not available, WRI provides "industry typical" composition data for pre-baked and Soderberg anodes.[61] Alternatively, IPCC provides default emissions factors for a variety of reducing agents, including pre-baked anodes and coal electrodes.[62] Emission estimates calculated using either of these values in conjunction with data on the quantity of reducing agent consumed will be assigned a rating of "B."

If reporters do not have access to reducing agent consumption data, default emission factors for carbon dioxide emissions from primary aluminum production are provided in Table 1.E.3.

### Table 1.E.3. Default $CO_2$ Emissions Factors for Primary Aluminum Production

| Process | Ton $CO_2$ per metric ton Aluminum |
|---|---|
| Soderberg Process | 1.7 |
| Pre-baked Anode Process | 1.6 |

Source: WRI/WBCSD *GHG Protocol, Guidance to Calculation Tools*, web site: http://www.ghgprotocol.org/DocRoot/J2B1nGP5lVfVYCrVxWiH/co2-aluminum.pdf

Emission estimates based on these default values will be assigned a rating of "B."[63]

[61] World Resources Institute. *Calculating $CO_2$ Emission from the Production of Aluminum* (2003), web site: www.ghgprotocol.org/DocRoot/qo2ApdlI8wMiWcOHFWjp/co2-aluminum.pdf.
[62] Intergovernmental Panel on Climate Change. *Revised 1996 Guidelines for National Greenhouse Gas Inventories-Reference Manual* (1997) web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.
[63] Evidence suggests that there is little variation in $CO_2$ emissions from the consumption of carbon anodes for aluminum smelting among similar technologies. Accordingly, this value rating is higher than is typical of most default emissions factors.

#### 1.E.4.1.2.2 PFC Emissions from Aluminum Production

Aluminum smelting also generates emissions of two perfluorocarbons (PFCs): tetrafluoromethane ($CF_4$) and hexafluoroethane ($C_2F_6$). $CF_4$ and $C_2F_6$ are produced when aluminum production is interrupted due to a lack of alumina near the anode and, as a result of an elevated voltage, carbon reacts with fluoride salts in the electrolytic bath to form PFCs. Such interruptions are commonly referred to as "anode effects." Anode effects are short duration events that occur periodically on all Hall-Héroult electrolytic cells.

There are three parameters that affect PFC emissions from smelters: (1) aluminum production, (2) anode effect minutes per cell day (or anode effect over-voltage for the Pechiney method), and (3) smelter-specific "slope factors" (or over-voltage coefficients for the Pechiney method). These three parameters determine the quantity of PFCs emitted per anode effect minute (or per anode effect over-voltage) per cell day. Both the IPCC Tier 3b and Tier 2 approaches distinguish between the Slope Method and the Pechiney Overvoltage Method. The IPCC Tier 3b approach uses smelter-specific information for each of these parameters, and is consequently the most accurate approach (other than CEM, which is not currently used). The IPCC Tier 2 approach uses smelter-specific information for the first and second parameters, but relies on technology-specific slope factors for the last. The least accurate IPCC Tier 1 approach uses smelter-specific information for the first parameter only.

Chapter 3.3 of IPCC's *Good Practice Guidance*,[64] "PFC Emissions from Aluminum Production," contains a detailed discussion of the various methods. This document, as well as the periodic updates of the IPCC's *Guidelines for National Greenhouse Gas Inventories*,[65] is a valuable source of information on both methods and the most recent default emissions factors. In addition, the U.S. Environmental Protection Agency (EPA) and the International Aluminum Institute have developed a Protocol for measurement of $CF_4$ and $C_2F_6$ from primary aluminum production.[66] The protocol was produced with the purpose of fostering consistency in smelter-specific sampling programs and to assist with developing accurate PFC inventories based on IPCC Tier 3b method.[67]

There are a number of ways to estimate PFC emissions from anode effects. The most accurate method is to take representative field measurements and to use this information to develop smelter-specific slope factors that reflect either a) the relationship between emissions and anode effect minutes per cell day (referred to as the Slope method) or b) the relationship between emissions and anode effect over-voltage (referred to as the Pechiney Over-voltage method).

To estimate emissions using the Slope method, the slope factor is then multiplied by the anode effect minutes per cell day and by aluminum production:

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[64] Intergovernmental Panel on Climate Change, NGGIP, *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (2000), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*.
[65] Intergovernmental Panel on Climate Change. *Revised 1996 Guidelines for National Greenhouse Gas Inventories-Reference Manual* (1997), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.
[66] U.S. Environmental Protection Agency / International Aluminum Institute. *PFC Measurement Protocol* (May 2003), web site: www.climatevision.gov/sectors/aluminum/protocols.html.
[67] This Protocol provides guidance for individual facilities to develop detailed plans for sampling and analysis based on plant-specific technology, anode effect data, and chosen measurement instrumentation.

**PFC Emissions / ton Aluminum = Slope * Anode effect minutes per cell day**

To estimate emissions using the Pechiney Over-voltage method, an over-voltage coefficient is multiplied by the anode effect over-voltage divided by the current efficiency of the aluminum production process:

**PFC Emissions / ton Aluminum =**
**Over-voltage coefficient * (Anode effect over-voltage / Current efficiency)**

Emission estimates using either of these methods will be assigned a rating of "A."

In the absence of smelter-specific slope factors, reporters can estimate emissions using production data in conjunction with technology-specific slope factors, anode effect frequency and duration data (if using the Slope method) or with production data in conjunction with technology-specific over-voltage coefficients and anode effect over-voltage. Reporters should consult IPCC's *Good Practice Guidance*[68] in order to determine which method is most applicable to their facility and for the detailed methodology. Emission estimates using either of these approaches will be assigned a rating of "B."

If anode effect data are unavailable, reporters should use the most recent default emissions factors available through the IPCC.[69] Emissions estimates based on these default values will be assigned a rating of "C."

### 1.E.4.1.2.3 $SF_6$ Emissions from Aluminum Production

Sulfur hexafluoride ($SF_6$) is used as a cover gas during the production of certain aluminum foundry products. It is generally accepted that none of the sulfur hexafluoride is reacted with or consumed while used, and that it is all emitted directly into the atmosphere after use.[70] Thus, the amount of sulfur hexafluoride emitted from aluminum foundries is equal to the amount consumed:

**$SF_6$ Emissions = $SF_6$ Consumption.**

Consumption data can be easily inferred from purchase data. Estimates based on purchase data will be assigned a rating of "A."

Ratings of methods for estimating emissions from aluminum production are summarized in Table 1.E.4.

[68] Intergovernmental Panel on Climate Change, NGGIP, *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (2000), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*.
[69] Intergovernmental Panel on Climate Change, *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (2000), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*.
[70] Ibid.

**Table 1.E.4. Rating of Estimation Methods for Carbon Dioxide, PFC, and Sulfur Hexafluoride Emissions from Aluminum Production**

| Estimation Method | Rating |
|---|---|
| **Carbon Dioxide Emissions From The Smelting Process** | |
| Mass balance based on quantity and composition of reducing agents consumed | A |
| Mass balance based on default anode composition values and data on quantity of reducing agent consumed | B |
| Default emissions factors | B |
| **PFC Emissions From Aluminum Production** | |
| Smelter-specific slope factors based on representative field measurements | A |
| Technology-specific slope factors (or over-voltage coefficients), anode effect frequency and duration (or anode effect over voltage), and production data | B |
| Inference method based on most recent IPCC default emissions factors | C |
| **$SF_6$ Emissions From Aluminum Production** | |
| Inference method using purchase data | A |

### 1.E.4.1.3 Ammonia Production

Most ammonia ($NH_3$) production processes emit carbon dioxide through the catalytic reformation of fossil fuels.

Ammonia is produced through a reaction between hydrogen and nitrogen gases. While nitrogen is available from the atmosphere, hydrogen must be supplied from a specialized source. Hydrogen can be obtained from the catalytic reformation of natural gas or other fossil fuels. Nearly all of the ammonia produced in the United States uses catalytic steam to reform natural gas. Additional sources include the reformation of other fossil fuels and byproduct hydrogen streams, as from the electrolysis of brine to produce chlorine or sodium hydroxide.[71]

Carbon dioxide emission rates are influenced by a number of factors, including the carbon content of the reformed fossil fuel, plant operating characteristics, and the type of emissions control technology or carbon dioxide recovery mechanisms, if any, employed at the plant (e.g., capture and use of carbon dioxide in the production of urea). Accordingly, direct measurement of emissions, for instance, via continuous emission monitoring, is the most accurate method for estimating emissions from ammonia production. Estimates based on direct measurements of emissions, including CEM and periodic direct measurements will be assigned a rating of "A."

In the absence of direct measurement, there are a number of methods reporters can use to estimate emissions. The following estimation methods assume that all of the carbon contained in the feedstock fuel is released directly to the atmosphere.[72] Ratings for these estimates will depend on the data that are available.

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[71] Ammonia production using hydrogen from byproduct streams does not generate any carbon dioxide emissions.

[72] These methods are derived from the following sources, which should be used as references:
- Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (1997), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.
- World Resources Institute/World Business Council for Sustainable Development, *Greenhouse Gas Protocol Initiative* (2001), web site: www.ghgprotocol.org/DocRoot/PjFmTPgYDO3NsNafGrfn/co2-amnomia.pdf.

Reporters can estimate carbon dioxide emissions using a mass balance approach based on the carbon content and consumption data for the feedstock fuel used to produce ammonia. Carbon dioxide emissions are estimated using the following equation:

$$CO_2 \text{ emissions} = \text{Consumption}_{\text{Feedstock fuel}} * \text{Carbon content}_{\text{Feedstock fuel}} * CO_2 / \text{carbon ratio}$$

**Where:**

**$CO_2$ / Carbon ratio = 44/12**

Emission estimates using a known value for the carbon content of the feedstock fuel[73] will be assigned a quality rating of "B." If plant-specific data are not available, reporters can use the default carbon content values for pipeline quality natural gas in the United States, provided in Table 1.E.5 below.[74]

### Table 1.E.5. Carbon Dioxide Emissions Coefficients for U.S. Natural Gas

| HHV Btu Content per Standard Cubic Foot | Emissions Coefficient (metric tons per billion Btu) | |
|---|---|---|
| | $CO_2$ | Carbon |
| 975 – 1,000 | 54.01 | 14.73 |
| 1,000 – 1,025 | 52.91 | 14.43 |
| 1,025 – 1,050 | 53.06 | 14.47 |
| 1,050 – 1,075 | 53.46 | 14.58 |
| 1,075 – 1,100 | 53.72 | 14.65 |

**Source**: Energy Information Administration, *Documentation for Emissions of Greenhouse Gases in the United States 2003* (May, 2005), web site: www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf.

Emission estimates using these values will be assigned a rating of "B."

If plant-specific information is not available, reporters can use a default emissions factor of 1.26 tons carbon dioxide / ton ammonia produced.[75] Emission estimates based on this default value will be assigned a rating of "C."

Reporters estimating carbon dioxide emissions from ammonia production should ensure that the feedstock (usually natural gas) is not also treated as a source of combustion emissions, which would cause double counting.

Carbon dioxide generated by ammonia plants is sometimes captured for use as an industrial product (e.g., for urea, dry ice, or use in carbonated beverages). Any such emissions that are captured and sold or otherwise exported for use by a separate entity should not be reported by the capturing entity. If they are subsequently released, they should be reported by the entity in possession of the material at the time such gases are emitted. If carbon dioxide from ammonia

[73] Industrial natural gas is usually sold on a volumetric basis, and which is typically "corrected for" with a Btu adjustment factor. Reporters should be able to derive Btu content from this information.

[74] Derived from: Energy Information Administration, *Documentation for Emissions of Greenhouse Gases in the United States 2003* (May 2005), web site: www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf. Carbon coefficients for other fossil fuels are also provided in this document.

[75] U.S. Environmental Protection Agency, *Synthetic Ammonia*, AP-42, 5th Ed., Vol. 1, Ch. 8 (1993), web site: http://www.epa.gov/ttn/chief/ap42/index.html.

production is captured and used by the same entity as an input to another industrial process, such as urea manufacturing, the carbon dioxide consumed should not be reported as an emission from ammonia production. Reporters should also be aware of the potential for fugitive emissions of methane from ammonia production, either through feedstock (i.e., natural gas) leaks, or alongside fugitive non-methane volatile organic compounds NMVOC emissions from the steam reforming process. Reporters should refer to applicable guidelines and ratings for estimating fugitive emissions as reported in the Oil and Natural Gas Industries subsection 1.E.4.2.2.

Ratings of methods for estimating carbon dioxide emissions from ammonia production are summarized in Table 1.E.6.

**Table 1.E.6. Rating of Estimation Methods for Carbon Dioxide Emissions from Ammonia Production**

| Estimation Method | Rating |
|---|---|
| Continuous emission monitoring or periodic direct measurement | A |
| Mass balance when carbon content of feedstock fuel is known | B |
| Mass balance using default carbon content value | B |
| Default emissions factor of 1.26 tons carbon dioxide per ton ammonia produced | C |

### 1.E.4.1.4 Cement Production

Cement manufacturing is the largest source of non-combustion, anthropogenic carbon dioxide emissions resulting from industrial processes. Cement production releases carbon dioxide both during the production of clinker (calcination carbon dioxide) and from discarded bypass and/or cement kiln dust (CKD).

#### 1.E.4.1.4.1 Carbon Dioxide Emissions from Clinker Production

Clinker production is the most significant source of greenhouse gas emissions during the production of cement.[76] Carbon dioxide is released when a calcium carbonate ($CaCO_3$)-rich substrate such as lime or chalk is heated, converting the calcium carbonate content to calcium oxide (CaO) and carbon dioxide ($CO_2$). This process is known as calcination. The calcium oxide is then exposed to a silica-containing material such as clay, leading to the formation of clinker. "Calcination carbon dioxide" can be measured in two ways: the clinker method or the cement method.

The "clinker method" is a mass balance approach based on the quantity of clinker produced.[77] Reporters can calculate a "calcination" emissions factor (tons carbon dioxide released from

[76] Portland cement, which has a 95-percent clinker fraction, is the most commonly produced type of cement, and is the type of cement toward which these guidelines are oriented. Any additional carbon dioxide emissions associated with the production of masonry cement would be accounted for under lime production and not under cement production.

[77] This method is derived from the following sources, which should be used as references:
- Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (1997), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.
- World Resources Institute/World Business Council for Sustainable Development, *Greenhouse Gas Protocol Initiative* (2001), web site: www.ghgprotocol.org/standard/tools.htm.

calcium carbonate per ton clinker produced) by multiplying the measured calcium oxide content of the clinker (as a percent) by the molecular ratio of carbon dioxide to calcium oxide (0.785):

**Calcination $CO_2$ Emissions Factor = CaO content * Molecular ratio of $CO_2$ to CaO**

**Where:**

| | | |
|---|---|---|
| **CaO Content** | **=** | **CaO content of Clinker (%)** |
| **Molecular Ratio of $CO_2$ / CaO** | **=** | **0.785** |

Multiplying this emissions factor by clinker production data will provide an estimate of carbon dioxide emissions from calcination:

**Calcination $CO_2$ Emissions = Calcination $CO_2$ Emissions Factor * Clinker Produced**

**Where:**

| | | |
|---|---|---|
| **Clinker Produced** | **=** | **Tons of Clinker produced** |

Estimates based on this approach will be assigned a rating of "A."

Similarly, magnesium carbonate ($MgCO_3$) in cement raw materials decomposes to magnesium oxide (MgO) and carbon dioxide ($CO_2$) during calcination. These emissions can be calculated by measuring the magnesium oxide content of the clinker.[78] Reporters can calculate a "magnesium" emissions factor (tons carbon dioxide released from magnesium carbonate per ton clinker produced) by multiplying the measured magnesium oxide content of the clinker (as a percent) by the molecular ratio of carbon dioxide to magnesium oxide (1.092):

**Magnesium $CO_2$ Emissions Factor = MgO content * Molecular ratio of $CO_2$ to MgO**

**Where:**

| | | |
|---|---|---|
| **MgO Content** | **=** | **MgO content of Clinker (%)** |
| **Molecular Ratio of $CO_2$ / MgO** | **=** | **1.092** |

Multiplying this emissions factor by clinker production data will provide an estimate of carbon dioxide emissions from the decomposition of $MgCO_3$:

**Magnesium $CO_2$ Emissions = Magnesium $CO_2$ Emissions Factor * Clinker Produced**

**Where:**

| | | |
|---|---|---|
| **Clinker Produced** | **=** | **Tons of Clinker produced** |

Estimates based on this information will be assigned a rating of "A."

[78] This method is derived from the following sources, which should be used as references:
- Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (1997), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.
- World Resources Institute/World Business Council for Sustainable Development, *Greenhouse Gas Protocol Initiative* (2001), web site: www.ghgprotocol.org

If the calcium oxide or magnesium carbonate content of the clinker is not known, a default emissions factor of 0.525 metric tons of carbon dioxide / metric ton clinker can be used.[79] Emission estimates using this default value will be assigned a rating of "B."

If the CaO content of the clinker is not known, carbon dioxide emissions can be estimated using another mass balance approach referred to as the "cement method."[80] The cement method relies on information about the composition and quantity of raw materials consumed (rather than the clinker produced), the quantity of clinker incorporated into the cement and the quantity of cement produced. If reporters have access to reliable information regarding the quantity of clinker in their cement and the composition of the raw materials used in its production, this method is as accurate as the clinker method. The data used to calculate an emissions factor are as follows:

**$CO_2$ Emissions per quantity cement produced = Clinker-to-cement ratio * Raw material-to-clinker ratio * $CaCO_3$ content * Molecular ratio of $CO_2$ to $CaCO_3$**

**Where:**

| | | |
|---|---|---|
| **Clinker-to-cement ratio** | **=** | **Tons of clinker / ton of cement** |
| **Raw material-to-clinker ratio** | **=** | **Tons of raw material / ton of clinker** |
| **$CaCO_3$ Content** | **=** | **Lime content of the raw materials (%)** |
| **Molecular Ratio of $CO_2$ / $CaCO_3$** | **=** | **0.44** |

Carbon dioxide emissions are estimated by multiplying this emissions factor by the total quantity of cement produced. Emission estimates using this approach in conjunction with plant-specific raw material composition and clinker fraction data will be assigned a rating of "A."

If plant-specific data regarding the clinker-to-cement ratio is not known, reporters can use default clinker and additive fraction values for different cement production mixes provided in Table 1.E.7.[81]

### Table 1.E.7. Clinker Composition Values for Non-Portland Blended Cement Types

| Cement Type | Percent Clinker | | | | |
|---|---|---|---|---|---|
| Additives (Pozzolan + Slag) in the Blended Cement (percent) | 10 | 20 | 30 | 40 | 75 |
| Clinker in the Cement Production Mix (percent) | 85 | 76 | 66 | 57 | 24 |

Source: Intergovernmental Panel on Climate Change, *Good Practice Guidance and Uncertainty Management for National Greenhouse Gas Inventories* (2000).

[79] This value is taken from the WRI/WBCSD's *Clinker-based Methodology for Calculating $CO_2$ from the Production of Cement* and accounts for $CO_2$ emissions from both the $CaCO_3$ and $MgCO_3$ content of the raw materials.

[80] This method is derived from the U.S. Environmental Protection Agency, *ClimateLeaders Greenhouse Gas Inventory Protocol Core Module Guidance – Direct Emissions from Cement Sector*, web site: www.epa.gov/climateleaders/docs/cement.pdf.

[81] Reporters using cement production mixes in between the values provided in Table 1.E.7 can estimate their "Clinker in the Cement Production Mix" value by interpolation (e.g. a reporter with an "Additive in the Blended Cement" value of 25 percent can assume a 71 percent "Clinker in the Cement Production Mix" value).

Estimates that use these values will be assigned a rating of "B."

If reliable data on the quantities and composition of the raw materials used are not available, reporters can use a default emissions factor of 0.499 tons carbon dioxide / ton cement produced.[82] Emission estimates relying on this default emissions factor will be assigned a rating of "C."

#### 1.E.4.1.4.2 Carbon Dioxide Emissions from Discarded Bypass/Cement Kiln Dust

During the production of cement, some of the raw materials entered into the kiln may not be converted into clinker, generating what is known as cement kiln dust (CKD). CKD can either be "recycled" back into the clinker production process, or used for some other application (e.g., as a soil liming agent, or in road bases). CKD that is landfilled or discarded instead of being re-used can be another source of carbon dioxide emissions. Emissions from discarded CKD should not be included in cement manufacturers' emission inventories, provided it is discarded outside of the entity's organizational boundaries. If the discarded CKD eventually lead to emissions, such emissions should be included in the inventory of the entity in possession of the material at the time the emissions occur.

Estimates based on direct measurements of emissions will be assigned a rating of "A." Reporters with plant-specific clinker emissions factors (see above) and the data on the portion of CKD that is calcined should consult the WRI protocol for details on estimating emissions from discarded CKD.[83] Estimates based on this methodology are rated "B."

If specific data on CKD composition and quantities are not available, reporters can assume carbon dioxide emissions from discarded CKD are equal to 2 percent of the carbon dioxide emissions from clinker production.[84] Estimates based on this method will be assigned a rating of "C."

Ratings of methods for estimating carbon dioxide emissions from cement production are summarized in Table 1.E.8.

### Table 1.E.8. Rating of Estimation Methods for Carbon Dioxide from Cement Production

| Estimation Method | Rating |
|---|---|
| **Carbon Dioxide Emissions From Clinker Production** | |
| Mass balance, clinker method, based on measured calcium oxide content of clinker | A |
| Clinker method based on measured magnesium oxide content of clinker | A |
| Default emissions factor (includes emissions from CaO and MgO) | B |
| Mass balance, cement method, based on plant-specific raw material data and clinker content of cement | A |
| Default clinker and additive fraction values for appropriate cement production mix | B |

[82] Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (1997) web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.
[83] Available at web site www.ghgprotocol.org/DocRoot/T9ZLuFseFvcAUYTDN1mO/co2-cement-epa.pdf.
[84] Intergovernmental Panel on Climate Change, *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Emission Inventories* (2000), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*.

| | |
|---|---|
| Default emissions factor of 0.499 tons carbon dioxide per ton cement produced | C |
| **Carbon Dioxide Emissions From Discarded Bypass/Cement Kiln Dust** | |
| Direct measurement | A |
| Plant-specific clinker emissions factors and data on portion of CKD that is calcined | B |
| Inference based on discarded CKD value, assumed equal to two percent of $CO_2$ from clinker production | C |

### 1.E.4.1.5 Hydrogen Production

Hydrogen production is similar, in many respects, to ammonia production. As in the case of ammonia, a hydrocarbon feedstock (usually natural gas) is reformed into a carbon monoxide-hydrogen synthesis gas. In this case, the hydrogen is separated and used for other purposes (usually to boost light product output in oil refineries; occasionally directly as a transportation fuel).

For the purposes of the Voluntary Reporting Program, reporters should only treat carbon dioxide produced as a byproduct of hydrogen production as an industrial process emission if it is emitted into the atmosphere. Direct measurement of carbon dioxide emissions from this source would be rated "A." Reporters may also use mass balance calculations from the feedstock use of fossil fuels to calculate emissions from this source.[85] Estimates based on mass balance calculations will be assigned a rating of "A."

Ratings of methods for estimating emissions from hydrogen production are summarized in Table 1.E.9.

**Table 1.E.9. Rating of Estimation Methods for Carbon Dioxide Emissions from Hydrogen Production**

| Estimation Method | Rating |
|---|---|
| Direct measurement | A |
| Mass balance based on feedstock use of fossil fuels | A |

### 1.E.4.1.6 Iron and Steel Production

This section covers emissions from the production of iron and steel from two types of facilities: large, integrated primary iron and steel plants; and smaller, primary plants. Integrated plants have coking, smelting and refining capabilities, allowing them to produce iron and steel from iron ore and raw coal. Smaller primary plants typically produce iron and steel with coke that is imported from external coking plants.[86]

All iron/steel plants use a blast furnace to produce pig iron, also known as crude iron. In the furnace, raw iron ore is heated in the presence of carbon and oxygen, reducing it to molten pig iron. Coke is the usual source of carbon for this process (though coal and natural gas are also used) and is consumed both as a fuel and as a source of carbon. Pig iron production is aided in most plants by the addition of a carbonate flux, such as limestone or dolomite.

[85] For guidance on estimating emissions using mass balance based on the carbon content of feedstock fuels, refer to Section 1.E.4.1.3, "Ammonia Production."
[86] The coke generated by integrated plants and coking facilities is identical.

Reducing the carbon content of crude iron through oxidation produces steel. Low-carbon steels are produced in basic oxygen furnaces (BOF), while high-carbon and alloy steels are produced in electric arc furnaces (EAF), induction and open-hearth furnaces.

The majority of carbon dioxide emissions from iron and steel production are generated during the consumption of the reducing agent, and of additives (typically plastics) used to reduce the quantity of reducing agent used. Consumption of carbonate fluxes is also a significant source of carbon dioxide, but these emissions should be calculated using the methods outlined under "Limestone and Dolomite Use."

In general, the most accurate estimates of emissions from iron and steel producing facilities will include mass balance calculations of emissions from the consumption of reducing agents and additives, and the conversion of iron to steel, corrected for the quantity of carbon contained in carbon-bearing products exported from the facility. If it is not possible to account for all of these emissions using plant-specific data, default values are provided.

### 1.E.4.1.6.1 Carbon Dioxide Emissions from Reducing Agent Consumption

Reducing agent consumption is the primary carbon dioxide emitting process in iron and steel production. Carbon dioxide emissions from reducing agent consumption can be estimated by multiplying the mass of the reducing agent consumed by its carbon content (as a percent) by the molecular ratio of carbon dioxide to carbon (44/12):

$$CO_2\ \text{Emissions}_{\text{Reducing Agent}} = M_{\text{Reducing Agent}} * CC_{\text{Reducing Agent}} * (44/12)$$

**Where:**

| | | |
|---|---|---|
| $M_{\text{Reducing Agent}}$ | = | **mass of the reducing agent consumed, in tons** |
| $CC_{\text{Reducing Agent}}$ | = | **carbon content of the reducing agent (percent)** |
| **44/12** | = | **molecular ratio of carbon dioxide to carbon** |

Emission estimates using known values for the carbon content of the reducing agent will be assigned a rating of "A."

If specific data on the carbon content of the reducing agent used are not available, reporters can use the default emissions factors provided in Table 1.E.10.

**Table 1.E.10. Default $CO_2$ Emissions Factors for Various Reducing Agents**

| Reducing Agent | Emissions Factor (ton $CO_2$ / Ton reducing agent) |
|---|---|
| Coke from coal | 3.1 |
| Coal | 2.5 |
| Petroleum coke | 3.6 |

Source: Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories - Reference Manual* (1997) p. 2.26, Table 2-12.

Emission estimates using these default values will be assigned a rating of "B."

#### 1.E.4.1.6.2 Carbon Dioxide Emissions from Furnace Additives

Iron producers will sometimes introduce additives such as recycled plastic compounds to the blast furnace to reduce the quantity of coke used as a reducing agent. Emissions from those additives can be estimated using the following general equation:

$$CO_2 \text{ emissions}_{\text{additives}} \text{ (tons)} = \text{Mass}_{\text{additive}} \text{ (tons)} * \text{Emissions factor}_{\text{additive}} \text{ (ton } CO_2 \text{ / ton additive)}$$

Reporters can use the default emissions factors for common reducing agent additives provided in Table 1.E.11.

**Table 1.E.11. Default Emissions Factors for Furnace Additives**

| Additive | Ton $CO_2$ / Ton additive |
|---|---|
| PVC | 1.62 |
| PET | 2.24 |
| PE | 2.85 |

Source: World Resources Institute / World Business Council for Sustainable Development, *Calculating $CO_2$ Emissions from the Production of Iron and Steel,* Guidance Section.

Emission estimates using these default values will be assigned a rating of "A."

#### 1.E.4.1.6.3 Carbon Dioxide Emissions from the Conversion of Iron to Steel

Carbon dioxide is released when high-carbon pig iron is reduced to lower-carbon steel. If data on the carbon content of the pig iron and steel produced are available, reporters should estimate these emissions.[87] Carbon dioxide emissions can be estimated by multiplying the difference between the quantities of carbon contained in the pig iron and in the steel products by the mass ratio of carbon dioxide to carbon (44/12), as in the following equation:

$$CO_2 \text{ Emissions}_{\text{Pig iron}} = (\text{Carbon Content}_{\text{Pig Iron}} - \text{Carbon Content}_{\text{Steel}}) * (44/12)$$

Emission estimates based on plant-specific carbon contents will be assigned a rating of "A."

If specific values for the carbon contents of the produced metals are unavailable, default emissions factors provided in Table 1.E.12 may be used.

**Table 1.E.12. Default Carbon Content Values for Various Metals**

| Metal | Carbon Content (percent) |
|---|---|
| Ore | Approximately 0 |
| Internationally traded crude (pig) iron | Approximately 4 |
| Cast iron products | Approximately 4 |
| Steel produced | 0.004 |

Source: World Resources Institute / World Business Council for Sustainable Development, *Calculating $CO_2$ Emissions from the Production of Iron and Steel,* Guidance Section.

[87] This discussion applies to all pig iron that is reduced to steel, regardless of whether the pig iron is produced on-site or purchased.

Emission estimates using these default values will be assigned a rating of "B."

### 1.E.4.1.6.4 Carbon Dioxide Emissions from Graphite Electrodes in EAF Furnaces

Facilities that produce steel using EAF furnaces should estimate carbon dioxide emissions from the consumption of graphite electrodes. Reporters can estimate those emissions using the following emissions factor approach:

$$CO_2 \text{ Emissions}_{\text{graphite electrodes}} \text{ (tons)} = \text{Mass}_{\text{graphite electrodes}} \text{ (tons)} * \text{Emissions Factor}_{\text{graphite electrodes}} \text{ (tons } CO_2 \text{ / ton electrode)}$$

Emission estimates using plant-specific graphite electrode emissions factors will be assigned a rating of "A."

If plant-specific electrode emissions factors are not available, reporters can estimate emissions from electrode consumption by using a default value of 1.5 kg $CO_2$ per ton steel produced in EAF furnaces.[88] This method will be assigned a rating of "B."

### 1.E.4.1.6.5 Default Method for Estimating Carbon Dioxide Emissions from Iron and Steel Production – All Processes

If reporters do not have access to the data required to estimate emissions from the various sources specified above, they can use a default emissions factor of 1.75 metric tons carbon dioxide per metric ton of steel,[89] which includes emissions from all of these sources for integrated steel facilities. Estimates based on these values will be assigned a rating of "C."

Ratings of methods for estimating emissions from iron and steel production are summarized in Table 1.E.13.

**Table 1.E.13. Rating of Estimation Methods for Carbon Dioxide Emissions from Iron and Steel Production**

| Estimation Method | Rating |
|---|---|
| **Carbon Dioxide Emissions From Reducing Agent** | |
| Plant-specific data on reducing agent consumption and its carbon content | A |
| Default reducing agent emissions factors | B |
| **Carbon Dioxide Emissions From Furnace Additives** | |
| Mass balance using default furnace-additive emissions factor | A |
| **Carbon Dioxide Emissions From the Conversion of Iron to Steel** | |
| Mass balance based on plant-specific carbon content of pig iron minus plant-specific carbon content of steel | A |
| Mass balance based on default carbon content values | B |

[88] Value taken from Intergovernmental Panel on Climate Change, *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Emission Inventories* (2000), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*.

[89] Value taken from: World Resources Institute / World Business Council for Sustainable Development, *Greenhouse Gas Protocol Initiative - Calculating $CO_2$ Emissions from the Production of Iron and Steel - Automated Worksheets* web site: www.ghgprotocol.org/.

| Carbon Dioxide Emissions From Graphite Electrodes in EAF Furnaces | |
|---|---|
| Mass Balance using plant-specific graphite electrode emissions factors | A |
| Mass Balance using default emissions factor of 1.5 kg $CO_2$ per ton steel produced | B |
| **Carbon Dioxide Emissions - All Processes** | |
| Production times default emissions factor of 1.75 tons $CO_2$ per ton of steel | C |

### 1.E.4.1.7 Lime Production

Lime production refers to the manufacture of high calcium lime, dolomitic lime, and hydraulic lime. In the production of calcium lime and hydraulic lime, carbon dioxide is released by thermally decomposing, or "calcining," calcium carbonate ($CaCO_3$) into lime (CaO) and carbon dioxide ($CO_2$). Dolomitic lime is produced by the calcination of dolomite ($CaCO_3 \cdot MgCO_3$). Carbon dioxide released from the production of lime in the Kraft pulping process need not be included in emission inventories since the carbon originates in wood and is considered to be biogenic.

Carbon dioxide emissions from lime production can be calculated using a mass balance method. The basic stoichiometry of the calcination process is shown below:

*High-Calcium and Hydraulic Lime*

$$\mathbf{CaCO_3 + Heat \rightarrow CaO + CO_2}$$

or

*Dolomitic Lime*

$$\mathbf{2\ CaCO_3 \cdot MgCO_3 + Heat \rightarrow 2\ CaO \cdot MgO + 4\ CO_2.}$$

The stoichiometric weight ratios of carbon dioxide to calcium oxide and carbon dioxide to magnesium oxide are provided in Table 1.E.14.

### Table 1.E.14. Stoichiometric Weight Ratio of $CO_2$ to CaO and $CO_2$ to MgO

| Lime Component | Stoichiometric Weight Ratio |
|---|---|
| Calcium oxide (CaO) | 0.7848 |
| Magnesium oxide (MgO) | 1.0918 |

Source: National Lime Association, *$CO_2$ Emissions Calculation Protocol for the Lime Industry: English Units Version*, February 2, 2005 Revision, 17 pp.

Reporters can calculate an emissions factor for each type of quicklime and each type of calcined byproduct/waste produced by multiplying the stoichiometric weight ratios in Table 1.E.14 by the CaO content or for dolomitic lime, the MgO content, of the lime (as a percent by mass) produced:

$$\textbf{Emissions Factor} = (\%\ \textbf{Total CaO} * \textbf{SWR}_{CO2/CaO}) + (\%\ \textbf{Total MgO} * \textbf{SWR}_{CO2/MgO})$$

**Where:**

| | | |
|---|---|---|
| **Emissions Factor** | **=** | **tons $CO_2$ / ton high calcium, dolomitic or hydraulic lime produced, as appropriate** |
| **% Total CaO** | **=** | **CaO content of lime as a percent by mass** |

| | | |
|---|---|---|
| **% Total MgO** | **=** | **MgO content of lime as a percent by mass** |
| **$SWR_{CO2/CaO}$** | **=** | **Stoichiometric weight ratio of $CO_2$ to CaO (0.7848)** |
| **$SWR_{CO2/MgO}$** | **=** | **Stoichiometric weight ratio of $CO_2$ to MgO (1.0918)** |

Total carbon dioxide emissions can then be calculated by multiplying the emissions factors derived above by the respective quantities of each type of quicklime and calcined byproduct/waste produced:

**Total Emissions = Quantity Quicklime or Calcined Byproduct/Waste Produced * Emissions Factor**

Emission estimates using measured, site-specific values will be assigned a rating of "A."

If reporters do not have the data required to estimate their own emissions factor, they can use the default emissions factors provided in Table 1.E.15.

### Table 1.E.15. Default $CO_2$ Emissions Factors for Lime Production

| Lime Type | Default Emissions Factor (tons $CO_2$ / ton lime) |
|---|---|
| High Calcium | 0.75 |
| Dolomitic | 0.86 |
| Hydraulic | 0.59 |

Source: Intergovernmental Panel on Climate Change, *Good Practice Guidance and Uncertainty Management for National Greenhouse Gas Inventories* (2000), p. 3.22, Table 3.4.

Emission estimates using these default values will be assigned a rating of "B."

Ratings of methods for estimating emissions from lime production are summarized in Table 1.E.16.

### Table 1.E.16. Rating of Estimation Methods for Carbon Dioxide Emissions from Lime Production

| Estimation Method | Rating |
|---|---|
| Mass balance using limestone production emissions factor based on measured lime purity value | A |
| Mass balance using IPCC default emissions factor | B |

### 1.E.4.1.8 Limestone and Dolomite Use

Lime production involves subjecting limestone or dolomite to high temperatures, which converts it to lime by releasing carbon dioxide. This process is known as calcination, or calcining; see subsection 1.E.4.1.7, "Lime Production," just above. The following discussion is intended for use by industries other than lime producers that use limestone in processes that similarly involve its heating.

The method for estimating carbon dioxide emissions from limestone use is largely analogous to that used to estimate emissions from lime production. The primary difference between the

methods is that estimates for lime production are based on the quantity of the calcium-bearing product (limestone [$CaO_3$] or dolomite [$CaO \cdot MgO$]), whereas emissions from limestone and dolomite use are estimated using the quantity of calcium-bearing raw materials (limestone or dolomite).

Carbon dioxide emissions from limestone and dolomite use can be estimated with a mass balance approach. As is the case with limestone production, an emissions factor can be calculated using known stoichiometric ratios, activity data and fractional purity values. The most accurate emissions factor is calculated using plant-specific data on the percent of $CaCO_3$ (limestone) or $CaCO_3 \cdot MgCO_3$ (dolomite) in the raw materials consumed, called fractional purity. If the fractional purity is known, it can be multiplied by the default emissions factors in Table 1.E.17 to derive a plant-specific emissions factor. Emission estimates using these data will be assigned a rating of "A." If specific data about the fractional purity of the raw materials are not available, reporters can use the default emissions factors listed in Table 1.E.17, below, which assume 100 percent fractional purity of the raw materials.

### Table 1.E.17. Default $CO_2$ Emissions Factors for Limestone and Dolomite Use

| Raw Material | Default Emissions Factor |
|---|---|
| Limestone ($CaCO_3$) | 477 kg $CO_2$ / metric ton limestone |
| Dolomite ($CaCO_3 \cdot MgCO_3$) | 440 kg $CO_2$ / metric ton dolomite |

Source: Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories - Reference Manual* (1997) p. 2.10.

Estimates using these values will be assigned a rating of "B."

Ratings of methods for estimating emissions from limestone and dolomite use are summarized in Table 1.E.18.

### Table 1.E.18. Rating of Estimation Methods for Carbon Dioxide Emissions from Limestone and Dolomite Use

| Estimation Method | Rating |
|---|---|
| Mass balance using plant-specific emissions factor based on limestone and dolomite content of the raw material consumed | A |
| Mass balance using IPCC default emissions factor | B |

### 1.E.4.1.9 Methanol Production

Methanol production is similar to ammonia production (see section above), in that methanol production begins with reforming a hydrocarbon feedstock (usually natural gas) into a carbon monoxide-hydrogen synthesis gas. In this case, however, most of the carbon is embodied in the product ($CH_4O$). Methanol in the United States is mostly used as a gasoline additive, though there is also a large market for methanol as a chemical feedstock.

For the purposes of the Voluntary Reporting Program, incidental carbon dioxide emissions from methanol production should be reported as emissions, although the carbon embodied in the methanol itself should *not* be reported as an emission. The party that combusts the methanol is responsible for emissions of the carbon in the methanol. Methanol in the gasoline pool (either

directly or in the form of Methyl Tertiary Butyl Ether [MTBE]) is implicitly included in the emissions factor for motor gasoline, and is the responsibility of transportation sector users. See Part D, "Mobile Sources," for guidance on estimating emissions from transportation activities.

Direct measurement of carbon dioxide emissions from the production of methanol, possibly via continuous emission monitoring, would be rated "A." Reporters may use mass balance calculations (carbon content of feedstock less carbon content of methanol) to estimate incidental carbon dioxide losses/emissions from this source. Estimates based on mass balance calculations will be assigned a rating of "B."

Methanol production also yields small volumes of methane emissions. The IPCC provides a default emissions factor of two grams methane per kilogram of methanol produced.[90] Reporters may use these default factors when calculating methane emissions from methanol production and will be assigned a rating of "B." Reporters that are able to directly measure methane emissions during methanol production will receive an "A" rating.

Ratings of methods for estimating emissions from methanol production are summarized in Tables 1.E.19 and 1.E.20 below.

### Table 1.E.19. Rating of Estimation Methods for Carbon Dioxide Emissions from Methanol Production

| Estimation Method | Rating |
|---|---|
| Continuous emissions monitoring or other direct measurement | A |
| Mass balance accounting for carbon content of feedstock fuel minus carbon content of methanol | B |

### Table 1.E.20. Rating of Estimation Methods for Methane Emissions from Methanol Production

| Estimation Method | Rating |
|---|---|
| Direct measurement | A |
| Use of IPCC provided default factors | B |

### 1.E.4.1.10 Methane Emissions from the Production of Other Petrochemicals

The production of carbon black, ethylene, ethylene dichloride and styrene all generate small amounts of methane emissions. Default factors for estimating emissions from production of these petrochemicals are provided below in Table 1.E.21. Reporters may use these default factors when calculating methane emissions from methanol production and will be assigned a rating of "B." Reporters that are able to directly measure methane emissions during petrochemical production will receive an "A" rating.

[90] Intergovernmental Panel on Climate Change, *Revised IPCC Guidelines for National Greenhouse Gas Inventories* (1997), p.2.6. web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

### Table 1.E.21. Default Emissions Factors for Methane Emissions from Petrochemical Production

| Petrochemical | Methane Emissions (Grams per Kilogram of Production |
|---|---|
| Carbon Black | 11 |
| Ethylene | 1 |
| Ethylene Dichloride | 0.4 |
| Styrene | 4 |

Source: Intergovernmental Panel on Climate Change, *Revised IPCC Guidelines for National Greenhouse Gas Inventories* (1997), p.2.6. web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

### Table 1.E.22. Rating of Estimation Methods for Methane Emissions from Petrochemical Production

| Estimation Method | Rating |
|---|---|
| Continuous emissions monitoring or other Direct measurement | A |
| Use of IPCC provided default factors | B |

#### 1.E.4.1.11 Nitric Acid Production

Nitric acid ($HNO_3$) is a primary ingredient of certain nitrogen-based synthetic fertilizers. Other important applications include adipic acid production, production of explosives, metal etching, and processing of ferrous metals. The primary greenhouse gas emitted from the production of nitric acid is nitrous oxide ($N_2O$). Nitrous oxide is released during the high-temperature catalytic oxidation of ammonia ($NH_3$). In addition to nitrous oxide, this oxidation reaction can also generate smaller quantities of non-combustion oxides of nitrogen ($NO_x$).

Emissions from nitric acid production vary significantly from plant to plant. Factors that affect emission rates include process conditions, plant technology and design, whether or not an emission abatement technology is used, and the frequency with which that technology is employed.

Continuous emission monitoring (CEM) provides the most accurate estimate of plant emissions. Ideally, a CEM estimate will account for emissions from confined streams (e.g., pollutants in flue gas) as well as from uncontrolled streams. If information for pollutant levels in the uncontrolled streams is not available, monitoring confined streams alone will suffice. Emission estimates using CEM will be assigned a rating of “A.”

If CEM is not available, emissions can be estimated using an emissions factor (or emission rate) approach. For nitric acid plants, this approach must account for emission rates, the efficacy of abatement technologies and the frequency with which they are employed (where applicable). The most accurate emission rate estimates are based on direct, periodic measurements of plant emissions. Such measurements must be made whenever the plant undergoes a change that might alter emission rates. Emission estimates based on emissions factors derived from periodic direct measurements will be assigned a rating of “A.”

Reporters who are unable to acquire plant-specific emission information can use a default emissions factor of either 2 or 9.5 kg $N_2O$/metric ton nitric acid for plants with or without non-

selective catalytic reduction (NSCR) controls on $N_2O$ emissions, respectively.[91] Estimates based on default values developed through public or private consensus processes refereed by an organization such as the IPCC, U.S. EPA, or API will be assigned a "B" rating. Estimates based on other published default values will be assigned a rating of "C."

Ratings of methods for estimating emissions from nitric acid production are summarized in Table 1.E.23.

**Table 1.E.23. Rating of Estimation Methods for Nitrous Oxide Emissions from Nitric Acid Production**

| Estimation Method | Rating |
|---|---|
| Continuous emissions monitoring | A |
| Emissions factors based on direct, periodic measurement of plant emissions | A |
| Default emissions factors for uncontrolled and non-selective catalytic reduction control technologies from consensus-based published sources | B |
| Default emissions factors for uncontrolled and non-selective catalytic reduction control technologies | C |

### 1.E.4.1.12 Soda Ash Production and Use

#### 1.E.4.1.12.1 Soda Ash Production

There are four manufacturing processes employed to produce soda ash ($Na_2CO_3$): monohydrate carbonation, sesquicarbonate carbonation, direct carbonation, and the Solvay process. The Solvay process, which synthesizes soda ash from a series of materials and reactions, generates no direct carbon dioxide emissions. Emissions from stationary combustion and the use of coke to facilitate these processes, however, should be estimated and should be accounted for separately.[92]

The first three of these processes, which account for about 25 percent of world soda ash production, generate carbon dioxide emissions during the chemical transformation of the naturally occurring ore, trona, into Soda Ash. In the absence of direct measurements, reporters can use an emissions factor derived from the chemical reaction of the production of soda ash from trona:

$$\underset{\textit{(trona)}}{Na_2CO_3 \cdot NaHCO_3 \cdot 2H_2O} + \text{Heat} \rightarrow \underset{\textit{(soda ash)}}{3\ Na_2CO_3} + 5\ H_2O + CO_2.$$

One ton of carbon dioxide is generated for every 10.27 tons of trona consumed. Reporters can thus use the following carbon dioxide emissions factor for soda ash production:

$$\text{Emissions Factor}_{\text{Production}} = 0.097 \text{ tons } CO_2 \text{ / ton trona consumed}$$

Emission estimates based on this emissions factor will be assigned a rating of "A."

[91] Intergovernmental Panel on Climate Change. *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Emission Inventories* (2000), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*.
[92] See Part C, "Stationary Combustion."

#### 1.E.4.1.12.2 Soda Ash Use

Soda ash is used in a variety of industrial processes, including the manufacturing of glass, soap, detergents, and for flue gas desulfurization. Carbon dioxide emission rates from soda ash use are also based on stoichiometric ratios, which indicate that one molecule of carbon dioxide is emitted per molecule of soda ash consumed. Reporters can use the following carbon dioxide emissions factor for soda ash use, which is based on the molecular weight ratio of carbon dioxide to soda ash:[93]

$$\textbf{Emissions Factor}_{Use} = 0.415 \text{ tons } CO_2 \text{ / ton } Na_2CO_3$$

Emission estimates based on this emissions factor will be assigned a rating of "A."

Ratings of methods for estimating emissions from soda ash production and use are summarized in Table 1.E.24.

**Table 1.E.24. Rating of Estimation Methods for Carbon Dioxide Emissions from Soda Ash Production and Use**

| Estimation Method | Rating |
|---|---|
| **Soda Ash Production** | |
| Emissions factor based on production of soda ash from trona | A |
| **Soda Ash Use** | |
| Emissions factor based on molecular weight ratio of carbon dioxide to soda ash | A |

### 1.E.4.2 Energy

#### 1.E.4.2.1 Coal Mining

The principal greenhouse gas associated with coal mining is methane. Carbon dioxide and nitrous oxide are also emitted but in relatively small amounts. Methane is produced in the same geologic processes that produce coal, and therefore exists in varying degrees in its presence. The methane is stored in the coal pores (open spaces) and in the cracks and fractures within the coal bed.

Carbon dioxide emitted directly from the combustion of fossil fuels by mining equipment or indirectly from the consumption of electricity for mining activities should be estimated and reported according to the guidelines in Parts C and E, respectively. The methods outlined here focus exclusively on estimating methane emissions from coal mining.

The rank[94] of the coal determines the quantity of methane generated. Once generated, the amount of methane stored is controlled by the pressure and temperature of the coal seam and by other,

[93] Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (1997), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

[94] Rank is the degree to which peat has undergone thermal alteration to form coal. The higher the rank, the higher the carbon content, resulting in a higher heat value (HHV) per pound. Values for different coal ranks, measured in

less well-defined characteristics.[95] High coal ranks, such as anthracite and bituminous coal, contain more methane than low coal ranks, such as lignite (brown coal). Depth under ground is important, because it affects the pressure and temperature of the coal seam, which in turn determines how much methane is generated during coal formation. All else being equal, if two coal seams have the same rank, the deeper seam will hold larger amounts of methane because the pressure is greater at lower depths. As a result, the methane emissions factors for surface-mined coal are generally lower than for underground mining.

As coal is mined, the pressure surrounding the stored methane decreases, allowing much of it to be released into the operating coal mine (in the case of an underground mine) or into the atmosphere (in the case of a surface mine). The methane remaining in the coal pores is emitted when the coal is transported and pulverized for combustion.

#### 1.E.4.2.1.1 Processes that Produce Methane

To estimate the amount of methane emitted during coal mining, it is useful to segment the broader category of mining and processing into five distinct subcategories, as listed below.[96]

1) *Ventilation Systems in Underground Mines*. Methane in concentrations over 5 percent is explosive and presents a mortal danger to coal miners. To meet safety standards set by the Mine Safety and Health Administration (MSHA) requiring levels of methane concentration to be maintained well below the 5-percent threshold, mine operators use large fans to provide a steady airflow across the mine face and ventilate the mine shaft. These ventilation systems may release substantial quantities of methane in the fan exhaust.

2) *Degasification Systems in Underground Mines*. When the volume or concentration of gas in underground mines is too high to be practically reduced to safe levels by standard ventilation techniques, or if gas can be cost-effectively recovered for subsequent energy use, degasification systems are employed. Degasification may take place before mining or may take other forms, such as gob-wells or in-mine horizontal boreholes. Methane captured by degasification systems may be vented, flared, or recovered for energy.

3) *Surface Mines*. Because coal mined from the surface has formed at lower temperature and pressure than coal from underground mines, its methane content is lower. Further, because the coal is located near the surface, the associated methane has had greater opportunity to migrate to the atmosphere before mining.

4) *Post-Mining Emissions*. A portion of the methane emitted from coal mining comes from post-mining activities such as coal processing, transportation, and use. Coal processing

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Btu, are as follows: Anthracite: approximately 14,000; Bituminous 12,800 to 15,000; Sub-bituminous A: 12,600; Sub-bituminous B: 9,500 to 11,000; Sub-bituminous C: 8,000 to 9,500; Lignite: 3,000 to 8,000.

[95] Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (1997).

[96] Energy Information Administration, *Emissions of Greenhouse Gases in the United States 1998, Appendix A: Estimation Methods* (November 1999).

involves the breaking, crushing, and thermal drying of coal, making it acceptable for sale. Methane is released mainly because the increased surface area allows more methane to desorb from the coal. Transportation of the coal contributes to methane emissions, because methane desorbs directly from the coal to the atmosphere while in transit (e.g., in railroad cars).[97] Prior to combustion by end-users, coal may be pulverized, which also releases methane emissions.

5) *Methane Recovery for Energy*. In some cases methane is emitted from coal mines in sufficiently high volumes and concentrations to permit commercial recovery of the gas as pipeline gas, power generation fuel, or for mine site uses. Because coal mine methane recovered commercially is combusted, the quantities recovered are subtracted from estimates of total coal mine methane emissions.

#### 1.E.4.2.1.2 Emission Estimation Methods

Methane emissions from coal mines may be either directly monitored at the mine, or estimated based on the amount of coal produced and the type of mine being utilized. Where methane emissions are directly monitored, those direct measurements should be used first. Where direct monitoring does not exist, the indirect estimation methods detailed below should be used. Direct measurements will be more accurate than indirect measurements and would thus receive a higher rating, as indicated in Table 1.E.27, below.

Further discussion of the processes that produce methane and the associated methods to estimate emissions can be found in the IPCC's *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories,* EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2001* (2003), and EIA's *Documentation for Emissions of Greenhouse Gases in the United States 2002* (2004) (for complete references, see Section 1.E.4, above).

##### *1.E.4.2.1.2.1 Direct Measurements*

###### 1.E.4.2.1.2.1.1 Underground Mines with Detectable Emissions

Methane concentration and airflows from the ventilation systems of underground mines that have detectable methane concentrations are monitored on a quarterly basis by MSHA.[98] Underground mining operations with detectable emissions should therefore report their measured ventilation-related methane emissions directly, while also accounting for those emissions that are not included in the ventilation process (e.g., degasification and post-mining).

[97] It should be noted that some methane is also released from coal waste piles and abandoned mines. Coal waste piles are composed of rock and small amounts of coal that are produced during mining along with marketable coal. In some abandoned mines, methane can continue to be released from the surrounding strata for many years, although most available evidence indicates that methane flow rates decay rapidly once deep-mine coal production ceases.
[98] The Mining Safety and Health Administration (MSHA) records coal mine methane readings with concentrations of greater than 50 parts per million (ppm) methane. Readings below this threshold are considered non-detectable.

1.E.4.2.1.2.1.2 Degasification Emissions

The MSHA does not monitor degasification systems, but a mining operation may nevertheless collect these data, especially if the methane is subsequently captured and used for a productive purpose such as power generation or heat production. If direct measurements are available, they should be used first. In those cases where degasification emissions are not monitored, an indirect estimate should be made using methodologies described below.

*1.E.4.2.1.2.2 Indirect Estimation*

1.E.4.2.1.2.2.1 Degasification in Underground Mines

Total underground methane emissions are composed of ventilation system emissions and degasification system emissions. As mentioned previously, ventilation systems with detectable emission levels are monitored by MSHA directly, and some degasifications systems' emissions are monitored.

To estimate emissions from degasification systems that do not directly monitor emissions, an emissions factor based on total underground emissions (ventilation + gasification) is used. For coal mines employing gob wells and horizontal boreholes, it is assumed that degasification emissions account for 40 percent of the total methane liberated from the mine.[99] Therefore, the amount of methane emitted from the ventilation system should be multiplied by 1.667 to yield total (ventilation + degasification) emissions. Once total emissions are estimated, ventilated emissions can be subtracted from total emissions to derive estimated degasification emissions.

Some mining operations engage in advance degasification of underground coal seams prior to mining. The operator drills wells and extracts methane from the coal seam, in some cases years before the seam is actually mined. The extracted methane is often captured and sold commercially.

Captured gas, or its byproduct, is recorded as an emission in the inventory of the entity in possession of the gas at the time of its release into the atmosphere. If the methane is combusted, the carbon dioxide emissions from the combustion are considered an emission in the year of combustion. If the methane is vented, it is considered a methane emission in the year of venting.

1.E.4.2.1.2.2.2 Surface Mines and Post-Mining Operations

Because emissions from U.S. surface mines and from post-mining operations, whether underground or surface, are not systematically measured, estimates must be used instead. To estimate methane emissions from surface mines and post-mining operations, reporters can multiply the amount of coal produced at a given mine in one reporting year times a region-specific emissions factor (Table 1.E.25), as shown in the following equation. To convert from volume to mass, the density of methane at 20 degrees Celsius and 1 atmosphere of pressure should be used: 0.418 pounds per cubic foot.

[99] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2001, Appendix F*, EPA 430-R-03-004 (April 2003).

**Volume of Methane Produced = Mass of Coal Produced * $CH_4$ Volumetric Emissions Factor**

The surface mining emissions factor is estimated as twice the *in situ*[100] methane content in the basin, and the post-mining emissions factor is estimated to be 32.5 percent of the *in situ* methane content in the basin. Region-specific emissions factors are listed in Table 1.E.25, and coal basins and states are presented in Table 1.E.26.[101]

### Table 1.E.25. Coal Surface and Post-Mining Methane Emissions Factors ($ft^3$/short ton)

| Basin | Average *in situ* Content | | Factors | | |
|---|---|---|---|---|---|
| | Surface | Underground | Surface Mine | Post-Mining Surface | Post Mining Under-ground |
| Northern Appalachia | 59.5 | 138.4 | 119.0 | 19.3 | 45.0 |
| Central Appalachia (WV) | 24.9 | 136.8 | 49.8 | 8.1 | 44.5 |
| Central Appalachia (VA) | 24.9 | 399.1 | 49.8 | 8.1 | 129.7 |
| Central Appalachia (E KY) | 24.9 | 61.4 | 49.8 | 8.1 | 20.0 |
| Warrior | 30.7 | 266.7 | 61.4 | 10.0 | 86.7 |
| Illinois | 34.3 | 64.3 | 68.6 | 11.1 | 20.9 |
| Rockies (Piceance Basin) | 33.1 | 196.4 | 66.2 | 10.8 | 63.8 |
| Rockies (Unita Basin) | 16.0 | 99.4 | 32.0 | 5.2 | 32.3 |
| Rockies (San Juan Basin) | 7.3 | 104.8 | 14.6 | 2.4 | 34.1 |
| Rockies (Green River Basin) | 33.1 | 247.2 | 66.2 | 10.8 | 80.3 |
| Rockies (Raton Basin) | 33.1 | 127.9 | 66.2 | 10.8 | 41.6 |
| N. Great Plains | 5.6 | 15.8 | 11.2 | 1.8 | 5.1 |
| West Interior (Forest City, Cherokee Basins) | 34.3 | 64.3 | 68.6 | 11.1 | 20.9 |
| West Interior (Arkoma Basin) | 74.5 | 331.2 | 149.0 | 24.2 | 107.6 |
| West Interior (Gulf Coast Basin) | 33.1 | 127.9 | 66.2 | 10.8 | 41.6 |
| Northwest (AK) | 5.6 | 160.0 | 11.2 | 1.8 | 52.0 |
| Northwest (WA) | 5.6 | 47.3 | 11.2 | 1.8 | 18.9 |

Sources: U.S. Bureau of Mines, "Results of the Direct Method Determination of the Gas Contents of U.S. Coal Basins," Circular 9067 (1986); U.S. Department of Energy, *Methane Recovery from Coalbeds: A Potential Energy Source*, DOE/METC/83-76 (1983); and Gas Research Institute, "A Geologic Assessment of Natural Gas from Coal Seams," Topical Reports (1986-1988).

### Table 1.E.26. Coal Basins and States

| Basin | State |
|---|---|
| Northern Appalachia Basin | Maryland, Ohio, Pennsylvania, West Virginia North |
| Central Appalachia Basin | Kentucky East, Tennessee, Virginia, West Virginia South |
| Warrior Basin | Alabama, Mississippi |
| Illinois Basin | Illinois, Indiana, Kentucky West |
| S. West / Rockies Basin | Arizona, California, Colorado, New Mexico, Utah |
| N. Great Plains Basin | Montana, North Dakota, Wyoming |
| West Interior Basin | Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, |

[100] *In situ* - in the seam prior to mining

[101] For additional information on the location of coal basins and state lines, reporters should consult the USGS Coal Resources web site: http://energy.cr.usgs.gov/coal/index.htm.

| | |
|---|---|
| | Texas |
| Northwest Basin | Alaska, Washington |

Source: U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2003* (April 15, 2005).

1.E.4.2.1.2.2.3 Accounting for Underground Mines Without Detectable Emissions from Ventilation Systems

Methane concentrations in ventilation air below 0.1 percent are undetectable with the measurement equipment used by MSHA, although MSHA requires all active mines (including those with undetectable methane levels) to vent at a minimum rate of 3,000 cubic feet of air per minute. Operators with mines that show undetectable levels of methane concentration in ventilation air should thus calculate their ventilation emissions by multiplying a flow rate of 3,000 cubic feet per minute by an assumed methane concentration of 0.05 percent to derive a methane emissions flow rate.[102] Reporters can convert the flow rate to an annual emissions estimate with the following formula:

**Annual $CH_4$ emissions = Ventilation flow rate * $CH_4$ concentration * Min/Hour * Hours/Year**

that is,

**Annual $CH_4$ emissions = 3,000 $ft^3$/min * 0.05% $CH_4$ * 60 * 8760 = 788,400 $ft^3$ $CH_4$**

### 1.E.4.2.1.3 Methane Recovery for Energy

Any mining operation that captures or combusts methane and prevents its emission into the atmosphere (usually for combustion in power or heat generation) should ensure that total emissions account for captured methane and carbon dioxide emissions from combustion. The captured methane should not be counted in the inventory but the carbon dioxide from combusting the captured methane should be counted in the inventory of the entity in possession of the methane at the time of its combustion, following the guidance in Part C, "Stationary Combustion."

If direct measurements exist, then these should be used to determine the quantity of captured or combusted methane emissions. If direct measurements do not exist, then estimates can be made based on records of methane usage or sale to another entity. For example, if used for electricity generation, the amount of electricity produced, along with information about the generator, can be used to estimate the amount of methane consumed.

### 1.E.4.2.1.4 Emissions Summation

For underground mines, the total methane emissions that should be reported are:

1. Ventilation emissions from mines with detectable methane concentrations (directly measured).

[102] U.S. Environmental Protection Agency, *Anthropogenic Methane Emissions in the United States: Estimates for 1990: Report to Congress*, EPA 430-R-93-003 (April 1993), p. 3-11.

2. Degasification emissions (directly measured where possible; otherwise using default emissions factor based on measurements of ventilation emissions).
3. Post-mining operations (using default emissions factor based on mass of coal produced).
4. Estimation from mines with undetectable methane concentrations (using indirect estimate based on MSHA regulatory minimums).
5. Recovered methane emissions (directly measured where possible; otherwise using estimates based on usage or sales).

For surface mines, the total methane emissions that should be reported are:

1. Surface mining (using default emissions factor based on mass of coal produced).
2. Post-mining operations (using default emissions factor based on mass of coal produced).

Ratings of methods for estimating emissions from coal mining operations are summarized in Table 1.E.27.

**Table 1.E.27. Rating of Estimation Methods for Methane Emissions from Coal Mining (all sources)**

| Estimation Method | Rating |
|---|---|
| Direct measurement | A |
| Direct measurement augmented by indirect estimates based on default emissions factors | B |
| Indirect estimates based on default emissions factors | C |

### 1.E.4.2.2 Oil and Natural Gas Industries

The oil and natural gas industries are multifaceted industries that generate substantial quantities of greenhouse gas emissions from a variety of sources during production, processing, transportation, and distribution activities. Methods for estimating emissions from oil and natural gas activities are quite varied. Reporters are likely to employ all of the available estimation methods at some point if attempting to accurately and comprehensively estimate emissions from either industry in their entirety. Due to the extensive nature of emission sources and estimation methods, this section does not attempt to exhaustively enumerate methods for estimating greenhouse gas emissions from the oil and natural gas industries. Instead, reporters should use this section as a guide to the sources of emissions in these industries and the methods available to estimate them. Reporters should plan on referencing established, published authorities for details on estimation methods.[103]

[103] In addition to the sources listed above in Section 1.E.4, reporters should consult the following:
- International Petroleum Industry Environmental Conservation Association, *Petroleum Industry Guidelines for Reporting Greenhouse Gas Emissions* (2003), web site: www.ipieca.org/downloads/climate_change/GHG_Reporting_Guidelines.pdf.
-U.S. Environmental Protection Agency/GRI, *Methane Emissions from the Natural Gas Industry, Volume 1: Executive Summary*, EPA-600/R-96-080a (1996), prepared by M. Harrison, T. Shires, J. Wessels, and R. Cowgill, eds. (Radian International LLC for National Risk Management Research Laboratory, Air Pollution Prevention and Control Division, Research Triangle Park, NC), web site: www.epa.gov/gasstar/pdf/emissions_report/1_executiveummary.pdf.

Types of emission from these industries include process emissions, fugitive emissions, and emissions from stationary combustion.[104] The majority of these emissions are fugitive emissions. Common sources of fugitive emissions include exploration, handling, processing, production, storage, transportation, non-productive combustion (e.g., flaring[105]), and maintenance and turnaround activities, both scheduled and unscheduled. Process vents and non-combustion stacks are another common source of emissions from the natural gas industry. In contrast to fugitive emissions, those sources tend to be concentrated and relatively easy to identify.

Methane is the principal non-combustion greenhouse gas emitted by both the natural gas and the oil industries. The majority of emissions from the oil industry are fugitive methane emissions from production processes. As the principal component of natural gas, methane emissions are associated with nearly all aspects of the natural gas industry.

Carbon dioxide emissions can be emitted in significant quantities from a limited number of processes, such as sour gas processing, or in instances where natural gas streams are particularly rich in carbon dioxide. Nitrous oxide is also emitted from a number of activities, but usually in relatively low concentrations.

Emission estimation methods for the oil and natural gas industries vary widely in their scope, accuracy and involvement. As such, the method chosen by reporters will depend largely on the data, resources, time, and money available to them. Due to the large number and diversity of activities associated with each industry, the IPCC recommends disaggregating overall activities into subcategories and estimating emissions separately for each, as appropriate to their level of emissions and the resources available for each. Table 1.E.28 shows the industry segments and subcategories identified by the IPCC.

### Table 1.E.28. IPCC Categorization of Segments and Subcategories of the Natural Gas and Oil Industries

| Industry Segment | Subcategories |
|---|---|
| Wells | Drilling<br>Testing<br>Servicing |
| Gas Production | Dry Gas<br>Sweet Gas<br>Sour Gas |
| Gas Processing | Sweet Gas Plants<br>Sour Gas Plants<br>Deep-cut Extraction Plants |
| Gas Transmission and Storage | Pipeline Systems<br>Storage Facilities |

[104] Emissions associated with the combustion or use of petroleum-based products are not addressed in this section. Reporters should refer to Part C, "Stationary Combustion," and relevant sections within this Part to estimate these emissions.

[105] Flaring presents a unique situation in the oil and natural gas industries. While the majority of emissions from flaring result from combustion, flaring also releases significant quantities of non-combusted gases. According to the IPCC's *Good Practice Guidance* and *Revised 1996 IPCC Guidelines*, these releases should be accounted for as fugitive emissions.

| | |
|---|---|
| Gas Distribution | Rural Distribution<br>Urban Distribution |
| Liquefied Gases Transport | Condensate<br>Liquefied Petroleum Gas (LPG)<br>Liquefied Natural Gas (LNG) |
| Oil Production | Conventional Oil<br>Heavy Oil - Primary Production<br>Heavy Oil - Enhanced Production<br>Bitumen<br>Synthetic Crude Oil from Oil Sands<br>Synthetic Crude Oil from Oil Shales |
| Oil Upgrading | Bitumen<br>Heavy Oil |
| Waste Oil Reclaiming | None |
| Oil Transport | Marine<br>Pipelines<br>Tanker Trucks and Rail Cars |
| Oil Refining | Heavy Oil<br>Conventional and Synthetic Crude Oil |

Source: Intergovernmental Panel on Climate Change, *Good Practice Guidance and Uncertainty Management for National Greenhouse Gas Inventories* (2000).

The most comprehensive approach to estimating emissions from the natural gas and oil industries is to use a rigorous, site-specific, bottom-up estimate that accounts for emissions from each of the segments described above. This will require a significant commitment of time and resources, expert analysis, and will potentially require interaction and information sharing with industry and regulatory agencies outside of the reporting entity. Information typically required for this type of analysis includes:[106]

- Detailed inventories of the amount and types of process infrastructures (e.g., wells, minor field installations, and major production and processing facilities).
- Production disposition analysis (e.g., oil and gas production; vented, flared and re-injected volumes of gas; fuel gas consumption).
- Accidental releases (e.g., well blow-outs and pipeline ruptures).
- Typical design and operating practices and their impact on the overall level of emission control.

Reporters will use this information in conjunction with a variety of other data and methods in order to estimate emissions. Relevant estimation methods include emissions factor/inference-based estimates, empirical correlations, process simulations (including a variety of software applications available), and extrapolation using additional field measurements.[107]

Emissions factors and other estimation data for the natural gas and oil industries are continually updated and modified. Reporters should consult industry literature to ensure that they are using the most up-to-date methods and information possible. Important resources for reporters from

[106] Taken from *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual, Energy* (1997), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.
[107] Intergovernmental Panel on Climate Change, *Good Practice Guidance and Uncertainty Management for National Greenhouse Gas Inventories* (2000), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*.

these industries include the EPA's *Compilation of Air Pollutant Emission Factors, Version 5, AP-42* for the petroleum industry;[108] the American Petroleum Institute's standards and technical publications, statistical reports and regulatory reports;[109] EPA's *Emissions Inventory Improvement Program, Volume Eight - Greenhouse Gas Emissions*, Chapter 3, "Methods for Estimating Methane Emissions from Natural Gas and Oil Systems;"[110] and EIA's "*Documentation for Emissions of Greenhouse Gases in the United States 2003.*"[111]

Additionally, the American Petroleum Institute's *Compendium of Greenhouse Gas Emission Estimation Methodologies for the Oil and Gas Industry*[112] discusses a variety of methods and resources for estimating emissions from the following sources:

Fugitive emissions:

| | |
|---|---|
| -Flaring | $CH_4$ |
| -Storage Tank Flashing Losses | $CH_4$, $CO_2$ |
| -Transportation Loading | $CH_4$ |
| -Ballasting | $CH_4$ |
| -Losses During Transit | $CH_4$ |
| -Well Testing | $CH_4$ |
| -Exploratory Drilling | $CH_4$ |
| -Equipment Leaks | $CH_4$ |
| -Maintenance Activities | $CH_4$, $CO_2$ |
| -Turnaround Activities | $CH_4$, $CO_2$ |
| -Emergency/Upset Conditions | $CH_4$, $CO_2$ |

Emissions from vents and stacks:

| | |
|---|---|
| -Glycol Dehydrators | $CH_4$, $CO_2$ |
| -Glycol Pumps | $CH_4$ |
| -Acid Gas Removal | $CH_4$ |
| -Sour Gas Processing | $CO_2$ |
| -Catalytic Cracking Regenerators | $CH_4$, $CO_2$ |
| -Refinery Hydrogen Plants | $CO_2$ |
| -Cokers | $CO_2$ |
| -Catalyst Regeneration | $CO_2$ |
| -Cold Process Vents | $CH_4$, $CO_2$ |
| -Gas Driven Pneumatic Devices | $CH_4$, $CO_2$ |
| -Gas Driven Chemical Injection Pumps | $CH_4$, $CO_2$ |

The most accurate estimates of emissions will typically come from direct measurements. This is most plausible for emissions from point sources, including process vents and emission stacks, although fugitive emissions can also be estimated by taking direct measurements of equipment leaks and losses. Direct measurements will often be used in conjunction with empirical

[108] Available at web site www.epa.gov/ttn/chief/ap42/ch05/.
[109] Available at web site api-ep.api.org/index.cfm.
[110] Available at web site www.epa.gov/ttn/chief/eiip/techreport/volume08/index.html.
[111] Available at web site www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf.
[112] Available at web site api-ec.api.org/filelibrary/2004_COMPENDIUM.pdf.

correlation equations and other activity data to derive an emission estimate. In general, estimates based on direct, site-specific measurements will be assigned a rating of "A," provided measurement equipment is calibrated at least twice annually. Reporters should be able to document all of the methods, data and techniques used for each emission estimate.

Many emissions, particularly for the oil industry, can be estimated using a mass balance approach. The *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual* provides an overview, guidance, and methods for performing mass-balance estimates of methane emissions from oil production, crude oil transportation and refining, and from losses during oil exploration and drilling. In general, emission estimates based on a mass balance approach will be assigned a rating of "B." Again, reporters should be able to document all of the methods, data and techniques used for each emission estimate.

In the absence of other data, reporters can estimate emissions using default emissions factors based on general activity data. Those estimates tend to have very high levels of uncertainty, and should only be used as a last option. IPCC's *Good Practice Guidance* provides a table of default emissions factors for fugitive emissions from oil and gas operations based on North American data. Reporters can find default emissions factors from a variety of other published sources, including the EPA's *AP-42*, API's *Compendium of Greenhouse Gas Estimation Methodologies*, and the EPA's *Emission Inventory Improvement Program*. In general, emission estimates based on default emissions factors will be assigned a rating of "C."

Ratings of methods for estimating emissions from natural gas and oil operations are summarized in Table 1.E.29. In situations where reporters must use multiple authorities to estimate emissions from a particular source (e.g., where the method for calculating emissions from a single source is a multi-stepped process, and reporters use values or methods from more than one authority to complete the process), estimates will be assigned the rating of the lowest rated method used.

**Table 1.E.29. Rating of Estimation Methods for Carbon Dioxide and Methane Emissions from Oil and Natural Gas Industries**

| Estimation Method | Rating |
|---|---|
| Direct, site-specific measurements | A |
| Mass-balance approach, including documentation on all data, factors, and methods | B |
| Default emissions factors based on general activity data | C |

### 1.E.4.3 Waste Handling

Many industries generate considerable quantities of waste or byproduct during the course of their process activities. Waste is also generated by a number of non-industrial sources, including human wastes collected in sewage and drainage systems. Depending on their composition and how they are treated or stored, these waste streams can release significant quantities of greenhouse gas emissions, usually as a result of the aerobic and anaerobic decomposition of the organic matter in the waste. In some cases, these emissions will account for an industry's primary source of greenhouse gas emissions. Given the wide range of potential emissions arising from the variety of wastes, and treatment and storage practices, it is important for reporters to accurately characterize the nature and fate of the waste for which they are estimating emissions.

In this guidance, waste will be classified as solid or liquid. Solid waste can be collected in landfills, recycled, composted or combusted. While a large percentage of the solid waste that is generated by industries may be sold or transferred to off-site, centralized landfills, some industrial facilities may store waste in on-site landfills. Liquid wastes, referred to herein as "wastewater," are generally treated to remove undesirable or potentially harmful contents, including soluble organic matter, suspended solids, pathogenic organisms, and chemical contaminants. Once treated, wastewater may be further processed, or discharged into nearby sewage systems or bodies of water. Reporters should use this guidance to estimate only those emissions that are generated from the wastes that they handle or treat directly. This section provides specific guidance on estimating emissions from landfills and from domestic and industrial wastewater.

Carbon dioxide and methane are the primary greenhouse gases released during the biological decomposition of the organic content of waste. The relative availability of oxygen is a critical determinant of the composition of the evolved biogas. When oxygen is abundant, aerobic bacteria perform the majority of the decomposition, breaking organic matter into simple carbohydrates, and eventually into hydrogen gas, carbon dioxide and carboxylic acids. When free oxygen is not available, is in low concentrations, or has been consumed by the action of aerobic bacteria, anaerobic (or methanogenic) bacteria decompose organic material and produce methane.

While the complete mechanisms are still not understood, other factors affecting the composition and rate at which biogas is emitted include the temperature, composition (e.g., relative ratio of lipids, carbohydrates, inert substances, organic and inorganic contents), chemical characteristics (e.g., acidity, salinity, alkalinity), and physical characteristics (e.g., size, surface area, interstitial space) of the waste materials. The accuracy of emission estimates is therefore generally correlated to the degree to which the waste material is characterized. Specific guidance is provided to help reporters account for these variables associated with their wastes.

While waste management generates most greenhouse gases in some quantity, the most significant of these is methane.[113] Landfills are the single largest source of anthropogenic methane emissions in the United States, accounting for nearly 26 percent of methane emissions in 2002.[114] In some cases methane emissions are collected and subsequently flared or combusted to produce heat or to generate electricity. In both practices, the methane is converted to carbon dioxide via combustion. Methane and carbon dioxide emissions are accounted for in the following ways:

- Carbon dioxide emissions from the aerobic bacterial decomposition of wastes are considered biogenic and therefore do not count as reportable greenhouse gas emissions under the 1605(b) Program.

[113] Human waste and other high-protein wastewater streams generate nitrous oxide emissions. These emissions are discussed in the Wastewater Handling section, directly below.
[114] U.S. Energy Information Administration, *Emissions of Greenhouse Gases in the United States 2002* (November 2003), web site: www.eia.doe.gov/oiaf/1605/gg03rpt/pdf/057302.pdf or www.eia.doe.gov/oiaf/1605/gg03rpt/index.html

- Methane emissions from the anaerobic bacterial decomposition of wastes are considered anthropogenic and should be included in estimates of greenhouse gas emissions.

- Carbon dioxide emissions from flaring methane derived from wastes are considered biogenic and need not be reported since they will result in net-zero carbon dioxide emissions.

- Carbon dioxide emissions from combusting methane in landfill gas for energy purposes (e.g., heat, electricity generation) are considered biogenic and should not be included in estimates of greenhouse gas emissions. Electricity and heat generated from waste-derived methane may, under the circumstances specified by the General Guidelines, result in an emission reduction or "avoided emissions" by displacing electricity or heat generated through fossil fuel combustion, see Chapter 2, Emission Reductions.

- Treatment of emissions from the combustion of waste matter for energy is dependent on the nature of the waste matter. Carbon dioxide emissions from the combustion of organic waste matter are considered biogenic, and therefore are not to be included in estimates of greenhouse gas emissions. Carbon dioxide emissions from the combustion of inorganic, or petroleum-derived waste matter, however, are considered anthropogenic and should be estimated using the methods described in Part C, "Stationary Combustion."

In some cases, an industrial facility will operate more than one waste management or handling facility. In these instances, emissions should be calculated separately for individual facilities. Total emissions should be summed after emissions from individual facilities are estimated.

The following subsections discuss emissions from wastewater treatment and landfills, respectively.

#### 1.E.4.3.1 Methane Emissions from Domestic and Industrial Wastewater Handling

Wastewater is generated by both industrial and domestic sources. Domestic wastewater is composed primarily of human wastes, sewage and urban run-off, and is typically treated in centralized municipal treatment facilities. Many industries produce wastewater streams of varying content, which are either disposed of directly (e.g., fed into a municipal treatment facility) or treated on-site. This section provides guidance on estimating emissions from both domestic and industrial wastewater treatment practices.

Wastewater streams most likely to produce significant methane emissions are those that are rich in organic matter, including domestic wastewater as well as wastewater streams from the pulp and paper manufacturing industries, meat and poultry packing industries, and vegetable, fruit and juice processing industries. According to the U.S. EPA, domestic wastewater treatment generated 19.8 million metric tons carbon dioxide equivalent of methane emissions in 2003,

while wastewater from the pulp and paper, meat and poultry packing, and fruit and juice industries emitted 16.9 million metric tons carbon dioxide equivalent in the same year.[115] Wastewater can also be generated during the manufacture of textiles, petrochemical products, fertilizers, iron and steel, and organic chemicals.

Due to the variability of the composition of wastewater streams, emission rates are specific to source and industry. Estimates based on measured wastewater stream composition data will be assigned a rating of "A." Where direct measurement of the wastewater stream composition is not practical, reporters can use default source or industry-specific emissions factors. Estimates based on default emissions factors will be assigned a rating of "B."

The level and number of treatment operations to which wastewater is subjected are highly variable. Some industries perform minimal treatment before discharging into sewage systems or other treatment plants. Others will subject their wastewater to much more extensive treatment, collecting the resulting biomass or emissions for energy generation, resource recovery or emission reductions. There are three general levels of treatment:

- Primary treatment – suspended solids are removed, usually by filtration and/or settling.
- Secondary treatment – organic content is further reduced through the action of microbial decomposition (aerobic or anaerobic).
- Tertiary treatment – inorganic compounds and remaining pathogens are removed through a variety of processes/applications, including chemical disinfection, advanced filtration, ion exchange, and carbon adsorption systems.

The solid components removed during primary and secondary treatment are referred to as sludge. In primary treatment, sludge consists of the materials that are physically filtered out of the wastewater. The sludge produced during secondary treatment is the result of the increase in biomass of the microbial agents responsible for the decomposition of the organic matter. Sludge also generates emissions, and is also typically subject to treatment before it can be safely disposed or used in a given application.

Due to the variety of treatment methods, and the resulting multitude of treatment combinations possible, reporters should estimate emissions from each of the wastewater treatment facilities (also referred to as "handling" facilities) separately. Emissions will vary from facility to facility based on the treatment type, content of the wastewater, and a number of other factors. The principal determinant of methane production potential for a given wastewater stream, however, is its quantity of degradable organic matter, referred to as degradable organic content or DOC.

DOC is typically expressed in terms of chemical or biochemical oxygen content (COD or BOD, respectively). BOD represents the total amount of oxygen that would be consumed by aerobic bacteria in the process of decomposing all of the organic matter contained in wastewater.

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[115] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003* (April 2005) web site: yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html.

Similarly, COD is a measure of the total amount of oxygen needed to completely oxidize the organic and oxidizable inorganic matter content of a water sample under specified conditions. Both measurements are usually given in units of mass over volume (e.g., lbs COD/square foot water).

In most cases, industrial reporters should measure DOC using COD, whereas domestic treatment facilities should estimate DOC by measuring BOD.[116] There are a number of testing systems available for reporters to measure the COD of their wastewater.[117] Reporters should follow the EPA's quality control acceptance criteria for COD measurements.[118] If direct measurements are not feasible, the IPCC provides default COD values for industrial wastewater by region and by industry.

The *Revised 1996 IPCC Guidelines for National Greenhouse Gas Estimation Inventories* provides a three-step, emissions factor-based method for estimating emissions from industrial and domestic wastewater and sludge.[119] The three steps are:

1. Estimate total DOC of all the wastewater/sludge treated at each handling facility.
2. Estimate emissions factors for each wastewater/sludge treatment process.
3. Multiply emissions factors by the DOC.

While the methods for these three steps are analogous for domestic and industrial wastewater, the method for estimating DOC differs for each. In the methods outlined below, the calculations for estimating DOC in industrial and domestic wastewater streams are presented separately. As the subsequent two steps are the same for both sources, they are presented together. The methods below will yield methane emission estimates. Sewage and other streams that contain large amounts of high protein waste will also generate emissions of nitrous oxide. A method for estimating nitrous oxide emissions is provided immediately following the one below on methane emissions.

In addition to the IPCC method for estimating methane emissions from industrial wastewater treatment presented below, reporters may use the International Council of Forest and Paper Associations (ICFPA) method developed for the pulp and paper industry by the National Council for Air and Stream Improvement, Inc.[120]

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[116] In its *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003*, the EPA uses BOD to estimate methane emissions from secondary treatment of wastewater in the pulp and paper industry due to better data availability.

[117] Commercial COD test kits are available from a variety of manufacturers, including Bioscience, Inc., Hanna Instruments, Thermo Electron Corporation, and Palintest Ltd.

[118] EPA Method 410.4 -- Chemical Oxygen Demand. Data quality indicator table is available at web site www.epa.gov/region9/qa/datatables.html.

[119] This is the same method used to estimate industrial emissions in the U.S. Environmental Protection Agency's *Inventory of U.S Greenhouse Gas Emissions and Sinks: 1990-2003* (2005), web site: yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html

[120] National Council for Air and Stream Improvement, Inc., Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills, The Climate Change Working Group of the International Council of Forest and Paper Associations, Version 1.1, July 8, 2005, web site: http://www.ncasi.org/support/downloads/default.aspx.

### *Step 1. Domestic Wastewater and Sludge: Estimate Total Organic Content*

The total DOC content of a given quantity of wastewater in a given period of time (total organic content, TOC), measured in kg BOD, can be estimated by two methods. The preferable method is to directly measure the BOD content of the wastewater/sludge treated, and extrapolate to the entire volume of wastewater/sludge treated. This value must then be corrected for the portion of DOC that is removed as sludge.

**Domestic Wastewater**

$$TOC_W \text{ (kg BOD / year)} = W * DOC_W * (1 - DS)$$

**Where:**

| | | |
|---|---|---|
| $TOC_W$ | = | total organic content of domestic wastewater, measured in kg BOD / year |
| W | = | quantity of domestic wastewater treated per year, measured in cubic meters |
| $DOC_W$ | = | degradable organic component of domestic wastewater, measured in kg BOD / cubic meters |
| DS | = | quantity of degradable organic content removed from domestic wastewater as sludge, as a percentage |

In the absence of direct BOD measurements, reporters can estimate total DOC by multiplying the total population for which they are treating wastewater by an estimate of per capita DOC production:

$$TOC_W \text{ (kg BOD / year)} = P * DCP * (1 - DS)$$

**Where:**

| | | |
|---|---|---|
| $TOC_W$ | = | total organic content of domestic wastewater, measured in kg BOD / year |
| P | = | total population served by a single treatment facility, in thousands |
| DCP | = | degradable organic component production per thousand persons per year, measured in kg BOD |
| DS | = | percentage of degradable organic content removed from domestic wastewater as sludge |

If region-specific DOC production data are not available, reporters can use the national average value of 23.7 thousand metric tons BOD produced per person per year.[121]

[121] U.S. Environmental Protection Agency, *Inventory of U.S Greenhouse Gas Emissions and Sinks: 1990-2001* (2003), web site: yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html

### Domestic Sludge

$$TOC_S \text{ (kg BOD / year)} = W * DOC_W * DS$$

**Where:**

| | | |
|---|---|---|
| $TOC_S$ | = | total organic content of domestic sludge, measured in kg BOD / year |
| W | = | quantity of domestic wastewater treated per year, measured in cubic meters |
| $DOC_W$ | = | degradable organic component of domestic wastewater, measured in kg BOD / cubic meter |
| DS | = | quantity of degradable organic content removed from domestic wastewater as sludge, as a percentage |

In the absence of direct BOD measurements, reporters can estimate total DOC by multiplying the total population for which they are treating wastewater by an estimate of per capita DOC production:

$$TOC_S \text{ (kg COD / year)} = P * DCP * DS$$

**Where:**

| | | |
|---|---|---|
| $TOC_S$ | = | total organic content of domestic sludge, measured in BOD / year |
| P | = | total population served by a single treatment facility, in thousands |
| DCP | = | degradable organic component production per thousand persons per year, measured in kg COD |
| DS | = | quantity of degradable organic content removed from domestic wastewater as sludge, as a percentage |

### *Step 2. Industrial Wastewater and Sludge: Estimate Total Organic Content*

The total quantity of organic matter in industrial wastewater and sludge can be estimated by multiplying total quantity of wastewater treated and the DOC of the wastewater and sludge.

Total organic content can be estimated using the following formulas:

### Industrial Wastewater

$$TOC_i \text{ (kg COD / year)} = W_i * O_i * DOC_i * (1 - DS_i)$$

**Where:**

| | | |
|---|---|---|
| $TOC_i$ | = | total organic content of industrial wastewater type *i*, |

**measured in kg COD / year**

| | | |
|---|---|---|
| $W_i$ | = | **quantity of wastewater type *i* produced per metric ton of industrial product, measured in cubic meters** |
| $O_i$ | = | **annual output of industrial product, in tons** |
| $DOC_i$ | = | **degradable organic component of wastewater type *i*, measured in kg COD / cubic meter** |
| $DS_i$ | = | **quantity of degradable organic content removed from wastewater type *i* as sludge, as a percentage** |

### Industrial Sludge

$$TOC_j \text{ (kg COD / year)} = WS_j * O * DOC_j * DS_j$$

**Where:**

| | | |
|---|---|---|
| $TOC_j$ | = | **total organic content of industrial sludge type *j*, measured in kg COD / year** |
| $WS_j$ | = | **quantity of sludge type *j* produced per metric ton of industrial product, measured in cubic meters** |
| $O$ | = | **annual output of industrial product** |
| $DOC_j$ | = | **degradable organic component of wastewater type *j*, measured in kg COD / cubic meter** |
| $DS_j$ | = | **quantity of degradable organic content removed from wastewater as sludge, as a percentage** |

Where direct measurements are not feasible, reporters can use the default COD values provided in Table 1.E.30.

### Table 1.E.30. Default COD Values for Various Types of Industrial Wastewater

| Industry Type | Wastewater Produced ($m^3$ / metric ton product) | COD Value (kg COD / $m^3$ wastewater) |
|---|---|---|
| Coffee | - | 8.5 |
| Potatoes | - | 3.0 |
| Vegetable Oil | 1.6 | 0.3 |
| Dairy Products | 2.8 | - |
| Cannery | 2.6 | - |
| Potato Starch | - | 8.0 |
| Wheat Starch | - | 22 |
| Petroleum Products | - | 0.4 |
| Textile mills | - | 1.0 |
| Leather tanning | - | 5.8 |
| Pulp and Paper * | 85 | 0.4 ** |
| Meat and Poultry* | 13 | 4.1 |
| Fruits, Vegetables, Juices * | 5.6 | 5.0 |

Source: Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual* (1997).
[*] U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001* (2003).
[**] BOD value

### *Step 3. Domestic and Industrial Wastewater and Sludge: Calculate Emissions Factors*

Emissions factors for different wastewater and sludge types can be calculated given the maximum methane-producing capacity and the methane conversion factor (MCF) for each type of wastewater or sludge handled, in conjunction with knowledge of the treatment type to which each wastewater or sludge stream is subjected. Methane-producing capacity depends on the composition and degradability of the wastewater or sludge. In the absence of a measured value, a default value of 0.25 kg methane/kg COD[122] can be used. Similarly, the MCF varies from zero in completely aerobic systems to one in completely anaerobic systems.

Where sludge is incinerated, burned for energy, or landfilled, its emissions should be estimated separately, using the appropriate methods (found in Part C, "Stationary Combustion" and below in subsection 1.E.4.3.3, Landfill Methane, respectively). In these cases, the sludge should be assigned an MCF of zero in order to avoid double counting. Otherwise, an MCF value representative of the system used to dispose of the sludge should be used.

Methane emissions factors for individual wastewater and sludge handling facilities can be calculated using the following formulas:

**Wastewater**

$$EF_i \text{ (kg } CH_4 \text{ / kg DOC)} = B_i * MCF_x$$

**Where:**

| | | |
|---|---|---|
| $EF_i$ | = | **methane emissions factor for wastewater type *i*, measured in kg $CH_4$ / kg DOC** |
| $B_i$ | = | **maximum methane producing capacity of wastewater type *i*, measured in kg $CH_4$ / kg DOC** |
| $MCF_x$ | = | **methane conversion factor of wastewater treatment system *x*** |

**Sludge**

$$EF_i \text{ (kg } CH_4 \text{ / kg DOC)} = B_i * MCF_y$$

**Where:**

| | | |
|---|---|---|
| $EF_j$ | = | **methane emissions factor for sludge type *j*, measured in kg $CH_4$ / kg DOC** |

[122] Equal to the maximum potential methane produced per unit COD. Value taken from Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual-Chapter 6.* (1997), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

| | | |
|---|---|---|
| **$B_j$** | **=** | **maximum methane producing capacity of sludge type *j*, measured in kg $CH_4$ / kg DOC** |
| **$MCF_y$** | **=** | **methane conversion factor of sludge treatment method *y*** |

In the absence of site-specific data, reporters can use default methane conversion factor values of zero for aerobic systems and one for anaerobic systems, respectively, and default maximum methane producing capacity values of 0.25 kg $CH_4$/kg COD and 0.6 kg $CH_4$/kg BOD for estimates of DOC measured in COD or BOD, respectively.[123]

### *Step 4. Domestic and Industrial Wastewater and Sludge: Estimate Total Methane Emissions for Individual Facilities*

In estimating total methane emissions from individual wastewater or sludge-handling facilities, methane emissions are equal to the associated emissions factor multiplied by the quantity of wastewater or sludge produced:

**Wastewater**

$$MW_i \text{ (kg } CH_4) = TOC_i * EF_i$$

**Where:**

| | | |
|---|---|---|
| **$MW_j$** | **=** | **methane emissions from wastewater type *i*, measured in kg methane** |
| **$TOC_j$** | **=** | **total organic content of wastewater type *i*, measured in kg COD or BOD / year** |
| **$EF_i$** | **=** | **methane emissions factor for wastewater type *i*, measured in kg $CH_4$ / kg TOC** |

**Sludge**

$$MS_i \text{ (kg } CH_4) = TOC_j * EF_j$$

**Where:**

| | | |
|---|---|---|
| **$MW_j$** | **=** | **methane emissions from sludge type *j*, measured in kg methane** |
| **$TOC_j$** | **=** | **total organic content of sludge type *j*, measured in kg COD / year** |
| **$EF_j$** | **=** | **methane emissions factor for sludge type *j*, measured in kg $CH_4$ / kg TOC** |

### *Step 4: Total Emissions*

[123] Intergovernmental Panel on Climate Change, *Good Practice Guidance and Uncertainty Management for National Greenhouse Gas Inventories-Chapter 5* (2000), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*.

Sum the emissions from all wastewater and sludge-handling facilities for total methane emissions from wastewater production.

Ratings of methods for estimating emissions from wastewater handling are summarized in Table 1.E.31.

**Table 1.E.31. Rating of Estimation Methods for Methane Emissions from Wastewater and Sludge Handling**

| Estimation Method | Rating |
|---|---|
| Emissions factors derived from measured wastewater stream composition data[124] | A |
| Default emissions factors and general activity data[125] | B |

### 1.E.4.3.2 Nitrous Oxide Emissions from Domestic Wastewater

Domestic wastewater streams will also generate nitrous oxide emissions. Nitrous oxide is released as a byproduct of two processes: nitrification and denitrification. Nitrification is an aerobic process through which nitrogen, present in human wastes in the form of urea, ammonia and protein, is converted ultimately to nitrate. Denitrification, in contrast, is an anaerobic process through which nitrate is biologically converted to gaseous nitrogen. Most nitrous oxide emissions occur during either wastewater treatment practices themselves, or following such treatment, when the remaining effluent is discharged into nearby aquatic environments.

Reporters can estimate nitrous oxide emissions from discharged effluent with the following equation:[126]

$$N_2O_{effluent} = Frac_{effluent} * P * Protein * Frac_{protein} * EF$$

**Where:**

| | | |
|---|---|---|
| $N_2O_{effluent}$ | = | **nitrous oxide emissions from effluent disposed of in aquatic environments** |
| $Frac_{effluent}$ | = | **fraction of wastewater that is disposed of in waterways as effluent, as a percentage** |
| **P** | = | **total population served by treatment facility** |
| **Protein** | = | **annual per capita protein intake, measured in kg / person / year** |
| $Frac_{protein}$ | = | **fraction of nitrogen in protein** |
| **EF** | = | **nitrous oxide emissions factor, as measured in kg $N_2O$-N / kg sewage-N produced.** |

[124] The ICFPA method using a ratio of COD to BOD to estimate an emissions factor (EF) is rated A.
[125] The ICFPA method using a default emissions factor (EF) is rated B.
[126] Adapted from Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual* (1997), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

Estimates based on direct measurements of emissions will be assigned a rating of "A." Estimates based on this equation in conjunction with measured, site-specific data will be rated "B." In the absence of site-specific data, reporters can use the IPCC default values provided in Table 1.E.32. Estimates based on these data will be rated "C."

### Table 1.E.32. Default Values for Estimating Nitrous Oxide Emissions from Disposed Effluent

| | |
|---|---|
| Annual per capita protein intake | 41.6 * |
| Fraction of nitrogen in protein | 0.16 kg N / kg protein |
| Nitrous oxide emissions factor | 0.01 kg $N_2O$ /kg sewage N produced |

Source: Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual* (1997).
* U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001* (2003).

Ratings of methods for estimating emissions from wastewater handling are summarized in Table 1.E.33.

### Table 1.E.33. Rating of Estimation Methods for Nitrous Oxide Emissions from Disposed Effluent

| Estimation Method | Rating |
|---|---|
| Direct measurement | A |
| IPCC method using measured, site-specific effluent data | B |
| IPCC method using default values | C |

#### 1.E.4.3.3 Landfill Methane

Methane is released from landfills through the anaerobic decomposition of organic wastes such as paper, food, and yard waste, and accounts for 30 to 60 percent by volume of all gases emitted from landfills.[127] The balance of gases includes primarily carbon dioxide and other minor constituents such as nitrogen, volatile organic compounds, and water vapor. The capture and combustion of landfill gas is a common practice used to mitigate methane and other air pollutants in the gas.[128]

The amount and rate at which methane is generated and emitted from a landfill is a function of several factors, including but not limited to, the composition of waste, PH levels in the landfill, moisture content of the waste, the landfill temperature, and the amount of oxidation that occurs as the methane passes through the landfill cover material. Additionally, methane is not emitted immediately after it is placed in a landfill. The time lag before anaerobic decomposition of organic matter begins and the pace of that decomposition are dependent on the above factors.

Reporters may choose from two basic methodological approaches for estimating methane emissions from landfills. The first, the First Order Decay (FOD) model, captures the temporal

[127] The other major gas is carbon dioxide, which is considered biogenic (part of the natural carbon cycle) and therefore does not need to be included in the emission estimates from this source.
[128] For a discussion of the treatment of emissions from the combustion of recovered methane, refer to the general discussion of waste, above.

profile of decomposition, while the latter, the EMCON Methane Generation Model, simply captures a snapshot of total methane emissions from any given volume of waste landfilled.

The First Order Decay model captures the temporal profile of decomposition and requires multiple-year data on:

- The amount of waste landfilled;
- The degradable organic portion of the waste;
- The fraction of the degradable organic portion that actually decomposes;
- The fraction of methane in landfill gas;
- The methane generation rate constant (representing the half-life of the degradable organic portion of the waste);
- The portion of methane generated that is oxidized in cover soil; and
- The amount of methane recovered from the landfill.

The FOD model can be represented by the equation:

$$CH_4 \text{ Generated in year } t = \Sigma_x \left[(A * k * MSW_{t(x)} * MSW_{f(x)} * L_{0(x)}) * e^{-k(t-x)}\right]$$

**For x = initial year to t**

**Where:**

| | | |
|---|---|---|
| **t** | **=** | **year of inventory** |
| **x** | **=** | **years for which input data should be added** |
| **A** | **=** | **$(1- e^{-k})/k$; normalization factor which corrects the summation** |
| **k** | **=** | **methane generation rate constant (1/number of years)** |
| **$MSW_{t(x)}$** | **=** | **total municipal solid waste generated in year x** |
| **$MSW_{f(x)}$** | **=** | **fraction of municipal solid waste disposed at landfills in year x** |
| **$L_{0(x)}$** | **=** | **methane generation potential [$MCF_{(x)}$ * $DOC_{(x)}$ * $DOC_{(f)}$ * F * 16/12** |
| **e** | **=** | **Euler's constant equal to the natural logarithm base *e*, approximately 2.71828** |
| **$MCF_{(x)}$** | **=** | **methane correction factor for year x (fraction)** |
| **$DOC_{(x)}$** | **=** | **degradable organic carbon in year x (fraction)** |
| **$DOC_{(f)}$** | **=** | **Fraction of DOC dissimilated** |
| **F** | **=** | **Fraction by volume of $CH_4$ in landfill gas** |
| **16/12** | **=** | **Conversion of carbon to $CH_4$** |

The degradable organic carbon content of the waste can be calculated by determining the composition of waste, using data which include:

- The fraction of waste that is paper and textiles;
- The fraction that is yard waste;
- The fraction that is food waste; and
- The fraction that is wood or straw.

For the detailed requirements of this method, reporters should refer to the waste sections in both the *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual*[129] and the *IPCC Good Practices Guidance and Uncertainty Management in National Greenhouse Gas Inventories*.[130] In order to use this model, detailed knowledge of the waste characteristics and landfill parameters listed above is required. If those data are available and used, this method is assigned a rating of "A."

There are a number of publicly available tools for implementing the First Order Decay model based on a combination of critical default factors and key landfill-specific parameters. They include LandGEM, available at no cost from the U.S. Environmental Protection Agency and downloadable from the Internet at www.epa.gov/ttn/catc/products.html#software. The LandGEM model uses a first-order decomposition rate equation to estimate annual gas generation over any time period specified by the user. The following list of information is required for the LandGEM model to estimate gas generation from a landfill:

- The design capacity of the landfill;
- The amount of refuse landfilled each year (waste acceptance rate);
- The opening and closing years of the landfill;
- The methane generation rate (k) (default values are available);
- The methane generation potential ($L_o$) (default values are available); and
- The concentration of methane, (default values are available).

As noted above, the LandGEM model can be run using either user-defined data or program-provided default values for k, $L_o$ and methane concentration. If site-specific data are not available, LandGEM's "AP-42" default values may be used.

If site-specific data are used for all inputs required by LandGEM, emissions estimates are assigned a rating of "A." If default values are used, emissions estimates using LandGEM are assigned a rating of "B."

Alternatively, reporters may wish to use the default parameters from the EMCON Methane Generation Model in conjunction with estimates of volume of waste landfilled each year as a simplified method of capturing the temporal profile of waste decomposition in their landfill.[131] This model provides default factors for waste composition, methane yield, time lag to onset of

[129] Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual* (1997), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm .
[130] Intergovernmental Panel on Climate Change, *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (2000), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*
[131] Energy Information Administration, *Documentation for Emissions of Greenhouse Gases in the United States 2003*(Washington, DC May 2005), web site: www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf.

waste decomposition, and a time constant reflecting the total time required for the methane yield to be realized.

The EIA has developed a parameterization of the EMCON model that is used to develop estimates of national methane emissions. This method may be applied to individual landfills by inserting the parameters listed in Table 1.E.34 and volumes of waste landfilled on an annual basis into EIA's spreadsheet application. Reporters should take an average of the high-yield and low-yield scenario for each of the three different waste categories—readily decomposable, moderately decomposable, and slowly decomposable waste—and sum these emissions on an annual basis.

If site-specific data are used for all inputs required by EMCON, emissions estimates are assigned a rating of "A." If default values are used, emissions estimates using EMCON are assigned a rating of "B.

### Table 1.E.34. EMCON Methane Generation Model Parameters for Calculating Methane Emissions

| Waste Category | Decomposable Portion (% by Dry Weight) | Methane Yield (Cubic Feet per Pound) | Lag Time (Years) | Time Constant (Years) |
|---|---|---|---|---|
| **High Yield** | | | | |
| Readily Decomposable | 4 | 4.5 | 0.2 | 3 |
| Moderately Decomposable | 45 | 3.6 | 1.5 | 10 |
| Slowly Decomposable | 5.2 | 0.5 | 5 | 20 |
| **Low Yield** | | | | |
| Readily Decomposable | 4 | 2.8 | 0.3 | 4 |
| Moderately Decomposable | 45 | 2 | 2 | 20 |
| Slowly Decomposable | 5.2 | 0.3 | 5 | 40 |

Source**:** Energy Information Administration, *Documentation for Emissions of Greenhouse Gases in the United States 2003* (Washington, DC May 2005), www.eia.doe.gov/oiaf/1605/ggrpt/documentation/pdf/0638(2003).pdf.

When the First Order Decay Model or its derivatives are used, an oxidation rate of 10 percent should be used to reflect the oxidation of some of the methane produced while it passes through the landfill cover material. When using the EMCON parameters, simply reduce the total estimate of emissions for any given year by 10 percent to reflect oxidation. If the landfill has a recovery system in place, the amount recovered should be deducted from total estimated emissions before the emissions are reduced by 10 percent to account for oxidation.[132] This is represented by the equation:

$$CH_4 \text{ emissions} = (CH_4 \text{ generated in year t} - CH_4 \text{ Recovery in year t}) * (1 - \text{oxidation rate})$$

[132] U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003. (April,* 2005), web site: yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html.
.

The First Order Decay Model and its derivative tools require a time-series of data on amounts of waste landfilled for multiple years prior to the inventory reporting year. If data on landfilled waste are only available for a single year or a limited number of years, the theoretical gas yield methodology may also be used. This mass balance approach assumes that all the potential methane in a given amount of waste is released from the landfill in the same year the waste is landfilled. This method does not precisely portray what happens in a landfill over time, but provides a reasonable estimate of the total amount of methane released over time from a given amount of waste. Reporters should use caution when using the mass balance approach if the waste stream is changing or there is methane recovery. This approach is found under the *Revised 1996 IPCC Guidelines* and is given a rating of "C." To estimate a single year's methane emissions from landfilled waste use the following formula:

$$CH_4 \text{ Emissions} = [(\text{Waste landfilled} * \text{DOC} * \text{Dissimilated DOC} * 0.5 * 16/12) (CH_4 \text{ recovered})] * (1 - \text{oxidation rate})$$

**Where:**

| | | |
|---|---|---|
| **DOC** | **=** | **Fraction of Degradable Organic Carbon Content in waste (Gg C/Gg waste).** |
| **Dissimilated DOC** | **=** | **Fraction of DOC dissimilated (Gg C/Gg waste)** |
| **$CH_4$ recovered** | **=** | **Methane captured or otherwise prevented from being emitted** |
| **16/12** | **=** | **Molecular weight ration of methane to carbon** |
| **Oxidation rate** | **=** | **Rate of oxidation (%)** |
| **Waste landfilled** | **=** | **Waste landfilled (Gg)** |

However, if data on the degradable organic content, the fraction of DOC dissimilated, or the oxidation factor are unavailable, then reporters may use the following IPCC default values:[133]

$$CH_4 \text{ Emissions} = [\text{Waste landfilled} * 0.21(\text{DOC}) * 0.77(\text{Dissimilated DOC}) * 0.5 * 16/12] - (CH_4 \text{ recovered}) * (1 - \text{oxidation rate})$$

An oxidation rate of 10 percent may be assumed.

Emissions estimates using the mass-balance method based on the default values will be assigned a rating of "D."

Ratings of methods for estimating emissions from landfills are summarized in Table 1.E.35.

[133] Intergovernmental Panel on Climate Change, *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (1997), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

### Table 1.E.35. Rating of Estimation Methods for Methane Emissions from Landfilling

| Estimation Method | Rating |
|---|---|
| IPCC First Order Decay model using site-specific waste and landfill parameters | A |
| Publicly available models, including LandGem and EMCON, that rely on user-defined data elements | A |
| Publicly available models, including LandGem and EMCON, that rely on default parameters | B |
| Mass balance using single (or limited number of) year(s), site-specific DOC data | C |
| Mass balance, default DOC values | D |

### 1.E.4.4 High Global Warming Potential Gases

Many industries emit a host of gases known as high global warming potential (GWP) gases. Although typically emitted in relatively small quantities, these gases are of concern because some of these gases have over 10,000 times the global warming potential[134] of carbon dioxide on a pound-per-pound basis.

The use and release of these gases varies widely by industry and by process. High GWP gases can be used as cover gases (as in magnesium production), as substitutes for ozone-depleting propellants (as in aerosols), or as cleaning agents (as in semiconductor manufacture). The industrial uses of high GWP gases discussed in this guidance are indicated in Table 1.E.36.

### Table 1.E.36. Industrial Processes Associated with Emissions of High GWP Gases

| Industry | Gases Emitted |
|---|---|
| Aluminum production | PFCs, $SF_6$ |
| HCFC-22 manufacture | HFC-23 |
| High-tension electrical equipment | $SF_6$ |
| Industrial Use of Hydrocarbons, Perfluorocarbons, and Sulfur Hexafluoride as Substitutes for Ozone-Depleting Substances, including use and assembly of refrigeration and air conditioning equipment, open and closed cell foam blowing, leakage from fire extinguishers, use of solvents, and other miscellaneous uses | HFCs, PFCs, $SF_6$ |
| Magnesium production | $SF_6$ |
| Semiconductor manufacture | HFCs, PFCs, $SF_6$ |

This guidance does not attempt to provide detailed coverage of estimation methods for the diversity of end-uses for high GWP gases. In many cases, reporters are referred to other documented emissions estimation authorities and resources. In those instances, ratings are provided for the referenced estimation methods.

[134] As described in the glossary, global warming potential is an index used to compare the relative radiative forcing of different gases without directly calculating the changes in atmospheric concentrations. GWPs are calculated as the ratio of the radiative forcing that would result from the emission of one kilogram of a greenhouse gas to that from the emission of one kilogram of carbon dioxide over a fixed period of time, such as 100 years.

#### 1.E.4.4.1 Aluminum Production

A number of high GWP gases are emitted during different stages of aluminum production and processing. Two PFCs, tetrafluoromethane ($CF_3$) and hexafluoroethane ($C_2F_6$), are emitted during the smelting process. Sulfur hexafluoride ($SF_6$) is used as a cover gas and emitted in some aluminum foundries. For a discussion of how to estimate these emissions, please refer to subsection 1.E.4.1.3, "Aluminum Production," above.

#### 1.E.4.4.2 HCFC-22 Production

Trifluoromethane (HFC-23) is a high GWP greenhouse gas that is generated as a byproduct during the manufacture of chlorodifluoromethane (HCFC-22). Unlike the majority of HFC emissions, most HFC-23 emissions are point-source emissions, emitted through the condenser vents of HCFC-22 manufacturing plants. Reporters can estimate HFC-23 emissions through either direct measurement or inference. Some HCFC-22 manufacturers may capture some of the HFC-23 byproduct and sell it for use in various applications from which it is eventually emitted. Captured HFC-23 should not be included in the inventory of the entity (though all process, fugitive and other emissions associated with its manufacture should always be included).

Continuous emission monitoring (CEM) of all of a plant's exhaust streams[135] can accurately measure HFC-23 emissions. Emission estimates based on CEM data will be assigned a rating of "A," provided they meet the quality assurance criteria discussed under subsection 1.E.3.1, "Direct Measurement," above.

If continuous monitoring is not available, emissions can be estimated from periodic measurements of the exhaust streams. Reporters can estimate emissions with periodic measurements by multiplying the concentration of HFC-23 in the exhaust stream by the volumetric flow-rate of the exhaust stream and by the time elapsed during the reporting period. Emission estimates based on representative direct measurement will be assigned a rating of "A," provided they meet the quality assurance criteria discussed under subsection 1.E.3.1,"Direct Measurement," above.

If direct measurement systems are not available, reporters can estimate HFC-23 emissions using a production-based, emissions factor approach. In the absence of plant-specific data, reporters can assume that HFC-23 emissions are equal to 4 percent of the quantity (by mass) of HCFC-22 produced.[136] Some plants might employ HFC-23 abatement or capture technologies. If reporters have an estimate for the rate of HFC-23 abatement, they should use it; if not, it should be assumed equal to zero. HFC-23 emissions can be calculated using the following equation:

**HFC-23 emissions (tons) = 0.04 * HCFC-22 produced (tons) * (1 – abatement factor (percent))**

[135] Usually the condenser vent.
[136] Default value from Intergovernmental Panel on Climate Change, *Greenhouse Gas Inventory Reference Manual: Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* (1997), web site: www.ipcc-nggip.iges.or.jp/public/gl/invs1.htm.

Emissions estimates based on production data and a default factor developed through public or private consensus processes refereed by an organization such as the IPCC, U.S. EPA, or API are rated "B." Emission estimates based on production data and an industry-wide default factor will be assigned a rating of "C."

Ratings of methods for estimating emissions from HCFC-22 production are summarized in Table 1.E.37.

### Table 1.E.37. Rating of Estimation Methods for HFC Emissions from HCFC-22 Production

| Estimation Method | Rating |
|---|---|
| Continuous emissions monitoring | A |
| Emission estimates based on representative, periodic direct measurement | A |
| Default, uncontrolled emissions factor, abatement/capture technology reduction value if applicable, from consensus-based published sources | B |
| Default, industry-wide uncontrolled emissions factor, abatement/capture technology reduction value if applicable | C |

#### 1.E.4.4.3. $SF_6$ Emissions from Electrical Equipment

Sulfur hexafluoride has various uses and emissions associated with electrical equipment. The IPCC provides instructions for estimating emissions from these sources. Reporters should consult IPCC Good Practice Guidance[137] for details about the various estimation methods, which include mass balance by life cycle state of equipment (IPCC Tier 3a), mass balance at the manufacturer and facility level (IPCC Tier 3b), the inference method by life cycle stage using emissions factors (IPCC Tier 2a), the inference method using IPCC default emissions factors (IPCC Tier 2b), and the potential emissions method (IPCC Tier 1). Table 1.E.38 lists these IPCC methods and their ratings.

### Table 1.E.38. Rating of Estimation Methods for Sulfur Hexafluoride Emissions from Electrical Equipment

| Estimation Method | Rating |
|---|---|
| Mass balance by life cycle stage of equipment (IPCC Tier 3a) | A |
| Mass balance at the manufacturer and facility level (IPCC Tier 3b) | A |
| Inference method by life cycle stage using emissions factors (IPCC Tier 2a) | B |
| Inference method using IPCC default emissions factors (IPCC Tier 2b) | C |
| Potential emissions method (IPCC Tier 1) | D |

#### 1.E.4.4.4 Industrial Use and Production of Hydrofluorocarbons, Perfluorocarbons and Sulfur Hexafluoride

Many industries have historically used ozone-depleting substances in their products. Following the passage of the Montreal Protocol and the 1990 Amendments to the Clean Air Act, however, the production and use of these substances in the United States has widely been phased out and replaced with a host of non-ozone-depleting substitutes, including hydrofluorocarbons (HFCs)

[137] Intergovernmental Panel on Climate Change, *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (2000), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*.

and perfluorocarbons (PFCs). Although they do not contribute to ozone depletion, the release of these chemicals is of concern due to their very high global warming potentials and long atmospheric lifetimes.

In addition to uses as substitutes for ozone depleting substances, HFCs, PFCs, and $SF_6$ are used in a wide variety of industrial processes.[138] Industrial uses of HFCs and PFCs include the manufacture and use of refrigeration and air conditioning, fire suppression and explosion protection, aerosol manufacture and use, solvent cleaning, foam blowing, equipment sterilization, and the manufacture of coatings, adhesives and inks. $SF_6$ is commonly used to insulate switchgear and circuit breakers (for explosion protection) in semiconductor manufacture and aluminum and magnesium foundries. With the exception of PFC emissions from aluminum and HFC-23 emissions from HCFC-22 manufacture, emissions of HFCs, PFCs, and $SF_6$ are largely fugitive emissions associated with the prior purchase of manufactured chemicals by these industries.

Where direct measurement of emission streams is impractical, estimates can be derived from records of purchase or usage of those manufactured chemicals. It is possible to visualize several potential situations:

- *Consumptive use data are available*. For some sectors, including magnesium production and aerosol use, consumption data can be used to estimate emissions. Reporters should refer to the methodological guidance provided by IPCC's *Good Practice Guidance* noted above and the EPA's "Climate Leaders Protocol"[139] and follow instructions on accounting for changes in equipment and chemical stock, which implicitly accounts for chemical recycling.

- *Maintenance or repair data are available*. This might occur with HFCs used as a refrigerant or sulfur hexafluoride used in electrical systems. In these instances, emissions may be calculated either by estimating the volume of gas lost as a result of each failure, or measuring the volume of gas added to replace assumed losses. Reporters should be aware, however, of the potential for recycling and for emissions from equipment that is being decommissioned or taken out of service, and take care to prevent double counting or not counting the associated emissions.

- *Gas purchase data are available*. Industrial gases are presumably purchased for consumptive use, but reporters using purchase data need to be aware of the importance of tracking new equipment, the potential for chemical stock change (i.e., the reporter maintains a supply of gas, and the inventory changes will affect consumption), the potential for recycling, and unreplaced losses from decommissioned equipment.

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[138] For a detailed discussion of the various source categories of HFC, PFC, and $SF_6$ emissions, refer to the U.S. Environmental Protection Agency's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2003* (April 15, 2005), web site: yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2005.html.

[139] U.S. Environmental Protection Agency, Office of Atmospheric Programs, Climate Protection Partnerships Division, Climate Leaders Program, web site: www.epa.gov/climateleaders/.

In general, emissions estimates based on mass balance using consumptive use data, when reinforced by taking into account losses from changes in chemical stock, equipment scrappage, or recycling (if available), will be the most accurate. Where consumptive use data are not available, estimates based on gas purchase data can be reinforced by estimates of stock change and losses from equipment scrappage and possible gains from recycling. In most cases, very broad emission estimates can be made using estimates of equipment stock data, though these estimates will have a large margin of error.

This guidance does not attempt to provide reporters with complete coverage of the methods needed to estimate emissions. Reporters are urged instead to consult the sources listed in the tables for each end use discussed below.

#### 1.E.4.4.4.1 Use of Refrigeration and Air Conditioning

Many companies use refrigerating and/or air conditioning or cooling facilities within the scope of their organizational boundaries. Typical uses include domestic, mobile, and commercial unitary air conditioning units, chillers, cold storage, retail food storage, refrigerated transport, and heat pumps.[140] Table 1.E.39 includes a list of sources that currently provide methods for estimating emissions arising from the use of these systems.

**Table 1.E.39. Sources and Ratings for Estimating Emissions from Use of Air Conditioning and Refrigeration Equipment**

| **EPA Climate Leaders** *www.epa.gov/climateleaders/core.html* | **Rating** |
|---|---|
| Material Balance Method | A |
| Simplified Material Balance Method | A |
| **IPCC Good Practice Guidance** *http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm* | |
| Mass Balance, or Top-Down Approach that does not rely on emissions factors | A |
| **IPCC Revised 1996 Guidelines** *www.ipcc-nggip.iges.or.jp/public/gl/invs6.html* | |
| Tier 2 - Actual Emissions, using facility-specific emissions factors that have been demonstrated to be highly representative | A |
| Tier 2 - Actual Emissions, using reasonably representative facility-specific emissions factors | B |
| Tier 2 - Actual Emissions, using country-specific emissions factors | C |
| Tier 1 - Potential Emissions | D |
| **California Climate Change Action Registry-General Reporting Protocol** *www.climateregistry.org/protocols/grp* | |
| Mass Balance Method | A |

Note: Equally rated methods may be fundamentally the same method reported by different authorities.

The *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories* provides a "potential" (Tier 1) and an "actual" (Tier 2) method for estimating emissions of high-GWP gas emissions from the following industries and activities:

- Open and closed cell foam blowing
- Manufacture and assembly of refrigerating devices

[140] U.S. Environmental Protection Agency, "Climate Leaders Greenhouse Gas Inventory Protocol, Core Module Guidance -- Direct HFC and PFC Emissions from Use of Refrigeration and Air Conditioning Units" (October 2004), Web site: www.epa.gov/climateleaders/docs/refrige_acequipuseguidance.pdf.

- Leakage from fire extinguishers
- Use as solvents
- Use of $SF_6$ in high tension electrical equipment, circuit breakers and gas insulated switchgear
- Miscellaneous use

Reporters should consult the IPCC guidelines for details about the estimation methods. As indicated in Table 1.E.39, above, estimations based on the mass balance method will be assigned a rating of "A," while estimations based on other methodologies reported in the IPCC Revised 1996 Guidelines may be assigned a rating of A, B, C, or D, depending on the assumed accuracy with which the reporter's emissions factors represent actual rates (e.g., site-specific emissions factors are assumed to be more representative than country-specific factors).

### 1.E.4.4.5 Magnesium Production

Sulfur hexafluoride ($SF_6$) is used as a cover gas to prevent the oxidation of molten magnesium during smelting, casting and other production processes. It is generally accepted that none of the sulfur hexafluoride is reacted with or consumed while used, but rather that it is all emitted directly into the atmosphere after use.[141] The amount of sulfur hexafluoride emitted during magnesium production is thus equal to the amount consumed:

$$SF_6 \text{ Emissions} = SF_6 \text{ Consumption}$$

For most reporters, consumption data can be easily inferred from purchase data. If consumption or purchase data are not available, reporters can estimate emissions using production data and a default emissions factor. Table 1.E.40 provides emissions factors for six major processes that use sulfur hexafluoride:

**Table 1.E.40. $SF_6$ Emissions Factors from Magnesium Production Processes**

| Process | Emissions Factor (kg $SF_6$ / metric ton Mg) |
|---|---|
| Secondary Production | 1.0 |
| Die Casting | 0.74 |
| Die Casting (small parts) | 5.2 |
| Gravity Casting | 2 |
| Wrought Products | 1 |
| Anodes | 1 |

Source: U. S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2000* (2003).

Emission estimates based on consumption data will be assigned a rating of "A." Estimates based on default emissions factors in Table 1.E.40 will be assigned a rating of "B."

Ratings of methods for estimating emissions from magnesium production are summarized in Table 1.E.41.

[141] Intergovernmental Panel on Climate Change, *IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* (2000), web site: *www.ipcc-nggip.iges.or.jp/public/gp/english/*.

**Table 1.E.41. Rating of Estimation Methods for $SF_6$ Emissions from Magnesium Production**

| Estimation Method | Rating |
|---|---|
| Mass balance using consumption data | A |
| Default emissions factors based on general activity data | B |

### 1.E.4.4.6 Semiconductor Manufacture

The semiconductor manufacturing industry emits a variety of high global warming potential gases, including fluorocarbons ($CF_4$, $C_2F_6$, $C_3F_8$, c-$C_4F_8$, and $CHF_3$), and sulfur hexafluoride ($SF_6$). The relative quantity of each gas emitted (referred to collectively as fluorinated compounds, FCs) is site-specific, and depends on the processes employed, the machinery, and the specifications of the manufacturing process. In general, though, FCs are emitted from two distinct processes: plasma etching and chemical vapor deposition (CVD).

Direct monitoring of emissions from silicon manufacturing, through CEM or periodic measurements, is rare because of its high cost and technical difficulty. The *IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories* outlines four general approaches for estimating FC emissions from silicon manufacturing, three of which are applicable to plant-level estimations.[142] The methods are differentiated by the level of production data they require, as follows:

- *Tier 2a - Process-specific parameters:* company- or plant-specific data are available for the amount of gas used in each process or by each tool (or subset thereof), the amount of purchased but unused gas remaining in the shipping container, the amount of gas destroyed or transformed during the manufacturing process, the amount of gas transformed to $CF_4$ during the manufacturing process, the amount of gas used by processes equipped with emission control technologies, and the fraction of gas destroyed by those technologies. Estimates based on these data will be assigned a rating of "A."

- *Tier 2b - Process type-specific parameters:* company- or plant-specific data are available for the amount of gas used in each *type* of process or tool. Generic industry-wide values can be used for the amount of purchased but unused gas remaining in the shipping container, the amount of gas destroyed or transformed for each process type, the amount of gas transformed to $CF_4$ for each process type, and the fraction of gas destroyed by emission control technologies. Plant-specific data should be used when available. Estimates based on these data will be assigned a rating of "B."

- *Tier 2c - FC-specific parameters:* company- or plant-specific data are available for gas sales/purchases and for emission control technologies. Default values specified for Tier 2b can be used, though plant-specific data are preferable where available. Estimates based on these data are rated "C."

Reporters should consult the IPCC guidelines for the details of each method.

[142].Intergovernmental Panel on Climate Change. *IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*. (2000), web site: www.ipcc-nggip.iges.or.jp/public/gp/english/.

Alternatively, the World Resources Institute/World Business Council for Sustainable Development provides an automated worksheet that estimates emissions based on characteristics of the semiconductors produced, production data, and a choice of plant-specific or industry default values.[143] Estimates made using this worksheet will be assigned a rating of "C," unless the company- or plant-specific data required for the "B" rating are used, in which case the worksheet method is rated "B."

Ratings of methods for estimating emissions from semiconductor manufacturing are summarized in Table 1.E.42.

**Table 1.E.42. Rating of Estimation Methods for High GWP Gas Emissions from Semiconductor Manufacturing**

| Estimation Method | Rating |
|---|---|
| Mass Balance at the specific process or tool level (IPCC Tier 2a) | A |
| Mass Balance at the process- or tool-type level (IPCC Tier 2b) | B |
| Mass Balance using WRI spreadsheets with plant-specific data | B |
| Mass Balance using site-specific purchase and abatement data (IPCC Tier 2c) | C |
| Mass Balance using WRI spreadsheets with default factors | C |

### 1.E.4.5 Special Situations: Geologic Sequestration

In some cases, industrial reporters may capture some of the carbon dioxide emitted from their industrial processes and use this carbon dioxide for geologic sequestration, either through enhanced oil recovery or injection into a permanent storage reservoir, such as a deep coal seem or a saline aquifer. The specific capture technologies and storage reservoirs for geologic sequestration are described further in Part G along with the steps for tracking and reporting emissions from the sequestration process.

In some situations, the industrial entity may undertake both the capture and storage activity itself, but in other cases the entity may choose to sell or transfer the captured carbon dioxide to another entity for final sequestration. In either case, the reporter would need to track the origin of all potential carbon dioxide emissions, including the fraction that is being captured. However, it is the reporter's responsibility to include it its inventory only those emissions of carbon dioxide that occur from facilities it owns or controls.

If a fraction of carbon dioxide is captured and permanently sequestered by the entity that created the carbon dioxide, then that fraction shall be treated as a "negative emissions." These negative emissions offset an equivalent amount of the entity's emissions from creating the carbon dioxide. Part G describes accepted accounting methodologies for sequestering carbon dioxide through enhanced resource recovery and injection into a permanent storage reservoir. If an entity reports any negative emissions from sequestering carbon, the entity must report on all carbon dioxide sources and sinks that fall within the entity boundary, including any fugitive emissions from handling the captured gas. If the reporter uses additional energy in the form of fossil fuel

[143] This worksheet is available at web site www.ghgprotocol.org/templates/GHG5/layout.asp?type=p&MenuId=OTAx&doOpen=1&ClickMenu=No.

combustion or electricity to capture, separate, or compress the carbon dioxide, direct or indirect emissions from this energy use should be reported following guidance in Part C, “Stationary Combustion,” and Part D, “Indirect Emissions.”

Some carbon dioxide is usually leaked after the point of capture due to the additional steps involved with treating and compressing it to a consistency amenable for transport. The entity in possession of the gas at the time of emission is responsible for including such emissions in its inventory. Most likely, the transfer would take place at the point of input or output of a carbon dioxide pipeline, and the amount of carbon dioxide sold would be recorded through flow meters set up to measure the amount of gas supplied to or extracted from the pipeline.

# Part F: Indirect Emissions

Outline

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# Technical Guidelines Chapter 1, Part F: Indirect Emissions

## 1.F.1 Overview

The General Guidelines provide that reporters must report indirect emissions arising from the consumption of electricity, steam, and hot and chilled water separately from direct emissions in their Emissions Inventories. This section describes methods and standards for estimating those emissions. Indirect emissions associated with other activities can also be reported, but not included in Emission Inventories.

Most reporters will generate indirect emissions somewhere within their organizational boundaries. For many reporters, most reportable emissions will be indirect. Indirect emissions are emissions from outside the organizational boundary of an entity that are the result of an entity's energy use or other activities. These emissions are normally emitted by another entity. The most commonly reported forms of indirect emissions are caused by the consumption of electricity, steam, and hot and chilled water. In general, estimation and reporting of indirect emissions presents three challenges:

- When indirect emissions are reported, the potential exists for reporting of the same emissions by more than one party.
- The actions of the party that “owns” or controls the emission source directly may strongly influence the level of emissions.
- The reporter may find it difficult or impossible to obtain information about an emission source that it does not own or control.

In most cases, energy products such as heat and electricity are generated through the combustion of fossil fuels. In these cases, indirect emissions are generated through stationary combustion. Although these emissions are not generated directly by the reporting entity, all reporters should know the concepts behind estimating emissions from stationary combustion and some reporters will need to apply this knowledge in the preparation of their reports. Throughout this section reporters are asked to refer to Part C of this Chapter, “Stationary Combustion.” Reporters who are unfamiliar with the fundamentals of stationary combustion or with estimating emissions from combustion processes are strongly encouraged to read Part C.

The only facilities that will not report indirect emissions are those that generate all of their thermal and electrical needs on-site,[144] or those that meet all of their energy demands by using renewable or other biogenic or non-emitting sources.[145]

[144] Those facilities should consult Part C, “Stationary Combustion.”
[145] For the purposes of the voluntary reporting program, renewables such as wind and solar are considered zero emissions sources. In keeping with the general approach of emissions reporting under the 1605(b) Program, upstream (fuel-cycle) emissions related to production, maintenance, and related activities are attributed to the producer of the renewable energy.

## 1.F.2 Indirect Emissions from the Purchase of Electricity, Heat and Cooling: Concepts

Indirect emissions are those that result from the consumption of energy at a given site that is provided by a remote source or supplier. Indirect emissions are driven by facilities' consumption of "useful" energy commodities (referred to herein as "energy products"), such as heat and electricity. Energy products are typically generated by harnessing the energy stored in a "less useful" form (e.g., fossil fuels) and converting it to a more useful one (e.g., electricity). The conversion is the process where emissions are generated.

Once an energy product has been generated, it is transmitted and distributed[146] to the site where it will be consumed. The three major sources of indirect emissions are electricity purchases, heating/steam purchases, and consumption of cooling products, such as chilled water.

In general, there are three factors to consider when estimating indirect emissions: the quantity of energy product consumed, the emissions from the generation of that product, and how much energy is lost to the environment while transmitting the product to the site where it is consumed. These components are related by the following equation:

$$\textbf{Indirect Emissions}_{\text{Reporting Entity}} = \textbf{Emission Factor}_{\text{Energy Supplier}}\ \textbf{(quantity emissions /unit of energy)} * \textbf{Energy consumption}_{\text{Reporting Entity}}\ \textbf{(units of energy)} * \textbf{Transmission Loss Adjustment Factor (\%)}$$

The typical arrangement when considering indirect emissions is that of a consumer purchasing an energy product that is generated remotely and sold by a dedicated supplier. There are, however, several other scenarios that warrant special considerations, and these are discussed below under "Energy Purchases and Sales."

### 1.F.2.1 Emissions

Carbon dioxide ($CO_2$), methane ($CH_4$), and nitrous oxide ($N_2O$) are the principal greenhouse gases that are accounted for when estimating indirect emissions. While carbon dioxide emissions should always be reported, the standards for reporting nitrous oxide and methane emissions depend on the source of the indirect emissions. While some generating technologies produce no or virtually no nitrous oxide or methane emissions, other technologies may produce them in significant quantities.

### 1.F.2.2 Electricity

Electricity generation accounts for approximately one-third of the greenhouse gases emitted in the United States each year.[147] Carbon dioxide accounts for the vast majority (over 99.5 percent)

[146] Transmission usually refers to the longer distance, higher capacity (e.g., higher voltage, greater steam throughput) travel. Distribution refers to lower capacity conveyance that allocates products to individual users. Throughout the remainder of this section, the term "transmission" will be used to refer collectively to the transmission and distribution of energy products.

of GHG emissions from grid-generated electricity. Because methane and nitrous oxide normally account for a combined total of less than 0.5 percent of GHG emissions, reporters may decide to include them in the *de minimis* emissions excluded from their reports.

Given that grid-supplied electricity originates from a changing mix of generators embedded in an extensive, interconnected network through which specific electricity flows are virtually impossible to document, it is inaccurate to base emissions from grid-supplied electricity on those of a single plant, utility, or even state. In most instances, electricity will be purchased from a regulated utility[148] or other load-serving entity that operates within the context of a power control region. In a specific power control region, electricity is provided by a host of generators that are brought online by a regional authority (usually a Regional Transmission Operator or an Independent System Operator) according to changes in demand, transmission restrictions, plant generating characteristics, environmental factors, and their own, established dispatch order. In order to minimize the burden on reporters and avoid possible gaming, most reporters must use regional emission factors to be specified by the Energy Information Administration (EIA). Only those reporters that purchase electricity directly from specific generators will need to obtain information about how the electricity they consume is generated (see discussion below).

Average regional emission rates by state-defined regions for grid-supplied electricity will be provided by EIA and will be updated periodically. Unless reporters know that their electricity is purchased and delivered from a particular plant (see discussion below), reporters should presume that power purchased from electricity utilities is "grid-generated" power and can be reasonably represented with regional emission factors. Under these conditions, the reporter should employ the appropriate regional emission factor.

After heat or electricity is generated, it must travel some distance to the load where it will be 'consumed'. During transmission, some portion of it will be irreversibly lost. Resistance in electricity lines converts some quantity of electricity into heat, which is dissipated into the environment. Consequently, generators must produce a quantity of energy that exceeds the final demand of the end user. An adjustment factor for transmission losses will be incorporated into the emissions factors provided by EIA. Therefore, reporters may accurately estimate total indirect emissions by simply multiplying their energy consumption data by the appropriate emissions factors.

In rare cases, customers purchase electricity that is generated by and delivered from a specific generating plant. Direct sales might be arranged through public utilities, independent suppliers via public utilities, or directly with non-utility generators (NUGs). Directly purchased electricity can originate from a variety of sources, including diesel generators, cogeneration (i.e., combined heat and power [CHP]) plants,[149] and renewable generators.

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[147] U.S. Energy Information Administration, *Emissions of Greenhouse Gas Emissions in the United States 2002* (2003), web site: www.eia.doe.gov/oiaf/1605/ggrpt/index.html.

[148] While the generation of electricity has been opened to market competition in many states, all public utilities are still regulated at some level, usually at the level of electricity transmission and distribution.

[149] It is not uncommon for facilities that operate cogeneration (i.e., CHP) plants to sell their electricity if they cannot use it on site. Facilities that purchase electricity from cogeneration plants should refer to the discussion on Electricity or Heat Supplied by a Combined Heat and Power Generator, below, in order to address the considerations particular to cogeneration.

Due to the disparity in emissions from these various sources, reporters whose facilities acquire electricity from a specific source should try to obtain source-specific emissions information (i.e., emissions factors, total purchased electricity from source and source adjustment factor for system-specific transmission losses) from their electricity supplier. Contrary to grid-supplied electricity, their supplier may emit significant quantities of methane and nitrous oxide. If the supplier does not record its emissions data, reporters should determine what generation technology and fuel sources are employed to produce the supplier's electricity. Reporters should then estimate the plant's emissions factors using the methods outlined in Part C. In cases where methane and nitrous oxide emissions are not included in the *de minimis* emissions excluded from the entity's report, reporters should estimate and record those emissions using the same method employed for estimating methane and nitrous oxide emissions described in Part C.

Some reporters may be engaged in a green power-purchasing contract. Only those reporters that have plant-specific contracts with renewable energy providers may report such purchases. Reporters that buy power from the grid must use the state-based emission factors specified by EIA and treat the green power purchases as offset reductions (see Chapter 2, Emission Reductions).

### 1.F.2.3 Steam / Hot Water

Supplied steam or heat is usually generated from direct, documentable sources of energy. If the source of the supplied heat is known, reporters should account for the carbon dioxide, nitrous oxide, and methane emissions. If a supplier can provide emission rates and an adjustment factor for transmission losses, they should be used in concert with purchased energy to calculate indirect emissions from purchased heating. Otherwise, reporters should obtain information about the fuel type and heat generation technology used by their supplier and estimate emissions using the stationary combustion methods outlined in Part C.

Like electricity, during the transmission of steam or hot water, some portion of the heat energy will be irreversibly lost. While heat is transported, some quantity of heat energy will be absorbed by the environment due to imperfect insulation. Most heat generators will keep records of transmission losses, which are highly variable and depend largely on the network through which they are transported. Reporters should try to obtain transmission loss data from their suppliers. Reporters should incorporate the transmission loss adjustment factor, which is defined by the following equation, into their indirect emissions estimate:

$$\text{Transmission loss adjustment factor} = 1 / (1 - \text{transmission loss } (\%))$$

For example, if the transmission loss is 10 percent, the transmission loss factor will be equal to

$$1/(1-.1) = 1/0.9 = 1.11$$

### 1.F.2.4 Chilled Water

Some facilities will purchase "cooling" for either cooling or refrigeration when they do not operate cooling compressors on-site. Cooling comes in the form of a chilled substance—usually water. Conceptually, purchased chilled water is similar to purchased heat or steam, with the primary difference being the process employed to generate the chilled water. As with purchased heat, the following discussion applies only to facilities that are supplied with cooling by an external party.

Chilled water is typically generated by pressurizing a gaseous substance with a compressor and then allowing the substance to return to standard pressure. When the pressure is released from the gas, it absorbs thermal energy as it expands, lowering the temperature of the immediate environment—or in this case, whatever product that is going to serve as the "vehicle" for the cooling product. Generally, compressors are powered by either an electrical motor or by a combustion engine.

During transmission from the supplier to the end-user, chilled water will absorb energy from the environment, which will result in an increase in the temperature of the chilled water. Consequently, generators must chill water to a temperature below the temperature required for the end-user to make up for these inevitable losses. Most suppliers will keep records of transmission losses, which vary widely based on the specific transmission system. Reporters must account for the transmission losses using the transmission loss adjustment factor, represented by the following equation:

**Transmission loss adjustment factor = 1 / (1- transmission loss (%))**

For example, if the transmission loss is 10 percent, the transmission loss factor will be equal to

**1/(1-.1) = 1/0.9 = 1.11**

The ratio of cooling demand to energy input for a cooling plant is known as the plant's "coefficient of performance" (COP). To estimate emissions, reporters need to know either the plant-specific COP, which is preferable, or which type of compressor their cooling supplier uses. If the supplier's COP value is not available, default values are provided based on the type of compressor. If the supplier uses a combustion engine-driven compressor, reporters can calculate the compressor's emissions using the stationary combustion methods outlined in Part C. If the compressor is powered by an electric motor, reporters should follow the steps for estimating indirect emissions from electricity consumption discussed in this section. In addition to plant-specific emissions or equipment data, reporters should try to obtain transmission loss data from their suppliers. Reporters should incorporate the transmission loss adjustment factor, defined above, into their indirect emissions estimate.

### 1.F.2.5 Energy Consumption

Knowing the amount of energy consumed is essential to estimating indirect emissions. Fortunately, this amount is easily quantifiable because electricity, steam, and heated or chilled

water are usually provided at a metered rate that reflects the energy content of the product sold. Purchase records should provide adequate information about the quantity of energy consumed. If an organization has a number of buildings or devices that consume independently monitored electricity, these must all be accounted for.

Unfortunately, some facilities do not independently monitor their energy consumption. This is often true in the case of leased office space, where utility bills can be bundled into the rental fee. In those instances, energy use is usually monitored at the level of the entire building.

If entity-level energy consumption data are not available, the following "area" method can be used to estimate energy consumption[150] (if reporters do not have access to this information, a building manager may be able to provide it):

$$\textbf{Energy Use}_{\text{Facility}} = (\textbf{Area}_{\text{Facility}} / \textbf{Area}_{\text{Building}}) * \textbf{Energy Consumption}_{\text{Building}}$$

Where:

| | | |
|---|---|---|
| **Energy Use** $_{\text{Facility}}$ | = | **The amount of energy consumed in an office space, leased property or other facility that is housed within a larger building** |
| **Area** $_{\text{Facility}}$ | = | **The area of the facility for which energy consumption is being estimated** |
| **Area** $_{\text{Building}}$ | = | **The total area of the building in which the facility is housed** |
| **Energy Consumption** $_{\text{Building}}$ | = | **Aggregated energy consumption data for the entire building** |

Heat, electricity, and cooling are usually sold in different units. Electricity is most commonly sold and metered by the kilowatt-hour (kWh). Typical units for measuring and selling heat include British thermal units (Btu, often expressed in units of millions [MMBtu]), therms (equal to 100,000 Btu), and pounds of steam. Cooling is usually sold in ton-hours. Reporters may encounter instances where it is useful to express these terms in common units. Use the conversion factors provided in Table 1.F.1 when it is necessary to convert between units.

**Table 1.F.1. Common Conversion Factors for Power Consumption**

| | |
|---|---|
| 1 kWh = | 3412.13 Btu |
| 1 Therm = | 100,000 Btu |
| 1 Gigajoule (Gj) = | 0.95 MMBtu* |
| 1 ton/hour cooling = | 12,000 Btu |
| *1 MMBtu equals 1 million Btu | |

It is common for steam to be measured in pounds of steam. In these cases, reporters must calculate the quantity of heat extracted from the steam, measured in MMBtu. This calculation requires measuring the difference between the heat content (enthalpy) of the steam when

[150] Method adopted from: World Business Council for Sustainable Development / World Resources Institute, *Working 9 to 5 on Climate Change: An Office Guide* (December 2002), web site: www.safeclimate.org.

purchased and when at a reference temperature.[151] In this case, the reference temperature is that of saturated water at 212 degrees Fahrenheit (enthalpy = 180 Btu/lb).[152]

In some cases, suppliers will be able to provide the heat content of their delivered steam; otherwise, reporters must estimate it themselves. Estimating the heat content of the purchased steam requires monitoring the steam's temperature and pressure. Enthalpy values for steam at different temperatures and pressures are available in steam tables. A condensed steam table is provided in Table 1.F.2, below.[153]

### Table 1.F.2. Condensed Table of Enthalpy Values for Steam and Saturated Water

| Gauge Pressure (psig) | Steam Temp (°F) | Enthalpy of Sat. liquid (Btu/lb) | Enthalpy of Steam (Btu/lb) |
|---|---|---|---|
| 0 | 212.00 | 180.07 | 1150.4 |
| 1.3 | 216.32 | 184.42 | 1152.0 |
| 2.3 | 219.44 | 187.56 | 1153.1 |
| 5.3 | 227.96 | 196.16 | 1156.3 |
| 10.3 | 240.07 | 208.42 | 1160.6 |
| 15.3 | 250.33 | 218.82 | 1164.1 |
| 20.3 | 259.28 | 227.91 | 1167.1 |
| 25.3 | 267.25 | 236.03 | 1169.7 |
| 30.3 | 274.44 | 243.36 | 1172.0 |
| 40.3 | 287.07 | 256.30 | 1175.9 |
| 50.3 | 297.97 | 267.50 | 1179.1 |
| 60.3 | 307.60 | 277.43 | 1181.9 |
| 70.3 | 316.25 | 286.39 | 1184.2 |
| 80.3 | 324.12 | 294.56 | 1186.2 |
| 90.3 | 331.36 | 302.10 | 1188.1 |
| 100.0 | 337.90 | 308.80 | 1188.8 |
| 110.3 | 344.33 | 315.68 | 1191.1 |
| 120.3 | 350.21 | 321.85 | 1192.4 |
| 125.3 | 353.02 | 324.82 | 1193.0 |
| 130.3 | 355.76 | 327.70 | 1193.5 |
| 140.3 | 360.50 | 333.24 | 1194.6 |
| 150.3 | 365.99 | 338.53 | 1195.6 |
| 160.3 | 370.75 | 343.57 | 1196.5 |
| 180.3 | 379.67 | 353.10 | 1198.0 |
| 200.3 | 387.89 | 361.91 | 1199.3 |
| 225.3 | 397.37 | 372.12 | 1200.6 |
| 250.3 | 406.11 | 381.60 | 1201.7 |

Source: Center for Energy Efficiency and Renewable Energy, *Process / Equipment Heat Recovery*, web site: www.ceere.org/iac/assessment%20tool/ARC2243.html.

[151] This method for estimating energy consumption from purchased steam is derived from the California Climate Action Registry, *General Reporting Protocol* (October 2002), web site: www.climateregistry.org/PROTOCOLS/GRCP/.

[152] American Petroleum Institute, *Compendium of Greenhouse Gas Estimation Methodologies for the Oil and Gas Industry* (2001), web site: http://api-ec.api.org/policy/index.cfm?bitmask=001001004002000000.

[153] Alternatively, reporters can refer to steam tables available on-line, including at the following web sites: www.engineeringtoolbox.com/28_457.html or www.efunda.com/materials/water/steamtable_sat.cfm.

The heat content of the purchased steam can now be calculated using the following equation:

$$\text{Energy Content}_{\text{Purchased Steam}}\ (\text{MMBtu}) = [\text{Enthalpy}_{\text{Purchased Steam}}\ (\text{Btu/lb}) - 180\ (\text{Btu/lb})] * [\text{Steam Consumed (lbs)}] * [1\text{MMbtu} / 1{,}000{,}000\ \text{Btu}]$$

### 1.F.2.6 Power Purchases / Acquisitions and Sales / Transfers

The majority of reporters reading this section will be reporting for facilities that only import power, although some may also export power. Power imports include power purchased or otherwise acquired from a direct supplier or utility. Power exports can include power that is generated on-site and provided to another user, or power that is purchased from a separate supplier and subsequently resold to another end user (e.g., retail power purchases). In general, reporters should not report any indirect emissions associated with purchased power that is subsequently re-sold or otherwise exported.

## 1.F.3 Methods for Estimating Indirect Emissions

### 1.F.3.1 Electricity Imports (not from cogeneration)[154]

**1) Estimate Total Electricity Consumption**

Reporters should begin by calculating the total quantity of electricity purchased for use by their entity. Care should be taken to include all relevant facilities and independently metered electricity consuming devices. If electricity consumption is metered and recorded by the organization, those data should be used. Otherwise, purchase records or utility/supplier bills will provide an accurate measure of electricity consumption. These data are usually measured in kWh. If direct consumption records are not available, estimate consumption using the "area" method outlined above, under "Energy Consumption."

**2) Determine an Appropriate Emission Factor**

Once electricity consumption has been estimated, reporters must find an emission factor for their electricity source. For the vast majority of electricity users, electric power is supplied from a grid, and reporters should use an emission factor that represents the average emissions from state-based region where the supplier is located. These emission factors will be provided by EIA. The emission factors provided will have been adjusted to account for transmission losses.

[154] This method is adapted from the following sources:
- U.S. Environmental Protection Agency, *Climate Leaders Greenhouse Gas Inventory Protocol,* "Indirect Emissions from Purchases / Sales of Electricity and Steam" (Draft, June 2003), web site: http://www.epa.gov/climateleaders/resources/cross_sector.html.
- World Business Council for Sustainable Development / World Resources Institute, *Greenhouse Gas Protocol Initiative* (2001), web site: http://www.ghgprotocol.org/plugins/GHGDOC/details.asp?type=DocDet&ObjectId=MTM3NTc.
- California Climate Action Registry, *General Reporting Protocol* (October 2002), web site: www.climateregistry.org/PROTOCOLS/GRCP/.

For the few reporters whose electricity is supplied directly from a known source, emissions data specific to that source should be used. Purchases from "known sources" refer to power that is supplied from a dedicated plant or source that can be specifically identified. "Known sources" do not include specific utilities, suppliers or known power regions; generator-specific information is required. Entities might purchase power from dedicated sources under specific contracts arranged through utilities or independent power suppliers, or under contracts arranged directly with generators (for purchases from CHP plants, refer to the discussion on Electricity or Heat Supplied by a Combined Heat and Power Generator, below). If available, reporters should use specific annual emissions data for known sources. If only the type of the generating plant is known, default emission rates in Table 1.F.3 can be used. If accounting for nitrous oxide and methane emissions, and emission factors are available, reporters should use them.

**Table 1.F.3. Carbon Dioxide Emission Rates for Various Generator Types**

| Carbon Coefficients of Common Fuels * | | | | |
|---|---|---|---|---|
| **Fuel** | **Coal** | **Natural Gas** | **Residual Oil** | **Distillate Oil** |
| Emission Factor (kg $CO_2$ / MMBtu) | 93.5 | 52.8 | 78 | 72.4 |

| **Emission Factors of a Variety of Generator Types** | | | |
|---|---|---|---|
| | **Heat Rate - HHV ** (MMBtu / kWh)** | **Fuel Type** | **Emission Factor (kg $CO_2$ / kWh)** |
| Advanced Combustion Turbine | 0.0094 | Natural Gas | 0.50 |
| | | Residual Oil | 0.73 |
| | | Distillate Oil | 0.68 |
| Advanced Gas / Oil Combined Cycle | 0.0070 | Natural Gas | 0.37 |
| | | Residual Oil | 0.55 |
| | | Distillate Oil | 0.51 |
| Conventional Combustion Turbine | 0.0109 | Natural Gas | 0.58 |
| | | Residual Oil | 0.85 |
| | | Distillate Oil | 0.79 |
| Conventional Gas / Oil Combined Cycle | 0.0075 | Natural Gas | 0.40 |
| | | Residual Oil | 0.59 |
| | | Distillate Oil | 0.54 |
| Distributed Generation - Baseload | 0.0094 | Natural Gas | 0.50 |
| | | Residual Oil | 0.73 |
| | | Distillate Oil | 0.68 |
| Distributed Generation - Peak | 0.0104 | Natural Gas | 0.55 |
| | | Residual Oil | 0.81 |
| | | Distillate Oil | 0.75 |
| Fuel Cells | 0.0075 | Natural Gas | 0.40 |
| Integrated Coal-Gasification Combined Cycle | 0.0080 | Coal | 0.75 |
| Scrubbed Coal – New | 0.0090 | Coal | 0.84 |

**Source:** * U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2003,* Table 2 (2003), web site: www.eia.doe.gov/oiaf/aeo/assumption/index.html.
** U.S. Energy Information Administration, *Assumptions to the Annual Energy Outlook 2003,* Table 40 (2003), web site: www.eia.doe.gov/oiaf/aeo/assumption/index.html.

### 3) Estimate Indirect Emissions

Reporters who are among the majority of electricity users whose electric power is supplied from a grid should use the following formula to estimate emissions:

$$\textbf{Indirect Emissions}_{\textbf{Reporting Entity}} = \textbf{Consumption}_{\text{Reporting Entity}} * \textbf{Emissions Factor}_{\textbf{Supplier}}$$

Reporters with electricity supplied directly from a known source should use the following formula to estimate emissions:

$$\textbf{Indirect Emissions}_{\textbf{Reporting Entity}} = \textbf{Consumption}_{\text{Reporting Entity}} * \textbf{Transmission loss adjustment factor} * \textbf{Emission Factor}_{\textbf{Supplier}}$$

Ratings of emissions estimates will be assigned based on the data used, as described in Table 1.F.6.

**Table 1.F.4. Rating of Estimation Methods for Indirect Emissions from Electricity Imports**

| Estimation Method / Data Used | Rating |
|---|---|
| Measured electricity consumption in conjunction with source-specific, generator-type or default regional or default national emission rates and system-specific or default transmission loss factor* | A |
| "Area" method estimate of electricity consumption in conjunction with source-specific, generator-type or default regional or default national emission rates and system-specific or default transmission loss factor* | B |

* Transmission loss factor applies only to reporters whose electricity is supplied directly from a known source. Regional emissions factors presented in this section have already been adjusted for transmission losses.

## 1.F.3.2 Steam or Hot Water Imports (not from cogeneration)[155]

Steam and hot water are used to provide office heating in the commercial sector and process heating in the industrial sector. As with all indirect emissions, it is important to remember that the discussion included here applies *only* to facilities that purchase or otherwise acquire heat energy from an external supplier. Facilities that operate boilers, generators or other devices to supply their own thermal energy should refer to Part C for stationary combustion methods to

[155] This method is adapted from the following sources:
-U.S. Environmental Protection Agency, *Climate Leaders Greenhouse Gas Inventory Protocol*, "Indirect Emissions from Purchases / Sales of Electricity and Steam" (Draft, June 2003), web site: http://www.epa.gov/climateleaders/resources/cross_sector.html.
-World Business Council for Sustainable Development / World Resources Institute, *Greenhouse Gas Protocol Initiative* (2001) , web site: http://www.ghgprotocol.org/plugins/GHGDOC/details.asp?type=DocDet&ObjectId=MTM3NTc.
-California Climate Action Registry, *General Reporting Protocol* (October 2002), web site: www.climateregistry.org/PROTOCOLS/GRCP/.

estimate those direct emissions. Facilities that this discussion applies to typically include leased office spaces that purchase heating from building managers, and commercial or industrial facilities that purchase heating from a district heating system.

**1) Estimate Purchased Heat/Steam**

Reporters should begin by calculating the quantity of steam/hot water purchased. If steam imports are metered and recorded by the organization, those data should be used. Otherwise, purchase records or utility/supplier bills will provide an accurate measure of delivered steam/heat, which may be recorded in terms of energy, mass or volume. If the only available emission factors require data in a metric that is different from the metric in which the data are reported, use the conversion factors listed in Table 1.F.1 to make the necessary conversion. If direct consumption records are not available, estimate consumption using the "area" method outlined above, under "Energy Consumption."

**2) Obtain an Appropriate Emission Factor**

If possible, an emission factor (tons $CO_2$ / MMBtu heat generated) should be obtained directly from the supplier. If the supplier cannot provide one, reporters can use a default emissions value of 78.95 kg $CO_2$/MMBtu.[156]In cases where methane and nitrous oxide emissions are not included in the *de minimis* emissions excluded from the entity's report, reporters should use default emissions factors from Part C if source-specific emissions factors are not available.

**3) Estimate Emissions**

Using the emission factor obtained above, indirect emissions from purchased hot water and steam can be calculated with information on the quantity of energy consumed,[157] and transmission losses. These factors are related by the following formula:

$$\textbf{Indirect Emissions} = \textbf{Energy Consumption} * \textbf{Emission factor}_{\textbf{Supplier}} * \textbf{Transmission loss adjustment factor}$$

If reporters cannot obtain an estimate of transmission losses from their supplier, they can use a default loss rate of 10 percent.

Ratings of emissions estimates will be assigned based on the data used, as described in Table 1.F.5.

[156] Weighted average based on EIA's 1998 Manufacturers Energy Consumption Survey data on the quantities of natural gas, coal, and residual and distillate fuel oils consumed as boiler fuel, carbon coefficients provided in EIA's Assumptions to the Annual Energy Outlook 2003, and OIAF efficiency assumptions of 80, 81, and 82 percent for natural gas, coal and petroleum boilers, respectively.

[157] For guidance on estimating the energy content of purchased steam or hot water, see the discussion under Section 1.F.2.5- Energy Consumption, above.

**Table 1.F.5. Rating of Estimation Methods for Indirect Emissions from Steam or Hot Water Imports**

| Estimation Method / Data Used | Rating |
|---|---|
| Measured heat consumption in conjunction with source-specific emission factor and source-specific or default transmission loss factor | A |
| Measured heat consumption in conjunction with default emission factor and source-specific or default transmission loss factor | B |
| "Area" method estimate of heat consumption in conjunction with source-specific emission factor and source-specific or default transmission loss factor | C |
| "Area" method estimate of heat consumption in conjunction with default emission factor and source-specific or default transmission loss factor | D |

### 1.F.3.3 Chilled Water Purchases[158]

Reporters can estimate emissions associated with purchased chilled water by using values for the COP of the supplying plant. If reporters cannot obtain plant-specific COP values, default values are provided.

**1) Estimate Cooling Demand**

Refer to monthly cooling bills to estimate the yearly cooling demand of the relevant facility. If the supplied cooling is reported in ton-hours of cooling, convert it to million Btus (MMBtu) at the rate of 12,000 Btu per ton-hour as illustrated in Table 1.F.1.

**2) Estimate Supplier's COP**

If it is possible to obtain specific information about a cooling plant's COP, use this information. If not, a cooling supplier should be able to tell reporters the type of chiller they use in their cooling plant. Default COP values for different chiller types are provided in Table 1.F.6.

**Table 1.F.6. Default Coefficient of Performance Values for Various Chiller Types**

| Chiller Type | Coefficient of Performance | Energy Source |
|---|---|---|
| Absorption Chiller | 0.8 | Natural Gas |
| Engine-Driven Chiller | 1.2 | Natural Gas |
| Electric-Driven Chiller | 4.2 | Electricity |

**Source:** California Climate Action Registry, *General Reporting Protocol* (October 2002).

[158]This method is adapted from: California Climate Action Registry, *General Reporting Protocol* (October 2002), web site: www.climateregistry.org/PROTOCOLS/GRCP/.

**3) Calculate Cooling Plant Inputs from Energy Demand**

The amount of energy input into the cooling system to meet an entity's demand can be estimated by dividing entity-cooling demand by the COP of the cooling plant (note that energy input for natural gas systems is denominated in thermal energy and energy input for electrical systems is denominated in electrical energy). The cooling plant energy input is represented by the following equation:

$$\text{Energy Input}_{\text{Cooling plant}} = (\text{Cooling Demand}_{\text{Reporting Entity}} * \text{Transmission loss adjustment factor}) / (\text{COP}_{\text{Cooling plant}})$$

Reporters should try to obtain an estimate of transmission losses from their supplier. If their supplier cannot provide one, they can use a default loss rate of 10 percent.[159]

**4) Calculate Emissions**

If an engine-driven compressor drives the cooling plant, emissions from its fuel consumption can be estimated using the energy input value calculated above and the methods for estimating emissions from stationary combustion detailed in Part C, "Stationary Combustion."

If an electricity-driven compressor drives the cooling plant, emissions from its electricity use can be estimated using the energy input value calculated above and the methods for estimating indirect emissions from electricity use detailed above.

Ratings of emissions estimates will be assigned based on the data used, as described in Table 1.F.7.

### Table 1.F.7. Rating of Estimation Methods for Indirect Emissions from Chilled Water Purchases

| Estimation Method / Data Used | Rating |
|---|---|
| Measured chilled water consumption data used in conjunction with source-specific COP and a source-specific or default transmission loss factor | Same rating as given to the method used to calculate emissions (see Step 4) |
| Measured chilled water consumption data used in conjunction with default COP and source-specific or default transmission loss factor | One value rating lower than the rating given to the method used to calculate emissions (see Step 4) |
| "Area" method estimates of chilled water consumption used in conjunction with source-specific COP and source-specific or default transmission loss factor | Two value ratings lower than the rating given to the method used to calculate emissions (see Step 4) |
| "Area" method estimates of chilled water consumption in conjunction with default COP and source-specific or default transmission loss factor | D |

[159] For guidance on estimating a transmission loss adjustment factor, see the discussion under the section on Chilled Water, above.

### 1.F.3.4 Electricity or Heat Supplied by a Combined Heat and Power Generator

Unlike the majority of electricity users, most purchasers of thermal energy know the specific generator, and their energy purchases are covered by a contract with that source. Only those users that have a CHP plant-specific contract for heat or power should use this method.

Unlike the topics discussed above, CHP is not a specific energy product. The term refers to a power generating arrangement that simultaneously generates electricity and useful heat. In the process of producing electricity, combustion generators give off significant quantities of heat. In most generating processes, this heat is lost to the environment. In contrast, CHP systems capture and redirect this heat so that it can be applied in a usable manner. The benefit of capturing and using this "waste" heat is an increase in fuel use efficiency.

Combined heat and power is used in applications where there is a concurrent demand for thermal and electrical energy.[160] The benefit of meeting these demands with a CHP generator is that the fuel use efficiency of most CHP systems is greater than what would be achieved by meeting electrical and thermal demands by separate processes. Whereas many facilities consume both the thermal and electrical energy produced by CHP systems on-site, others may find it profitable to sell ("export") either thermal and/or electrical energy if they generate either of these in surplus. If purchasing power from an independent supplier, reporters should ascertain whether or not it is generated by a CHP system.

Entities that use all of the thermal and electrical output of a CHP plant that they own and operate should use the methods outlined in Part C, "Stationary Combustion," to estimate emissions. If an entity consumes all of the heat *and* electricity output from an external supplier's CHP plant, estimating emissions is straightforward: indirect emissions will be equal to the total emissions of the CHP plant. When purchasing a portion of plant output of either electricity or heat alone, the procedure is somewhat more involved than it is for dedicated generating sources, and is outlined below.

Because CHP plants simultaneously produce electricity and usable heat from a single fuel source and generating process, care must be taken not to "double count" emissions by allocating total emissions to both products. Instead, reporters must account for emissions in a way that reflects the relative "share" that heat and electricity contribute to overall CHP emissions, respectively. In some cases, reporters may be able to obtain emission rates for thermal and electrical generation directly from CHP managers. When possible, these figures should be used. In cases where these data are not available, reporters can estimate emissions from thermal and electrical generation on their own, using the method described below.[161]

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[160] Facilities that meet their electrical and thermal demands through on-site CHP generation should consult Part C for emission estimation methods.

[161] Plant operators may consider fuel consumption and other generation-related data proprietary information that they do not want to share. In these cases, reporters can ask their suppliers to estimate their emissions using the methods outlined in this chapter.

### 1.F.3.4.1 Indirect Emissions from Electricity and Heat Purchases from Offsite CHP Plants

**1) Estimate Purchased Electricity/Heat**

Estimate the quantities of electricity and/or heat purchased from a cogeneration supplier. Refer to bills or sales records for this information.

**2) Acquire Total Emissions and Power Production Data for the CHP Plant**

Before estimating emissions from individual heat or electricity purchases, reporters need to know the total quantities of the fuel used, and thermal and electrical power generated by the CHP plant. Reporters should contact their CHP plant manager for this information.

**3) Allocate Fuel Use to Electricity and Thermal Generation**

The first step in allocating emissions to electrical and thermal generation is to determine the fuel consumed by each process. The following formula allocates fuel consumption based on the efficiency of thermal generation and the assumption that any remaining fuel is used for electricity generation:[162]

$$\text{Fuel use}_{\text{Thermal}} = \text{Output}_{\text{Thermal}} / \text{Efficiency}_{\text{Thermal}}$$

$$\text{Fuel use}_{\text{Electricity}} = \text{Fuel use}_{\text{Total}} - \text{Fuel use}_{\text{Thermal}}$$

Where:

| | | |
|---|---|---|
| **Fuel use$_{\text{Thermal}}$** | **=** | **Fuel consumption attributable to thermal generation, measured in MMBtu** |
| **Fuel use$_{\text{Electricity}}$** | **=** | **Fuel consumption attributable to electricity generation, measured in MMBtu** |
| **Fuel use$_{\text{Total}}$** | **=** | **Total fuel consumption of CHP plant, measured in MMBtu** |
| **Output$_{\text{Thermal}}$** | **=** | **Thermal generation, measured in MMBtu** |
| **Efficiency$_{\text{Thermal}}$** | **=** | **Efficiency of thermal energy generation, expressed as a decimal percentage** |

If the efficiency of thermal energy generation (Efficiency $_{\text{Thermal}}$) is unknown, reporters may use a default value of 0.8.

4) Convert Fuel Use to Emissions

[162] Method taken from: U.S. Energy Information Administration. *Annual Energy Review 2001*.(2002), p. 370, web site: http://tonto.eia.doe.gov/bookshelf/SearchResults.asp?title=Annual+Energy+Review.

Once fuel use has been attributed to the electricity and thermal streams, reporters should refer to Part C, "Stationary Combustion," of the Technical Guidelines for guidance on how to convert fuel use to emissions from thermal and electrical power generation.

5) Estimate Emissions from Own Use

Reporters should estimate their own indirect emissions by multiplying the total emissions at the CHP plant by the ratio of their energy consumption to plant energy production. Estimate emissions using the following equations:

Emissions from Heat Consumption = [CHP Plant $\text{Emissions}_{\text{Thermal}}$ (tons)] * [Heat Consumption (MMBtu) / CHP Plant Heat Production (MMBtu)] * Transmission loss adjustment factor

Emissions from Electricity Consumption = [CHP Plant $\text{Emissions}_{\text{Electricity}}$ (tons)] * [Electricity Consumption (kWh) / CHP Plant Electricity Production (kWh)] * Transmission loss adjustment factor

Reporters should try to obtain an estimate of transmission losses for thermal and electrical power from their supplier (the CHP operator). Most suppliers will keep records of transmission losses, which vary widely based on the specific transmission system. Reporters must account for the transmission losses using the transmission loss adjustment factor, represented by the following equation:

**Transmission loss adjustment factor = 1 / (1- transmission loss (%))**

For example, if the transmission loss is 10 percent, the transmission loss factor will be equal to

**1/(1-.1) = 1/0.9 = 1.11**

If the supplier cannot provide a transmission loss factor, reporters may use a default loss rate of 10 percent for steam and hot water, and the appropriate value from Table 1.F.4 (above) for electricity.

**6) Sum Emissions**

Reporters should add emissions from purchased steam and electricity to calculate the sum of indirect emissions from CHP-generated energy use.

Ratings of emissions estimates will be assigned based on the method used, as described in Table 1.F.8.

**Table 1.F.8. Rating of Estimation Methods for Indirect Emissions from Electricity and Heat Purchases from Offsite CHP Plants**

| Estimation Method / Data Used | Rating |
|---|---|
| Measured steam/electricity consumption data used in conjunction with source-specific emission rates and a source-specific or default transmission loss factor | Same rating as given to the method used to calculate emissions (see Step 4) |
| Measured steam/electricity consumption data used in conjunction with the method provided for allocating fuel use to thermal and electrical generation, and a specific or default transmission loss factor | One value rating lower than the rating given to the method used to calculate emissions (see Step 4) |
| "Area" method estimate of steam/electricity consumption used in conjunction with source-specific emission rates and a source-specific or default transmission loss factor | Two value ratings lower than the rating given to the method used to calculate emissions (see Step 4) |
| "Area" method estimate of steam/electricity consumption used in conjunction with the method provided for allocating fuel use to thermal and electrical generation, and a specific or default transmission loss factor | D |

# Part G: Geologic Sequestration

Outline

1. Overview

2. Reporting on Carbon Dioxide Capture for Geologic Sequestration
   2.1. Inventory Approach
   2.2. Sources of Carbon Dioxide for Geologic Sequestration

3. Accounting for Sequestered Carbon Dioxide Over Time

4. Accounting Protocols for Geologic Sequestration Activities

5. Fugitive Carbon Dioxide Emissions
   5.1. Fugitive Emissions from the Extraction of Naturally Occurring Carbon Dioxide
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   5.3. Fugitive Emissions from Transport and Processing
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6. Direct and Indirect Emissions
   6.1. Energy Used for the Carbon Dioxide Capture Process
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7. Post-Injection Seepage of Carbon Dioxide to the Atmosphere

# Technical Guidelines Chapter 1, Part G: Geologic Sequestration

## 1.G.1 Overview

Carbon sequestration - the practice of capturing and storing carbon dioxide ($CO_2$) - is a relatively new option for greenhouse gas mitigation and consists of two types. First, through engineered sequestration, carbon dioxide can be captured from the point of emission and then stored in underground reservoirs, dissolved in deep oceans, or converted to rock-like solid materials. Second, through biotic (terrestrial and oceanic) sequestration, carbon dioxide can be removed from the air and sequestered in natural sinks such as trees, grasses, soils, or algae. This Part of Chapter 1 focuses on engineered carbon sequestration via the use of permanent geologic storage sites, also referred to as carbon capture and sequestration in underground reservoirs; or simply, geologic sequestration. Terrestrial sequestration is covered in Parts H and I. Engineered sequestration via ocean storage and conversion to solid materials are still in the research stage and are not covered in these Technical Guidelines.

Geologic carbon sequestration consists of the following three components:

> *Capture*: The carbon dioxide must be captured from the source of emissions. A third of the current U.S. greenhouse gas emissions are from power plants, oil refineries, and other large point sources.[163]
>
> *Transportation and Storage*: Following capture, carbon dioxide must be transported and stored. Captured carbon dioxide can be compressed and transported by a pipeline to a storage site. The United States is underlain by saline aquifers, depleted oil and natural gas reservoirs, and unmineable coal seams with the combined potential to store centuries' worth of carbon dioxide emissions.
>
> *Measurement, Monitoring and Verification*: Over the long term, stored carbon dioxide should be measured and monitored for both safety reasons and to ascertain if any leakage of the stored carbon dioxide occurs. Geologic sequestration is an emerging field; a few monitoring and measurement technologies are already in use today while others are still in the research and development phase. The guidance presented here is based on the reporting and monitoring approaches available at this time. As the field develops, the Department of Energy (DOE) will continue to review new studies and reporting rules for applicable information and, whenever appropriate, revise the reporting guidelines accordingly.

[163] A discussion of current and potential sequestration strategies can be found in Carbon Sequestration Technology Roadmap and Program Plan, February 12, 2003, U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, web site www.netl.doe.gov/publications/carbon_seq/2005_roadmap_for_web.pdf.

## 1.G.2 Reporting on Carbon Dioxide Capture for Geologic Sequestration

It is generally the reporter's responsibility to identify all anthropogenic emissions of carbon dioxide that occur from facilities owned or controlled by the reporter. For inventory reporting purposes, any carbon dioxide produced and emitted to the atmosphere as a result of combustion, reforming processes, or withdrawal from natural or man-made geologic reservoirs is considered an emission. Under these guidelines, captured carbon dioxide is also considered an emission and should be reported as such in the inventory of the entity within which the capture occurs.

Only those entities that both capture and sequester carbon dioxide within their organizational boundaries may subtract from their inventories the amount of carbon dioxide they have permanently stored in a geologic reservoir. Entities that transfer captured anthropogenic carbon dioxide for permanent storage by another entity may not subtract these emissions from their emissions inventories, but may, under the reduction guidelines described in Chapter 2, report such reductions if they have an agreement with the entity that receives and permanently sequesters these emissions.

To avoid double counting of sequestered carbon dioxide in the emissions inventory and the assessment of net emission reductions, all entities capturing carbon dioxide must include such captured gases in their assessments of net emission reductions. Any reductions resulting from permanently sequestered carbon dioxide must be calculated separately using the special method for geologic sequestration provided in Chapter 2, Section 2.4.5.6.5.

Entities that receive anthropogenic carbon dioxide from another entity do not report those emissions in their inventory, but may report a reduction equal to the amount of carbon injected into storage if they have taken the steps necessary to permanently store the carbon dioxide and monitor that sequestration, as required by Chapter 2, Section 2.4.5.6.5. Alternatively, they may enter into agreements with the entities that initially captured and transferred the carbon dioxide to permit those capturing entities to report the resulting emission reductions.

If an entity extracts or receives carbon dioxide from a naturally occurring reservoir and uses this for injection purposes, such as enhanced oil recovery (EOR), the extracted carbon dioxide must be treated as an emission in that entity's inventory. This special treatment of naturally occurring carbon dioxide is necessary to prevent entities from claiming reductions from carbon dioxide that has been tapped from a geologic reservoir.

Reporters that engage in carbon dioxide capture, transportation, and/or storage, including enhanced resource recovery (ERR), should account for all anthropogenic carbon dioxide emissions to the atmosphere that occur within the reporter's entity boundary, including any leakage of carbon dioxide from the geologic storage site and fugitive emissions from processing plants and pipelines, injection wells, and enhanced resource recovery sites. If more than one entity is involved in the capture, transportation, and storage process, each of these entities are responsible for any potential leakage or fugitive emissions that occur within their respective reporting boundaries. Reporters are not responsible for any naturally occurring carbon dioxide

emissions that may occur within the reporting boundary, but that are unrelated to the enhanced oil recovery (EOR) or storage activity.

If a reporter injects captured or recovered carbon dioxide from power generation and/or industrial processes into a geologic formation as part of an EOR project, and withdraws carbon dioxide from that or another reservoir for reuse at another site, the carbon dioxide that was recovered during that process should be counted as emissions in the inventory. Any physical leakage of captured carbon dioxide from the permanent storage site measured within the current reporting year but after the time of injection should also be treated as an emission. If an entity recycles and stores recovered carbon dioxide in another reservoir, the entity must use the special method for geologic sequestration described in Chapter 2, Section 2.4.5.6.5 in order to report an emission reduction from this activity.

If the reporter uses energy in the form of combusted fossil fuel or electricity to compress, produce, separate, or inject carbon dioxide, direct or indirect emissions from this energy use should be reported as described in Parts C and F, respectively. The reporter will also need to consider carbon dioxide that is dissolved or entrained in produced water and oil from EOR and the resulting emissions. Even if an entity captures carbon dioxide and transfers this carbon dioxide to another entity, the capturing entity must report any additional emissions from handling the captured carbon dioxide that occurs within its reporting boundary. Similarly, the entity, or entities, receiving, transporting, and/or injecting the carbon dioxide must report all direct and indirect emissions from additional energy use that occurs within that entity's boundary.

### 1.G.2.1 Inventory Approach

A geologic sequestration project begins with a source of carbon dioxide and ends with its injection and retention into a geologic storage reservoir. In reporting a sequestration project, as with all types of reporting under this system, the entity must provide accurate accounting for greenhouse gases emitted to the atmosphere from each part of the process.

Much of the information on accounting for emissions from stationary and industrial sources is covered earlier in this Chapter. This Part focuses on the accounting methodology for geologic carbon dioxide sequestration, and includes:

- Procedures for estimating fugitive emissions from carbon dioxide capture and geologic storage.
- Accounting procedures to address fugitive emissions from the use of carbon dioxide for enhanced resource recovery.
- Options for addressing potential physical leakage of carbon dioxide from storage reservoirs.

In some cases, small amounts of methane or nitrous oxides may reside in the captured gas. In such cases, fugitive emissions and physical leakage of these gases should be accounted for, using the same approaches as those outlined below for carbon dioxide.

### 1.G.2.2 Sources of Carbon Dioxide for Geologic Sequestration

Capture of carbon dioxide is most practical from highly concentrated sources. In addition to carbon dioxide from naturally occurring reservoirs,[164] there are a number of industrial and energy combustion processes that yield a highly concentrated stream of carbon dioxide, amenable to geologic sequestration. As shown in Table 1.G.1, the amount of carbon dioxide emitted from these high-concentration sources is estimated to be 185 million metric tons of carbon dioxide per year (MMmt$CO_2$/yr). These sources are:

- *Oxygen-blown gasification.* Synthetic gas (or "syngas") from an oxygen-fired gasifier is predominantly hydrogen and carbon dioxide. Carbon dioxide can be separated at high pressures from syngas prior to use, and carbon dioxide capture can be combined with sulfur removal.
- *Natural gas processing.* Carbon dioxide accounts for up to 90 percent of the gas in certain natural gas reservoirs. Carbon dioxide volume must be reduced to 1 to 2 percent to achieve the minimum Btu requirement for pipeline-quality natural gas. Chemical or physical absorbents used to remove the $CO_2$ release pure $CO_2$ or a $CO_2/SO_2$ stream upon regeneration. Typically, the carbon dioxide that is removed from the gas is vented to the atmosphere. If the carbon dioxide is captured, certain amounts of methane (up to 5%) may also remain in the captured gas and will be stored with the carbon dioxide.
- *Cement manufacture.* Pure carbon dioxide is emitted when limestone (calcium carbonate, $CaCO_3$) is heated to form clinker (calcium oxide (or lime), CaO).
- *Ammonia production.* Steam reforming converts methane ($CH_4$) to hydrogen ($H_2$) and carbon dioxide. The hydrogen is reacted with nitrogen ($N_2$) to make ammonia ($NH_3$). Chemical or physical absorbents used to facilitate this process release pure $CO_2$ or a $CO_2/SO_2$ stream upon regeneration.
- *Hydrogen manufacture.* Light hydrocarbons are reacted with steam to form a mixture of hydrogen and carbon dioxide. Carbon dioxide is separated from the hydrogen product and a highly concentrated stream of carbon dioxide is released.
- *Ethanol manufacture.* Biogenic carbon dioxide is produced and vented during corn fermentation.
- *Helium production.* Carbon dioxide accounts for up to 90 percent of the gas found in certain helium reservoirs. Helium and carbon dioxide must be separated prior to helium use.
- *Advanced coal-fired power generation.* Integrated gasification combined cycle (IGCC) power plants emit a sequestration-ready[165] stream of carbon dioxide, as would FutureGen-type[166] plants which produce both electricity and hydrogen.

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[164] Naturally occurring $CO_2$ is often harvested for use in enhanced oil recovery operations.
[165] In some commercially available gasification processes (e.g., the proprietary ChevronTexaco Gasification Process), a high-pressure stream of $CO_2$ can be configured readily to be taken out of the shift reactor. At high pressure, this stream will require little compression for reinjection and storage.
[166] For more information on the FutureGen initiative, please visit the web site http://www.netl.doe.gov/technologies/coalpower/futuregen/.

**Table 1.G.1. Current High-Concentration Carbon Dioxide Vents in the United States**

| Type of $CO_2$ Vent | Number of Vents in the U.S. in 2000 | Aggregate $CO_2$ emissions in 2000 ($MMmtCO_2$) |
|---|---|---|
| Oxygen-blown gasification | 11 | 55 [1] |
| Natural gas processing | 580 | 55 [2] |
| Cement manufacture | 37 | 40.3 [3] |
| Ammonia production | 40 | 16.1 [4] |
| Hydrogen manufacture | 40 | 13.9 [5] |
| Ethanol manufacturer | 40 | 4.4 [6] |
| Helium production | none | 0 |
| Advanced coal-fired power generation | none | 0 |
| **Total** | | **184.7** |

[1] SFA Pacific/Gasification Technologies Council, Gasification Database, 2001.
[2] Combined EIA estimate for emissions from natural gas processing (Emissions of GHGs in the U.S. 2000, Table 4) with emissions from selected large volume point sources supplied by API. Number of vents is from the Natural Gas Supply Association (2005).
[3] EPA Inventory of U.S. GHG Emissions and Sinks, 2002, Emission Factor Documentation AP-42, Section 11.6.
[4] EPA Inventory of U.S. GHG Emissions and Sinks, 2002, Emission Factor Documentation AP-42, Section 5.2; Twenty sources of less than 0.02 MMmtC/yr were omitted.
[5] Refinery Capacity Data as of January 1, 2001. Database file "RefCap01.dpf," Energy Information Administration (EIA), Form EIA-820, "Annual Refinery Report"; 3,243 MMSCFD $H_2$ production capacity converted to $CO_2$ using the factor 0.26 scf highly pure $CO_2$ vented per scf $H_2$ produced; 24 sources of less than 0.02 MMmtC/yr were omitted.
[6] Renewable Fuels Association web site, 1.63 billion gallons of ethanol produced in 2001; conversion factor, 3 kg $CO_2$ per gallon ethanol from Kansas Geological Survey; 35 sources of less than 0.02 MMmtC/yr were omitted. Note that carbon dioxide from biomass fermentation or combustion would be considered biogenic, and would not contribute to total reported emissions under the Voluntary Reporting Program or national inventories. However, sequestration of biogenic carbon would be considered a "negative emission."

## 1.G.3 Accounting for Sequestered Carbon Dioxide Over Time

When carbon dioxide is injected into a geologic formation, it is expected that it will be sequestered permanently, barring any physical disruption of the reservoir or injection wells.

When a geologic sequestration project is undertaken for the sole purpose of emissions mitigation, the accounting is straightforward. The amount of carbon dioxide emitted may be determined as the quantity of carbon dioxide lost as fugitive emissions during the capture, transport, and injection of carbon dioxide. Once injection of the captured carbon dioxide is completed and the wells are sealed, the reporter will be responsible for any potential physical leakage of carbon dioxide occurring every year thereafter. The reporter should use one of the following two methods for determining post-injection physical leakage:

a) Actively monitor and maintain the site, measuring actual carbon dioxide losses from the well heads and the storage reservoir, which would then be treated as emissions in the year in which they occur. Section 1.G.7 describes methods for tracking post-injection leakage.

b) Apply a site-specific monitoring plan already approved by a relevant Federal or state regulatory agency for the purpose of tracking carbon dioxide seepage/leakage.

If the entity chooses not to monitor the storage site for any potential post-injection physical leakage, it must assume that the entire stock of carbon dioxide will be reemitted to the atmosphere, and include this emission in the reporter's inventory for that year.

Use of carbon dioxide for enhanced resource recovery presents a special case in evaluating the amount of carbon dioxide released over time. Sources that should be counted towards the inventory include the amount of carbon dioxide released during injection, extraction and re-injection, and the amount released after the project has ended.

Emissions reporting responsibilities are the same as for any other geologic sequestration project; while enhanced recovery operations are underway, the reporter must determine fugitive losses of carbon dioxide each year. When enhanced resource recovery operations are concluded, and each year thereafter, the reporter must determine any physical leakage using one of the two methods outlined above. If the entity decides not to monitor post-injection leakage, it must include the entire stock of injected carbon dioxide in the inventory for that year.

## 1.G.4 Accounting Protocols for Geologic Sequestration Activities

As discussed in Section 1.G.2, above, several tools exist for reporters to estimate their greenhouse gas emissions. At this time, no calculation protocols specifically address greenhouse gas emissions from geologic sequestration practices, although the IPCC is in the process of developing a methodology for carbon capture and storage projects. Moreover, the IPCC Special Report on Carbon Dioxide Capture and Storage includes a chapter on issues related to emissions inventories and accounting that may be useful to reporters. Existing protocols for other industries may also be utilized. While not written with carbon dioxide sequestration in mind, these estimation methodologies may provide guidance in calculating emissions from various aspects of geologic sequestration, including transportation, handling, and fugitive emissions. For example, the California Climate Registry recommends reviewing relevant methodologies and/or calculations with technical assistance providers or other environmental experts, and refers to several resources for reporters to develop a means of estimating fugitive emissions from natural gas transport and distribution, and coal mining.[167]

The following subsections summarize existing protocols for estimating emissions from these various aspects of geologic sequestration projects:

- Fugitive emissions from the processing, transport, injection, and withdrawal of carbon dioxide;
- Direct and indirect emissions from increased energy use resulting from sequestration; and
- Post-injection seepage of carbon dioxide to the atmosphere.

[167] California Climate Action Registry. "California Climate Action Registry General Reporting Protocol." October 2002. Page 9-1. www.climateregistry.org/docs/PROTOCOLS/general_reporting_protocol_102102.pdf

For each type of carbon sequestration project, measurement-based methods available to reporters are explained, as well as calculation-based protocols, if available. As in previous Parts of these Technical Guidelines, each methodology is rated. In all cases, continuous emissions monitoring and mass balance calculations based on measured emissions data are rated "A." At this time, standard emissions factors for the capture, transport, and injection of carbon dioxide have not been developed. If developed in the future and approved by DOE, these factors would be appropriate to use for a "B" or "C" rating.

## 1.G.5 Fugitive Carbon Dioxide Emissions

This section explains how to estimate the amount of carbon dioxide lost to the atmosphere during the capture, processing, transport, injection, and extraction of carbon dioxide. This includes a discussion of fugitive emissions from the production of carbon dioxide both from naturally occurring reservoirs and from the waste stream processes associated with power generation and industrial processes. In the case of ERR, particularly EOR, naturally occurring carbon dioxide is more commonly used, but a few projects also use carbon dioxide captured from industrial processes or natural gas processing. It is unlikely that naturally occurring carbon dioxide would be harvested for any other purposes than enhanced resource recovery activities. Carbon dioxide produced as a byproduct of industrial processes and power generation could be sequestered via enhanced resource recovery practices, as well as in saline formations.

### 1.G.5.1 Fugitive Emissions from the Extraction of Naturally Occurring Carbon Dioxide

Reporters could use existing monitoring techniques, such as flow meters, to measure the amount of carbon dioxide lost from the natural geologic reservoirs, combined with periodic (at least annual) analyses of gas composition to determine the carbon dioxide content. This approach would be rated "A."

Calculating the fugitive emissions from a natural reservoir using a mass balance method based on the difference of measurements of the carbon dioxide contained in the reservoir before and after withdrawal, minus the amount extracted, (Equation 1) is rated "B."

$$E_{fug} = C_1 - C_2 - C_3 \quad (1)$$

**Where:**

| | | |
|---|---|---|
| $E_{fug}$ | = | **Amount of fugitive $CO_2$ from the geologic reservoir** |
| $C_1$ | = | **Amount of measured $CO_2$ contained in the reservoir before extraction** |
| $C_2$ | = | **Amount of measured $CO_2$ contained in the reservoir after extraction** |
| $C_3$ | = | **Amount of measured CO2 extracted from the geologic reservoir** |

### 1.G.5.2 Fugitive Emissions from the Extraction of Carbon Dioxide from Anthropogenic Sources

There are several industrial and energy combustion processes that emit a relatively concentrated stream of carbon dioxide that is suitable for use in geologic sequestration. These sources, as described above, are oxygen-blown gasification, natural gas reprocessing, cement manufacture, ammonia production, steam reforming in an oil refinery, ethanol manufacture, helium production, and advanced coal-fired power generation. Reporters should refer to Parts C and E of this Chapter of the Technical Guidelines for a discussion and rating of methods for estimating carbon dioxide produced from each of these sources.

Not all carbon dioxide is collected during the capture process; some will instead be released to the atmosphere. Arriving at the correct inventory of emissions after capture may involve some subtractions to determine the correct amount of carbon dioxide emitted. Estimation methods based on continuous emissions monitoring will automatically reflect the amount captured and emitted while mass balance approaches based on the amount of fuel combusted will have to be adjusted for the amount captured. The following estimation methods can be used for determining the amount of carbon dioxide that remains in the waste stream if the reporter is not using a continuous emissions monitoring system to determine carbon dioxide emissions.

Calculating the difference in the direct measurements of carbon dioxide emitted from the emissions source, downstream from the capture technology and upstream from the capture technology, will yield the net carbon dioxide released to the atmosphere (Equation 2). This method of mass balance merits an "A" if the calculation is based on continuous emissions monitoring or flow meter data. It rates a "B" if based on annual emissions data.

$$E_{cap} = E_{upstream} - E_{downstream} \quad (2)$$

**Where:**

| | | |
|---|---|---|
| $E_{cap}$ | = | **Fugitive $CO_2$ emissions during the capture process** |
| $E_{upstream}$ | = | **Direct measurement of $CO_2$ in emissions stream upstream from capture technology** |
| $E_{downstream}$ | = | **Direct measurement of $CO_2$ in emissions stream downstream from capture technology.** |

Calculation of carbon dioxide emissions may be estimated based on the manufacturer's specifications for the carbon dioxide capture technology (Equation 3). This method is rated "C" because there are no real measurements of carbon dioxide emissions captured.

$$E_{cap} = (1 - \eta)E_s \quad (3)$$

**Where:**

| | | |
|---|---|---|
| $E_{cap}$ | = | **Fugitive $CO_2$ emissions during the capture process** |
| $\eta$ | = | **Published efficiency of $CO_2$ capture technology** |

$E_s$ = **Emissions from source, without capture process**

### 1.G.5.3 Fugitive Emissions from Transport and Processing

Transportation of carbon dioxide from the source to the injection site may result in some leakage to the atmosphere. Carbon dioxide may be transported by tank or pipeline, and due to material weaknesses of the system, some carbon dioxide may be released during this process. If the carbon dioxide is transported by tank or aboard a truck, ship, or other vehicle, reporters must determine the additional emissions from vehicular transport. For instructions on reporting emissions from the mobile sources themselves, the reporter should refer to Part D on transportation.

There are several options available to reporters to quantify the amount of carbon dioxide lost during transport.

Calculating the difference in the amount of carbon dioxide traveling between points in pipeline transit (Equation 4) is rated "A" for determining the amount of carbon dioxide lost to the atmosphere. Flow meters should be set up to measure the amount of gas supplied to the pipeline at the source and at the endpoint of the pipeline. The effect of differences in the surrounding temperatures at the beginning and endpoint would also need to be taken into account to adjust volumetric values according to cooler or warmer climates.

$$E_{trans} = C_{in} - C_{out} \quad (4)$$

**Where:**

$E_{trans}$ = **Fugitive $CO_2$ emissions from transportation via pipeline**

$C_{in}$ = **Direct measurement of $CO_2$ at pipeline input**

$C_{out}$ = **Direct measurement of $CO_2$ at pipeline endpoint**

Calculating the difference in the amount of carbon dioxide contained in a tank (Equation 5), based on a measurement taken at the time the tank is filled and a measurement taken at the point the tank is delivered to the injection site, to determine the amount of carbon dioxide lost to the atmosphere (Equation 5), is also rated "A."

$$E_{trans} = C_{fill} - C_{del} \quad (5)$$

**Where:**

$E_{trans}$ = **Fugitive $CO_2$ emissions from transportation via tank**

$C_{fill}$ = **Direct measurement of $CO_2$ at source, filling of tank**

$C_{del}$ = **Direct measurement of $CO_2$ at pipeline, delivery of tank**

Calculating the difference in the amount of carbon dioxide traveling between points in pipeline transit is rated "B" if determined by annual measurements of carbon dioxide in the pipeline at the place of capture or extraction and the point of injection.

Calculating the difference in the estimated amounts of carbon dioxide sent to the pipeline and taken out of the pipeline will yield the amount of carbon dioxide lost. The amount of carbon dioxide input into the pipeline may be estimated by the manufacturer specifications for carbon dioxide capture technology efficiency (Equation 3, above). The amount of carbon dioxide output by the pipeline may be estimated to be the amount of carbon dioxide injected for ERR. This case of estimating the amount of carbon dioxide emissions from pipeline transportation without measuring any carbon dioxide quantities (Equation 6) is rated "C."

$$E_{trans} = E_{cap} - C_{req} \quad (6)$$

**Where:**

**$E_{trans}$ = Fugitive $CO_2$ emissions from transportation via pipeline**

**$E_{cap}$ = Estimation of $CO_2$ capture based on Equation 3, above**

**$C_{req}$ = Amount of $CO_2$ injected for enhanced resource recovery**

Estimating fugitive emissions from carbon dioxide pipelines may also be accomplished by using Environmental Protection Agency (EPA) emissions factors for volatile organic compounds (VOCs). Those factors serve as the basis of the AP-42 petroleum refinery emissions factors and API *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* to estimate fugitive VOC emissions from pipelines. Table 1.G.2 provides these emissions factors.

### Table 1.G.2. EPA Average Refinery Emissions Factors

| Component | Emissions Factor, kg VOC/hr/component | Emissions Factor, mt VOC/hr/component |
|---|---|---|
| Valves | 2.68E-02 | 2.68E-05 |
| Compressor Seals | 6.36E-01 | 6.36E04 |
| Pressure Relief Valves | 1.60E-01 | 1.60E-04 |
| Connectors | 2.5E-04 | 2.5E-07 |
| Open-ended Lines | 2.3E-03 | 2.3E-06 |
| Sampling Connections | 1.50E-02 | 1.50E-05 |

Source: EPA, *Protocol for Equipment Leak Emission Estimates*, Table 1-1 (1995), web site: www.epa.gov/ttn/chief/efdocs/equiplks.pdf.

The API *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* provides equations to be used in determining the average emissions factor based on the EPA average refinery emissions factors. It is reproduced here, adjusted to determine carbon dioxide emissions (Equation 7).

$$E_{trans} = EF_i \quad (7)$$ [168]

**Where:**

**$E_{trans}$ = Fugitive $CO_2$ emissions from pipeline transport**

**$EF_i$ = EPA emissions factor for component, i**

[168] Based on Equations B-8, B-9 and B-10. American Petroleum Institute (API), *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry, 2004*, web site: api-ec.api.org/filelibrary/ACF41C.pdf.

**i = Pipeline component**

Equation 7 assumes that the transport pipeline is transporting pure carbon dioxide. Fugitive carbon dioxide emissions from valves, compressor seals, connectors, open-ended lines and sampling connections can be derived by applying Equation 7 and inserting the average emissions factors supplied in Table 1.G.3. Because the emissions factors supplied in Table 1.G.3 are based on VOC emissions instead of carbon dioxide emissions, use of this method is rated "D."

### 1.G.5.4 Fugitive Emissions from Injection and Extraction for Enhanced Resource Recovery (ERR)

Many enhanced resource recovery operations recycle carbon dioxide used in the recovery process by re-injecting it into the same well or transferring it to a new recovery site. Some carbon dioxide might be lost to the atmosphere during this process of recycling; it may be emitted when injected or when extracted. The following subsections describe how to account for any potential fugitive emissions from the recycling of carbon dioxide for enhanced resource recovery.

Use of a monitoring system to measure the loss of carbon dioxide during recycling is rated "A."

Calculating the amount of carbon dioxide lost during the reporting period as the difference between the amount of carbon dioxide needed for enhanced resource recovery and the estimated amount of carbon dioxide stored is rated "D" (Equation 8). In this case, no measurements are made, but rather, amounts of carbon dioxide in storage and used for ERR are based on historical data and process needs, respectively.

$$E_{rec} = C_{store} - C_{req} \quad (8)$$

**Where:**

**$E_{rec}$ = Emissions during recycling of $CO_2$ from storage**

**$C_{store}$ = Amount of $CO_2$ in storage at the beginning of the reporting period**

**$C_{req}$ = Amount of $CO_2$ required for ERR during the reporting period**

## 1.G.6 Direct and Indirect Emissions

### 1.G.6.1 Energy Used for the Carbon Dioxide Capture Process

Energy is used in all stages of carbon dioxide capture and geologic sequestration. For example, the energy used to capture carbon dioxide in a coal-fired plant lowers the plant's net energy output because additional energy is required to power the capturing equipment. In the case of a manufacturing plant, the additional energy requirement for carbon dioxide capture increases the plant's direct and indirect carbon dioxide emissions from fossil fuel combustion. Another potential emission source includes the fuel used for compressing captured carbon dioxide to the

properties of pipeline gas. Reporters should refer to Parts C and F, which provide guidance on reporting emissions from onsite electricity generation and/or indirect emissions from offsite electricity generation, respectively, for further discussion.

### 1.G.6.2 Energy Used for the Carbon Dioxide Injection Process

Carbon dioxide injection requires energy to operate the compression and injection equipment. This additional energy could be generated onsite or offsite. The changes in emission levels due to increased direct and indirect energy use will be addressed when an entity accounts for its overall emissions from stationary combustion and purchase of electricity/heat from indirect sources. Reporters should refer to Parts C and F for more detailed guidance on measuring or calculating emissions from stationary combustion and estimating indirect emissions from offsite electricity and heat generation.

Not all injection equipment will be powered by electricity; some equipment might be fueled by natural gas, fuel oil, propane, or another fuel. In this case, direct monitoring is a possibility, as is determining emissions based on the known energy use and efficiency of the equipment. Reporters should refer to Part C for protocols to calculate emissions from fuel combustion.

### 1.G.6.3 Energy Used for Extraction for Enhanced Resource Recovery (ERR)

The production of oil resulting from ERR requires considerable energy for pumping additional fluids, power boilers, gas compression and dehydration, and re-injection and recycling of carbon dioxide. Similar to the energy use for the injection process, the changes in emission levels due to increased direct and indirect energy use during ERR will be addressed when an entity accounts for its overall emissions from stationary combustion and purchase of electricity/heat from indirect sources. Reporters should refer to Parts C and F for more detailed guidance on measuring or calculating emissions from stationary combustion and estimating indirect emissions from offsite electricity and heat generation.

Not all ERR production and re-injection equipment will be powered by electricity; some equipment might be fueled by natural gas, fuel oil, propane, or another fuel. In this case, direct monitoring is a possibility, as is determining emissions based on the known energy use and efficiency of the equipment. Reporters should refer to Part C for protocols to calculate emissions from fuel combustion.

## 1.G.7 Post-Injection Seepage of Carbon Dioxide to the Atmosphere

Monitoring at current carbon dioxide storage sites indicates that physical leakage rates of carbon dioxide are very small or nonexistent for geologic formations, when they are chosen with care. However, this does not prevent any seepage of carbon dioxide from occurring in the future and entities are responsible for monitoring and reporting such seepage during the reporting year that the emissions occur.

Many options are available to estimate the amount of carbon dioxide that be released from permanent geologic formations over time. Many of these methods are still being tested for effectiveness, uncertainty, and cost. As a result, there are no standard protocols or established networks for monitoring leakage of carbon dioxide at this time.[169] In general, available methods for monitoring stored carbon dioxide focus on two areas: 1) monitoring of lateral reservoir migration of carbon dioxide over time to assess the integrity of the storage reservoir; and 2) monitoring of carbon dioxide leakage outside of the reservoir due to vertical migration. Examples of each type of monitoring method are provided below, with some techniques fitting into both areas.[170] Current capture and storage projects, such as the Weyburn EOR project in Saskatchewan, Canada, typically use a combination of these two monitoring types. A monitoring plan that uses 4D seismic surveys, reservoir pressure monitoring, formation fluid monitoring, shallow water sampling (if present), and soil gas surveys is rated A. A monitoring plan that includes periodic (at least annual) monitoring using one or more direct measurement techniques in each of the two areas is rated B. A monitoring plan that relies on measurement techniques in only one area is rated C.

Area 1: Monitoring techniques for tracking lateral migration of carbon dioxide:

- *Seismic surveys*: 2D, 3D, wellbore-to–surface, and cross-wellbore seismic surveys are sometimes employed in the site characterization process, but can also be effective in identifying the location of the injected carbon dioxide in the reservoir.
- *Gravimetric measurements*: Gravimetric measurements can be used to locate carbon dioxide already injected in the reservoir.
- *Wellhead and formation fluid sampling*: Periodic fluid sampling can be used to verify where the carbon dioxide is in the formation.

Area 2: Monitoring techniques for tracking carbon dioxide leakage outside the reservoir:

- *Radioisotope tracer monitoring of cement integrity*: The casings of injection wells are known to be the most vulnerable spot for leaks. Periodic measurements of cement integrity with gamma-ray tools have been shown to be effective in detecting and preventing leakage.
- *Seismic surveys*: repeat 3D (i.e.4D) seismic surveys can be used to detect leakage out of the reservoir as well as determine the lateral extent of the carbon dioxide in the reservoir.
- *Reservoir pressure monitoring*: Careful logging of reservoir pressures will allow for detection of any carbon dioxide migration outside the injection reservoir. (Note: this technique may not be applicable to storage in saline aquifers.)
- *Establishment of monitoring wells*: Dedicated monitoring wells can be employed for measurement of reservoir pressure and sampling for direct detection of carbon dioxide or tracers.
- *Microseismic monitoring of rock response to injection*: Monitoring of seismic activity during and after injection can predict potential seepage to the atmosphere.

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[169] Intergovernmental Panel on Climate Change (IPCC). *IPCC Special Report: Carbon Dioxide Capture and Storage. Technical Summary*. Chapter 5 (2005).
[170] Benson, S.M., Myer, L. *Monitoring to Ensure Safe and Effective Geologic Sequestration of Carbon Dioxide.* IPCC Workshop on Carbon Dioxide Capture and Storage.

- *Use of natural or induced tracers*: Radioisotope tracers can be injected into the formation along with the carbon dioxide, giving it a "signature" and allowing for easy detection of any carbon dioxide that migrates outside the injection reservoir.
- *Water sampling for carbon speciation and stable isotopes*: Periodic sampling of water in overlying aquifers can be used to verify that the carbon dioxide has remained in the injection reservoir.
- *Fracture analysis and flow simulations*: Simulations are often used as part of the site characterization process, but can also be powerful tools for leak prevention.
- *Ecosystem impact analyses*: Soil gas surveys, detailed observations of plant communities, ground water quality analysis and other techniques can be used to detect any signals that carbon dioxide has seeped from the reservoir.

The ratings for the various methods for measuring and estimating carbon dioxide emissions related to geologic sequestration are summarized in Table 1.G.3.

### Table 1.G.3. Summary of Ratings for Geologic Sequestration of Carbon Dioxide

| ITEM | RATING |
|---|---|
| **Fugitive emissions from the extraction of naturally occurring $CO_2$** | |
| Direct measurement and at least annual content analysis of gas | A |
| Mass balance based on before-and-after measurements, minus amount extracted *(Equation 1)* | B |
| **Fugitive emissions during the extraction of $CO_2$ from anthropogenic sources** | |
| Difference between upstream and downstream measurements based on CEM or flow meter data *(Equation 2)* | A |
| Difference between upstream and downstream measurements based on annual emissions data *(Equation 2)* | B |
| Manufacturer's specifications for capture technology employed *(Equation 3)* | C |
| **Fugitive emissions during transport and processing** | |
| Direct actual measurements at pipeline beginning and endpoint *(Equation 4)* | A |
| Direct actual measurements at tank fill and delivery *(Equation 5)* | A |
| Annual measurements at pipeline beginning and endpoint *(Equation 4)* | B |
| Estimating without direct measurement *(Equation 6)* | C |
| Use of EPA VOC emissions factors *(Equation 7)* | D |
| **Fugitive emissions of $CO_2$ during injection and extraction for enhanced resource recovery** | |
| Monitoring system for direct $CO_2$ loss measurement | A |
| Difference in $CO_2$ needed and $CO_2$ stored *(Equation 8)* | D |
| **Post-injection seepage of carbon dioxide to the atmosphere** | |
| Monitoring plan using 4D seismic, reservoir pressure monitoring, formation fluid monitoring, shallow water sampling (if present) and soil gas surveys | A |
| Monitoring plan using one or more measurement techniques in both categories | B |
| Monitoring plan using measurement techniques in only one category | C |

## Technical Guidelines for Voluntary Reporting of Greenhouse Gases Program
## Chapter 1, Emission Inventories

# Part H: Agricultural Emissions and Sequestration

Outline

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# Technical Guidelines Chapter 1, Part H: Agricultural Emissions and Sequestration

## 1.H.1 Overview

This section supports and supplements the General Guidelines for reporting greenhouse gas information under Section 1605(b) of the Energy Policy Act of 1992 (EPAct). The General Guidelines provide the rationale for the Voluntary Reporting of Greenhouse Gases Program and overall concepts and methods to be used in reporting. The reader should be familiar with the contents of the General Guidelines and Chapter 1 Part A of the Technical Guidelines before proceeding to the specific guidance in this Part on the agricultural sector's methods and data requirements. Other Parts in this Chapter address the sectors of electricity, residential and commercial buildings, industry, transportation, and forestry.

This Voluntary Reporting of Greenhouse Gases Program has been designed to be flexible, and includes a variety of methods for making estimates of emissions and sequestration. The methods range from simple and inexpensive to complex and costly, and reporters may choose the simplest methods that provide estimates with an accuracy that meets reporting objectives. For example, "default" emission and sequestration factors are provided for those who wish to report using data that are typical for agricultural activities in a region, but may not represent a specific entity. Guidance is provided for developing methods that are more specific to an entity, including approaches that allow reporters to calculate a known accuracy. The default factors that this document provides can be used to convert existing data directly into estimated quantities of emissions or sequestration. The intent of the default emission and sequestration factors is to simplify the reporting process, not to discourage reporters from developing their own emissions estimates.

This section provides guidance on identifying and quantifying emissions and sequestration from agricultural sources and sinks. Throughout this section, reference is made to the Practice Standards and Specifications of the U.S. Department of Agriculture's (USDA) Natural Resources Conservation Service (NRCS). Each practice referenced has a national standard and local specifications designed to ensure quality standards. Practice standards and specifications are available in the Field Office Technical Guide, available at the NRCS website: www.nrcs.usda.gov/technical/efotg/. All emission reductions or sequestration reported should be consistent with applicable conservation treatment of the land.

## 1.H.2 Emission Sources and Sinks

Greenhouse gas (GHG) emissions may occur from livestock and/or crop production. GHG source categories from livestock include enteric fermentation and livestock waste,[171] and from crop production include residue burning, rice cultivation, nutrient applications, and lime applications. Crop production and grazing land management can also be a source or sink of

[171] Livestock waste includes manure and urine.

carbon dioxide ($CO_2$): the oxidation of organic matter in soil causes carbon dioxide emissions from soils. Land management practices including tillage, rotations, fallowing, and cover crops influence the rates of organic soil matter oxidation. Carbon sequestration occurs when management practices increase the amount of organic carbon contained in soil and/or promote growth of long-lived perennial biomass (e.g., trees and permanent grasses).

The methods described below can be used to develop emissions estimates for each of the livestock and crop production sources described above. Methods are also provided for estimating carbon flux in soils. For each source and sink category, guidance is provided for at least one method, and where possible, additional methods for estimating emissions and carbon flux are explained. In addition, explanations of the uncertainties associated with each estimation methodology are provided to assist in providing assessments of its relative reliability. Finally, estimation method ratings are given on an ordinal scale; the recommended method is the best that is currently available even though it may be relatively uncertain. The estimation method ratings can be used to calculate entity scores following guidance provided in Part A of this Chapter.

## 1.H.3 Estimation Methods

There are several different approaches to estimating greenhouse gas emissions and carbon sequestration in agricultural operations. Because agricultural emissions and sequestration occur over relatively large geographic areas and, for many farm activities and land use decisions, vary in magnitude depending on specific conditions, they are often difficult to measure directly. In many cases, the most reliable and cost-effective methods are a combination of point sampling with a statistically derived expansion factor. This approach allows for the calculation of a standard error as an estimate of certainty. In some cases, even point scale measurement is prohibitively expensive and the most cost effective means of estimation is through the use of site-specific inputs, such as acres and number of head of livestock, and default equations.

### 1.H.3.1 Direct Measurement

The most accurate way to estimate GHG emissions and carbon flux is through continuous direct measurement. Direct measurement uses special instruments that monitor the flow of gases from the source into the atmosphere. Many, but not all, GHG emissions sources in agriculture can be measured with such instrumentation. For example, techniques exist to measure methane ($CH_4$) emissions from enteric fermentation in livestock, including controlled livestock chambers and pastures fitted with gas flux towers. Flux chambers can also be used to monitor the amount of nitrous oxide ($N_2O$) and/or carbon dioxide gas emitted from a small plot of land, metering the products of nitrogen and carbon cycles. Emissions from livestock waste can be readily monitored in certain circumstances, (e.g., covered anaerobic lagoons fit with gas flux meters), although where waste is not managed in a confined system (e.g., manure deposited directly in pasture, range, or paddock), it is difficult if not impossible to directly measure emissions. Techniques for continuous or periodic direct measurement of GHG emissions are practical and necessary when conducting research and may be incorporated into large scale projects as a means of developing more site specific emission factors.

At the farm level, continuous direct measurement of GHG emissions is often costly and therefore not feasible. Direct measurement techniques, however, can be used to sample emission sources and derive data to improve more approximate estimation techniques such as those described below. The resulting hybrid designs may provide reasonable accuracy and feasibility.

Carbon flux over a large land area is virtually impossible to measure directly, although net fluxes in soil carbon can be closely approximated by directly measuring the carbon content of soils over time. Net carbon fluxes (either positive or negative) are inferred as the change in carbon stocks over time.

### 1.H.3.2 Process Models

Models that estimate ecosystem processes, such as the nitrogen and carbon cycles, are becoming increasingly available. Process models typically rely on a series of input data that research has shown to be important drivers of the process being modeled. These models may be mathematically simple or complex depending on the nature of the process. In some instances only a few inputs are needed to estimate the outputs of a process; in others, multiple inputs over different spatial and temporal scales are required. Input data can be physical variables such as temperature, precipitation, elevation, and soil nutrient levels, or biological variables such as soil microbial activity and plant diversity.

The accuracy of process models is variable and depends on the robustness of the model and the accuracy of the inputs. Model robustness can be empirically determined through validation where projected outputs are compared to direct measures. The decision to use process models will depend on the resources available and the existence of appropriate models or the tools to develop a reporter's own models.

### 1.H.3.3 Inference

The simplest estimation methods are what these guidelines refer to as "inferences." The inference approach relies on input data multiplied by State, regional, or national emissions/sequestration factors that approximate emissions/sequestration per unit of the input. For example, to obtain an entity-level estimate of $CH_4$ emissions from enteric fermentation, emissions may be estimated by multiplying the number of dairy cattle the entity owns by an emission factor that reflects how much $CH_4$ is emitted per head of dairy cattle.

The accuracy of inference approaches varies depending on the specificity of the emission factor applied and the accuracy of the input data. Factors used to estimate emission and sequestration sources and sinks in agriculture rarely capture the full complexity of underlying biological processes, which are driven by a number of external variables such as climate, soil conditions, livestock diet, and livestock genetics. An inference approach thus generally yields estimates that are less accurate than those developed using site-specific approaches, although the estimates can be improved by using the most specific emissions factors available (i.e., matched to the climate region, livestock category, soil type, etc.).

The accuracy of the inference approach also depends on the inherent variability of the sources being estimated. For some agricultural sources, regional or national emission factors provide emissions estimates with relatively low uncertainty, while for other sources emission estimates will have relatively high uncertainty.

These guidelines provide GHG emission and carbon sequestration factors for each source and sink category in agriculture. In some cases the factors are relatively generic; in others they are specific to States, regions, and management practices.

### 1.H.3.4 Hybrid Estimation Approaches

In selecting an estimation method for a particular GHG source or sink, entities will often need to weigh the costs, feasibility, and accuracy of the different approaches.
A promising approach to balance these considerations is to combine direct measurement or process models into an inference-based approach. The accuracy of the inference approach can be greatly improved by developing emission and sequestration factors that specifically characterize the reporter's operating conditions.

Direct measurement may be used to develop specialized emission/sequestration factors that match an entity's conditions. This involves sampling source categories within an entity rather than continuous direct measurement of all sources, which reduces resource requirements while improving the specificity of emission factors. The samples are used to derive emissions factors for use with simple input data. Process models may also be used to derive specialized emissions coefficients for entities, provided they are determined by the reporter to produce robust estimates of emissions.

### 1.H.3.5 Rating Scale for Estimation Methods

Multiple estimation methods may be available for a single emissions source or sink category. In general, these methods will vary in accuracy, reliability, verifiability and practical application. The revised Voluntary Reporting of Greenhouse Gases Program includes a system for ranking alternative estimation methods that encourages entities to use the most accurate method suitable for their circumstances. The ranking system is discussed in detail in Chapter 1, Part A, Section 4 of the Technical Guidelines.

The ranking system provides four possible ratings (A-D) that are applied to a given estimation method for a specific source or sink. For any given source or sink, an A, B, C, or D rated method may not be available.

In these inventory guidelines, the best available methods balance accuracy and practicality in preparing entity-level annual greenhouse gas inventories of agricultural sources and sinks. The methods often rely on a combination of site-specific data and default data based on national averages. Estimation accuracy is dependent, in part, on the specificity of entity data inputs and how well entity conditions match national averages. Using measured entity data, rather than estimates or samples, will improve estimates and is encouraged.

Ratings for each method are clearly indicated in the guidelines below. Methods are presented in order from lowest to highest rated. This is different from other Parts in this Chapter, where the highest rated method is presented first. In many of the methods detailed below, the higher rated methods build on default data used by the lower rated method, lending to a structure that begins with the basic estimate first.

## 1.H.4 Category-Specific Estimation Guidance

### 1.H.4.1 Livestock Sources

Entities reporting emissions from animal operations will need to estimate $CH_4$ emissions from enteric fermentation and $CH_4$ and $N_2O$ emissions from livestock waste. The first step in both of those calculations is to compile information on the entity's animal populations. Because region-specific emission factors are provided in several of the methods, entities will need to assess their region(s) according to definitions provided in this section.

#### 1.H.4.1.1 Characterizing Animal Populations and Climate Regions

Each method for estimating emissions from livestock requires an entity to first characterize livestock populations by determining the number of animals the entity owns within specific livestock categories. The level of detail of the characterization varies depending on the estimation method. Only a simple characterization is needed for sheep, goats, and horses for all methods. Entities should determine how many they have of each of these animal categories.

Methods yielding more accurate estimates typically require detailed characterizations of one or more of the following: beef cattle, dairy cattle, swine, and poultry. Descriptions of livestock categories for each of those groups are provided in Table 1.H.1.

Environmental conditions in different climate regions may affect GHG emissions from livestock sources. Therefore, in addition to characterizing livestock populations, entities will need to determine their climate region(s) to use the default emission factors provided. Most agricultural entities will be within a single climate region. For entities with operations across the United States, livestock emissions estimates need to be made separately for each climate region. Climate regions are defined differently throughout the livestock section depending on the estimation method. Use the definitions in Tables 1.H.1, 1.H.2, and 1.H.3 when selecting emission factors to use in the inference-based approaches.

**Table 1.H.1. Definitions of Livestock Categories**

| Livestock Category | Description |
|---|---|
| Beef Cattle/Cows | Beef cows that have calved |
| Replacement Heifers (0-12 mo.) | Beef cow replacements age 0-12 months |
| Replacement Heifers (0-24 mo.) | Beef cow replacements age 12-24 months |
| Bulls | Bulls (>= 500 lbs.) |
| Steer stockers | Feedlot steer, >= 500 lbs. |
| Heifer stockers | All heifers other than feedlot heifers (>= 500 lbs.) |

| Livestock Category | Description |
|---|---|
| Steer feedlot | Steer on diets fed to animals on feedlots |
| Heifer feedlot | Heifers on diets fed to animals on feedlots |
| Steer step-up | Steers on diets fed to animals entering feedlots |
| Heifer step-up | Heifers on diets fed to animals entering feedlots |
| | |
| Dairy Cattle/Cows | Milk cows that have calved |
| Replacement Heifers (0-12 mo.) | Dairy cow replacements age 0-12 months |
| Replacement Heifers (12-24 mo.) | Dairy cow replacements age 12-24 months |
| | |
| Swine | |
| Market swine <60 lbs. | Market swine in the designated weight range |
| Market swine 60-119 lbs. | Market swine in the designated weight range |
| Market swine 120-179 lbs. | Market swine in the designated weight range |
| Market swine >180 lbs. | Market swine in the designated weight range |
| Breeding swine | Swine that are breeding (non-market) |
| | |
| Poultry | |
| Hens >/= 1 yr | Female chickens that are laying eggs |
| Pullets | Young female chicken (<1 yr), category includes laying and non-laying pullets |
| Other chickens | Not otherwise categorized (e.g., roosters, mature chickens) |
| Broilers | Young chickens raised for meat production |
| Turkeys | Turkeys raised for meat production |

### Table 1.H.2. Climate regions defined by States

| Region | States in Region |
|---|---|
| California | California |
| West | Alaska, Washington, Oregon, Idaho, Nevada, Utah, Arizona, Hawaii, New Mexico |
| Northern Great Plains | Montana, Wyoming, North Dakota, South Dakota, Nebraska, Kansas, Colorado |
| South Central | Arkansas, Louisiana, Okalahoma, Texas |
| Northeast | Pennsylvania, New York, Maryland, Delaware, New Jersey, Connecticut, Rhode Island, Massachusetts, Vermont, New Hampshire, Maine, West Virginia, District of Columbia |
| Midwest | Missouri, Illinois, Indiana, Ohio, Minnesota, Wisconsin, Michigan, Iowa |
| Southeast | Virginia, North Carolina, Kentucky, Tennessee, Mississippi, Alabama, Georgia, South Carolina, Florida |

Default values are provided for broad climate regions defined by average annual mean temperature (Table 1.H.3). Data for determining an entity's climate region can be found in a number of places: Temperature data can be readily downloaded from the web site of the NRCS

National Water and Climate Center at http://www.wcc.nrcs.usda.gov. A map-based climate information retrieval system is provided at the NRCS National Water and Climate Center and can be accessed by following links for "Climate" and "Climate Reports." Entities can use county-level data on average temperatures to help establish their climate regions. County temperature data are available from a number of sources including the NOAA-Regional Climate Centers (see the NOAA web site: http://lwf.ncdc.noaa.gov/oa/climate/regionalclimatecenters.html).

### Table 1.H.3. Climate regions defined by temperature

| Region | Average mean annual temperature |
|---|---|
| Cool | <15 °C |
| Temperate | 15-25 °C |
| Warm | > 25 °C |

### 1.H.4.1.2 Enteric Fermentation

Methane ($CH_4$) is produced as a byproduct of normal animal digestion through "enteric fermentation." Enteric fermentation results from the breakdown of food by microbial populations that excrete $CH_4$, which is then emitted from the animal to the atmosphere through exhaling or eructation. Ruminant livestock (including cattle, sheep, and goats) have greater rates of enteric fermentation because of their unique digestive system, which contains a large rumen where enteric fermentation takes place. Non-ruminant livestock (such as swine, horses, and mules) produce less $CH_4$ because enteric fermentation takes place only in the large intestine. The energy content and quantity of animal feed also affect $CH_4$ emissions from enteric fermentation—lower quality and higher animal intake of feed generally lead to greater $CH_4$ emissions.

#### 1.H.4.1.2.1 Inference Using Default Emission Factors

**Rating: B**

A general estimate of the methane production by ruminants can be developed using emission factors in Table 1.H.4. The approach uses the equation below and follows these steps: First, characterize cattle populations and climate region(s) within entity boundaries using the definitions provided above under "Characterizing Animal Populations and Climate Regions." Next, multiply the population numbers for each cattle category by the appropriate emission factor in Table 1.H.4. For other, non-cattle livestock, multiply population numbers by default emission factors (non-region-specific) in Table 1.H.5. Finally, sum population emission estimates for an entity total.

$$CH_4 = \sum P_i * EF_i$$

**Where:**

**$P_i$ = population size of livestock category i**

**$EF_i$ = emission factor for livestock category i (specific to entity region for cattle categories)**

## Table 1.H.4. Methane emission factors for U.S. cattle by region (kg $CH_4$/head/year)

| Animal | California | West | Northern Great Plains | South-central | Northeast | Midwest | Southeast |
|---|---|---|---|---|---|---|---|
| Beef Cows | 73.8 | 85.3 | 71.8 | 74.6 | 74.1 | 74.1 | 74.7 |
| Beef Replacement Heifer (0-12 mo.) | 40.2 | 46.8 | 39.0 | 40.6 | 40.3 | 40.3 | 40.7 |
| Beef Replacement Heifer (12-24 mo.) | 62.9 | 73.8 | 61.0 | 63.6 | 63.1 | 63.2 | 63.7 |
| Steer Stockers | 54.1 | 63.7 | 52.5 | 54.8 | 54.4 | 54.4 | 54.9 |
| Heifer Stockers | 48.5 | 56.8 | 47.0 | 49.0 | 48.7 | 48.7 | 49.1 |
| Steer Feedlot | 33.2 | 33.5 | 33.5 | 33.6 | 33.5 | 33.7 | 33.9 |
| Heifer Feedlot | 31.3 | 31.6 | 31.6 | 31.7 | 31.6 | 31.8 | 32.0 |
| Bulls | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 | 100.0 |
| Dairy Cows | 107.2 | 137.0 | 117.4 | 108.4 | 117.2 | 115.4 | 108.4 |
| Dairy Replacement Heifer (0-12 mo.) | 40.3 | 40.3 | 38.1 | 45.5 | 40.7 | 38.1 | 46.9 |
| Dairy Replacement Heifer (12-24 mo.) | 63.3 | 63.3 | 59.9 | 71.6 | 63.9 | 59.9 | 73.7 |

Source: U.S. Environmental Protection Agency. 2005. Emission Inventory Improvement Program. Volume VIII. Chapter 7. Methods for Estimating Methane Emissions from Domesticated Animals, Table 7.4-4.

## Table 1.H.5. Methane Emission Factors for non-cattle livestock categories (kg $CH_4$/head/year)

| Livestock Category | Emission factor |
|---|---|
| Sheep | 8 |
| Goats | 5 |
| Swine | 1.5 |
| Horses | 18 |

Source: Intergovernmental Panel on Climate Change. 1997. *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*. Reference Manual (Volume 3). Chapter 4: Agriculture. Paris, France, (see Table 4.3 on page 4.10).

### 1.H.4.1.2.2 Inference Using Improved Emission Factors

**Rating: A**

Given the relative importance of enteric fermentation emissions from beef and dairy cattle, entities can improve their greenhouse gas inventories from livestock by applying specialized emission factors for cattle into the equation provided immediately above (i.e., in 1.H.4.1.2.1). Guidance is provided below on how to develop specialized emission factors for several categories of cattle based on livestock diet characteristics. For each type of cattle maintained by an entity or sub-entity, the reporter should develop an emission factor using the equation below. For all other livestock categories, the default emission factors provided in Table 1.H.5 should be used.

$$EF_i = (GE * Y_m * 365 \text{ days/yr}) / (55.65 \text{ MJ/kg } CH_4)$$

**Where:**

**$EF_i$ = emission factor for cattle category i (kilograms of methane per head per year)**

**GE = gross energy intake (MJ/head/day)**

**$Y_m$ = conversion rate of gross energy intake to methane (specific to entity region and is the fraction of GE in feed converted to methane)**

GE can be estimated from the total amount of feed given to a livestock group daily, divided by the number of animals in that group, and multiplied by the metabolizable energy (ME) content of the feed. ME values for common feed types are published by the National Research Council and are reproduced in Table 1.H.A.25 at the end of Part H.

The Environmental Protection Agency (EPA) estimates for methane conversion rates ($Y_m$) for different groups of cattle are provided in Table 1.H.6. Regions and cattle categories are defined above under "Characterizing Animal Populations and Climate Regions.

**Table 1.H.6. Methane conversion rates ($Y_m$) for cattle, by region**

| Livestock Category | California | West | Northern Great Plains | South central | Northeast | Midwest | Southeast |
|---|---|---|---|---|---|---|---|
| Beef replacement heifer | 0.065 | 0.065 | 0.065 | 0.065 | 0.065 | 0.065 | 0.065 |
| Steer Stocker | 0.065 | 0.065 | 0.065 | 0.065 | 0.065 | 0.065 | 0.065 |
| Heifer Stocker | 0.065 | 0.065 | 0.065 | 0.065 | 0.065 | 0.065 | 0.065 |
| Beef Cows | 0.065 | 0.065 | 0.065 | 0.065 | 0.065 | 0.065 | 0.065 |
| Steer Feedlot | 0.030 | 0.030 | 0.030 | 0.030 | 0.030 | 0.030 | 0.030 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Heifer Feedlot | 0.030 | 0.030 | 0.030 | 0.030 | 0.030 | 0.030 | 0.030 |
| Steer Step-up | 0.048 | 0.048 | 0.048 | 0.048 | 0.048 | 0.048 | 0.048 |
| Heifer Step-up | 0.048 | 0.048 | 0.048 | 0.048 | 0.048 | 0.048 | 0.048 |
| Diary replacement heifer | 0.059 | 0.059 | 0.056 | 0.064 | 0.063 | 0.056 | 0.069 |
| Dairy cows | 0.048 | 0.058 | 0.058 | 0.057 | 0.058 | 0.058 | 0.056 |

Source: U.S. Environmental Protection Agency. 2005. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003*. Annex 3. Table 3-83, page 177.

### 1.H.4.1.2.3 Alternative Approach for Enteric Fermentation

Entities can use measurement techniques to estimate methane emissions from grazing livestock at the herd level. This approach requires the entity to take samples from experimental animals on similar diets and with similar energy requirements.

The sulfur hexafluoride ($SF_6$) tracer technique (Johnson 2004) can be used to estimate methane emissions from selected animals and expanded to herd levels in specific locations. A small permeation tube containing $SF_6$ is introduced into the rumen and releases the inert gas at a constant rate. The $SF_6$ is captured via a vacuum tube and halter fitted for the animal. Methane and $SF_6$ concentrations in the vacuum tube are then analyzed using gas chromatography to predict the rate of methane production.

This method to predict changes in methane production is suitable for reporting greenhouse gas emission changes if a representative sample of animals are selected. At a minimum, a herd should be stratified by reproductive status (breeding females, breeding males, nonbreeding females, calves) and animal breed. The reproductive groups should be further stratified by weight and/or age if the weight of animals within a group varies by more than 25 percent of the average and/or the age of animals within a group varies by more than three years.

Because diet quality is an important determinant of methane production, sample animals must be exposed to diets that are similar to the entire herd. Sample animals should also reflect the age, breed and reproductive structure of the herd(s).

The $SF_6$ method is experimental and has been proven only within a portion of the range of conditions encountered by commercial livestock grazing. Using this technique to estimate emission reductions requires substantial knowledge of ruminant physiology, grazing animal behavior, gas chromatography and statistical analysis. Because the default enteric fermentation emission factors and $Y_m$ values provided above have been developed based on regional averages, there is uncertainty associated with them in a site-specific situation. Reducing the uncertainty of estimates based on default data can be accomplished by using locally-available research or by obtaining direct measurement of emissions from individual animals (via negative pressure sampling collars and sulfur hexafluoride tracer method) and expanding those estimates to a herd

level using statistical techniques (Johnson and Johnson 1995). The cost effectiveness of this approach can be enhanced by applying it to several similar herds in an area using a project approach.

Entities developing methods for estimating emissions from enteric fermentation based on the $SF_6$ technique must follow the guidelines for new methods provided in Chapter 1, Part A, Section A.4.

### 1.H.4.1.3 Livestock Waste

$CH_4$ and $N_2O$ emissions from waste are caused by the biological breakdown of organic matter in the waste. Livestock waste can be managed with storage and treatment systems, or spread daily on fields in lieu of long-term storage. In some cases, livestock waste is "unmanaged" and is deposited directly on pastures, ranges, or paddocks while animals graze. Table 1.H.7 provides descriptions of managed and unmanaged systems for livestock waste, indicating in general terms the impacts of different systems on GHG emissions. Livestock waste that is stored and treated is sometimes applied subsequently as a nutrient amendment to agricultural soils. Emissions from manure applications are covered below in the subsection titled "$N_2O$ from Agricultural Soils."

**Table 1.H.7. Livestock waste and GHG emissions**

| Livestock Category | Description | Relative $CH_4$ emissions | Relative $N_2O$ emissions |
|---|---|---|---|
| Pasture/range/paddock | Waste from pasture- and range-grazing animals is deposited directly onto the soil. | Low | High |
| Daily spread | Waste is collected and spread on fields. There is little or no storage of the waste before it is applied to soils. | Low | see note (1) at end of table |
| Solid storage | Waste (with or without litter) is collected by some means and placed under long-term bulk storage. | Low | High |
| Dry lot | Waste is deposited directly onto unpaved feedlots where the manure is allowed to dry and is periodically removed (after removal it is sometimes spread onto fields). | Low | High |
| Liquid/slurry | Waste is collected and transported in a liquid state to tanks for storage. The liquid/slurry mixture may be stored for a long time and water may be added to facilitate handling. | Moderate to high | Low |
| Anaerobic lagoon | Waste is collected using a flush system and transported to lagoons for storage. Waste resides in lagoons for 30-200 days. | Variable | Low |
| Pit storage | Waste is stored in pits below livestock confinements. | Moderate to high | Low |
| Poultry house with bedding | Waste is excreted on poultry house floor covered with bedding; poultry can walk on the floor. | Low | High |

| Livestock Category | Description | Relative $CH_4$ emissions | Relative $N_2O$ emissions |
|---|---|---|---|
| Poultry house without bedding | Waste is excreted on poultry house floor, which is not covered with bedding; poultry cannot walk on the floor. | Low | Low |

Source: Intergovernmental Panel on Climate Change. 2000. *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*. Chapter 4. IPCC National Greenhouse Gas Inventories Programme Technical Support Unit. Japan Tables 4.10, table 4.11, and 4.12.
(1) IPCC table 4.12 considers $N_2O$ emissions from excretion. $N_2O$ emissions from "daily spread" are considered under manure management. In the 1605b Technical Guidelines, methods for estimating $N_2O$ emissions from daily spread are described in Section 1.H.4.2.3 $N_2O$ from Agricultural Soils.

### 1.H.4.1.3.1 Inference Using Emission Factors Specific to Livestock Category and Waste Management System - Methane ($CH_4$)

**Rating: B**

Reporters should follow the same general process as for enteric fermentation: characterize the livestock populations owned by the entity; multiply the population categories by the appropriate emission factor; and sum the estimates for all population categories.

$$CH_4 = \sum P_i * EF_i$$

**Where:**

**$P_i$ = population size of livestock category i**

**$EF_i$ = $CH_4$ emission factor for livestock category i (specific to entity region for cattle categories)**

Guidance is provided below on how to develop specialized emission factors based on livestock characteristics and waste management systems for cattle, swine, and poultry. For horses, sheep, and goats, multiply population numbers by default emissions factors in Table 1.H.8, choosing the factor most appropriate for your climate region.

### Table 1.H.8. Default methane emissions factors for waste from sheep, goats, or horses (kilograms of methane per head per year)

| Livestock Category | Climate Region | | |
|---|---|---|---|
| | Cool | Temperate | Warm |
| Sheep | 0.19 | 0.28 | 0.37 |
| Goats | 0.12 | 0.18 | 0.23 |
| Horses | 1.4 | 2.1 | 2.8 |

Source: Intergovernmental Panel on Climate Change. 1997. Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories. Reference Manual (Volume 3). Chapter 4: Agriculture. Paris, France. (see Table 4.5). For cattle, swine, and poultry, further subdivide population data by system used to manage waste. For each combination of livestock type and waste management system maintained by an entity or sub-entity, develop an emission factor using the equation below and coefficients provided in Tables 1.H.9, 1.H.10, 1.H.11, and 1.H.12.

$$EF_{i,j} = VS_i \text{ (Mass)} * 365 \text{ days/yr} * Bo_i * 0.67 \text{ kg/m}^3 * MCF_{i,j}$$

**Where:**

**$EF_{i,j}$ = emissions factor for $CH_4$ from waste for livestock category i in management system j (kilograms of methane per head per year)**

**$VS_i$ = daily volatile solid excreted per 1,000 kg mass by livestock category i (kilograms of volatile solids per 1,000 kg of animal mass per day)**

**Mass = average animal mass in 1,000 kg for livestock category i (1,000 kilograms of animal mass)**

**$Bo_i$ = maximum $CH_4$ producing capacity for manure produced by an animal in category i (cubic meters of methane per kilogram of volatile solids)**

**$MCF_{i,j}$ = methane conversion factor for livestock category i in management system j**

EPA developed estimates of VS and $B_o$ for cattle, swine, and poultry categories. National-level estimates for $B_o$ by livestock category are provided in Table 1.H.9, as are national-level VS values for some livestock categories. As indicated in the table, State-level VS values for the other livestock categories can be found in Table 1.H.10. If entities have data on volatile solids excretion or can derive an estimate based on waste produced per day, those data should be used in place of State-level defaults. Entities will also need to estimate or measure directly the average animal mass for each livestock category based on entity records.

### Table 1.H.9. Volatile solids (VS) and maximum methane producing capacity (Bo) values for cattle, swine, and poultry

| Livestock | Max Methane Generation Potential, Bo | Volatile Solids VS |
|---|---|---|
| | $m^3$ $CH_4$/kg VS added | kg/day per 1,000 kg mass |
| Dairy cow | 0.24 | see Table 1.H.10 |
| Dairy heifer | 0.17 | see Table 1.H.10 |
| Feedlot steers | 0.33 | see Table 1.H.10 |
| Feedlot heifers | 0.33 | see Table 1.H.10 |
| Not on feed, bulls | 0.17 | 6.04 |
| Not on feed, calves | 0.17 | 6.41 |
| Not on feed, heifers | 0.17 | see Table 1.H.10 |
| Not on feed, steers | 0.17 | see Table 1.H.10 |
| NOF cows | 0.17 | see Table 1.H.10 |
| Market swine <60 lbs. | 0.48 | 8.8 |
| Market swine 60-119 lbs. | 0.48 | 5.4 |
| Market swine 120-179 lbs. | 0.48 | 5.4 |
| Market swine >180 lbs. | 0.48 | 5.4 |

| | | |
|---|---|---|
| Breeding swine | 0.48 | 2.6 |
| Hens >/= 1 yr | 0.39 | 10.8 |
| Pullets | 0.39 | 9.7 |
| Other chickens | 0.39 | 10.8 |
| Broilers | 0.36 | 15 |
| Turkeys | 0.36 | 9.7 |

Source: Environmental Protection Agency. 2005. Emission Inventory Improvement Program. Volume VIII. Chapter 8. Methods for Estimating Greenhouse Gas Emissions from Livestock Manure Management, Table 8.4-2.

## Table 1.H.10. Volatile solids ($VS_i$) by State for cattle groups (kg/day per 1,000 kg mass)

| State | Dairy Cow | Dairy Heifer | Cows, not on feed | Heifers, not on feed | Steers, not on feed | Feedlot Heifers | Feedlot Steers |
|---|---|---|---|---|---|---|---|
| Alabama | 8.50 | 6.82 | 6.74 | 7.22 | 7.72 | 4.06 | 3.89 |
| Alaska | 10.87 | 6.82 | 8.71 | 9.50 | 10.21 | 4.03 | 3.87 |
| Arizona | 10.87 | 6.82 | 8.71 | 9.53 | 10.21 | 4.03 | 3.87 |
| Arkansas | 8.58 | 7.57 | 6.72 | 7.20 | 7.70 | 4.03 | 3.87 |
| California | 9.38 | 6.82 | 6.57 | 7.06 | 7.51 | 3.96 | 3.80 |
| Colorado | 8.68 | 6.82 | 6.19 | 6.67 | 7.04 | 4.03 | 3.87 |
| Connecticut | 8.44 | 6.14 | 6.62 | 7.13 | 7.58 | 4.01 | 3.84 |
| Delaware | 8.44 | 6.14 | 6.62 | 7.14 | 7.58 | 4.01 | 3.84 |
| Florida | 8.50 | 6.82 | 6.74 | 7.20 | 7.72 | 4.06 | 3.89 |
| Georgia | 8.50 | 6.82 | 6.74 | 7.22 | 7.72 | 4.06 | 3.89 |
| Hawaii | 10.87 | 6.82 | 8.71 | 9.52 | 10.21 | 4.03 | 3.87 |
| Idaho | 10.87 | 6.82 | 8.71 | 9.59 | 10.21 | 4.03 | 3.87 |
| Illinois | 8.54 | 6.82 | 6.63 | 7.15 | 7.58 | 3.96 | 3.80 |
| Indiana | 8.54 | 6.82 | 6.63 | 7.13 | 7.58 | 3.96 | 3.80 |
| Iowa | 8.54 | 6.82 | 6.63 | 7.17 | 7.58 | 3.96 | 3.80 |
| Kansas | 8.68 | 6.82 | 6.19 | 6.67 | 7.04 | 4.03 | 3.86 |
| Kentucky | 8.50 | 6.82 | 6.74 | 7.24 | 7.72 | 4.06 | 3.89 |
| Louisiana | 8.58 | 7.57 | 6.72 | 7.08 | 7.70 | 4.03 | 3.87 |
| Maine | 8.44 | 6.14 | 6.62 | 7.18 | 7.58 | 4.01 | 3.84 |
| Maryland | 8.44 | 6.14 | 6.62 | 7.11 | 7.58 | 4.01 | 3.84 |
| Massachusetts | 8.44 | 6.14 | 6.62 | 7.12 | 7.58 | 4.01 | 3.84 |
| Michigan | 8.54 | 6.82 | 6.63 | 7.13 | 7.58 | 3.96 | 3.80 |
| Minnesota | 8.54 | 6.82 | 6.63 | 7.14 | 7.58 | 3.96 | 3.80 |
| Mississippi | 8.50 | 6.82 | 6.74 | 7.21 | 7.72 | 4.06 | 3.89 |
| Missouri | 8.54 | 6.82 | 6.63 | 7.12 | 7.58 | 3.96 | 3.80 |
| Montana | 8.68 | 6.82 | 6.19 | 6.60 | 7.04 | 4.03 | 3.86 |
| Nebraska | 8.68 | 6.82 | 6.19 | 6.67 | 7.04 | 4.03 | 3.86 |
| Nevada | 10.87 | 6.82 | 8.71 | 9.54 | 10.21 | 4.03 | 3.87 |
| New Hampshire | 8.44 | 6.14 | 6.62 | 7.08 | 7.58 | 4.01 | 3.84 |
| New Jersey | 8.44 | 6.14 | 6.62 | 7.11 | 7.58 | 4.01 | 3.84 |
| New Mexico | 10.87 | 6.82 | 8.71 | 9.56 | 10.21 | 4.03 | 3.87 |
| New York | 8.44 | 6.14 | 6.62 | 7.14 | 7.58 | 4.01 | 3.84 |

| State | Dairy Cow | Dairy Heifer | Cows, not on feed | Heifers, not on feed | Steers, not on feed | Feedlot Heifers | Feedlot Steers |
|---|---|---|---|---|---|---|---|
| North Carolina | 8.50 | 6.82 | 6.74 | 7.21 | 7.72 | 4.06 | 3.89 |
| North Dakota | 8.68 | 6.82 | 6.19 | 6.64 | 7.04 | 4.03 | 3.86 |
| Ohio | 8.54 | 6.82 | 6.63 | 7.12 | 7.58 | 3.96 | 3.80 |
| Oklahoma | 8.58 | 7.57 | 6.72 | 7.24 | 7.70 | 4.03 | 3.87 |
| Oregon | 10.87 | 6.82 | 8.71 | 9.55 | 10.21 | 4.03 | 3.87 |
| Pennsylvania | 8.44 | 6.14 | 6.62 | 7.12 | 7.58 | 4.01 | 3.84 |
| Rhode Island | 8.44 | 6.14 | 6.62 | 7.08 | 7.58 | 4.01 | 3.84 |
| South Carolina | 8.50 | 6.82 | 6.74 | 7.22 | 7.72 | 4.06 | 3.89 |
| South Dakota | 8.68 | 6.82 | 6.19 | 6.64 | 7.04 | 4.03 | 3.86 |
| Tennessee | 8.50 | 6.82 | 6.74 | 7.22 | 7.72 | 4.06 | 3.89 |
| Texas | 8.58 | 7.57 | 6.72 | 7.25 | 7.70 | 4.03 | 3.87 |
| Utah | 10.87 | 6.82 | 8.71 | 9.55 | 10.21 | 4.03 | 3.87 |
| Vermont | 8.44 | 6.14 | 6.62 | 7.12 | 7.58 | 4.01 | 3.84 |
| Virginia | 8.50 | 6.82 | 6.74 | 7.23 | 7.72 | 4.06 | 3.89 |
| Washington | 10.87 | 6.82 | 8.71 | 9.59 | 10.21 | 4.03 | 3.87 |
| West Virginia | 8.44 | 6.14 | 6.62 | 7.10 | 7.58 | 4.01 | 3.84 |
| Wisconsin | 8.54 | 6.82 | 6.63 | 7.12 | 7.58 | 3.96 | 3.80 |
| Wyoming | 8.68 | 6.82 | 6.19 | 6.63 | 7.04 | 4.03 | 3.86 |

Source: Environmental Protection Agency. 2005. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003*. Annex 3. Table 3-90, page 189.

State-level default methane conversion factors (MCF) for pasture, range and paddock, dry lot systems, and liquid systems (i.e., anaerobic lagoons) are provided in Table 1.H.11. Default emission factors developed by the Intergovernmental Panel on Climate Change (IPCC) and categorized by broad climate region for all other common management systems are in Table 1.H.12.

### Table 1.H.11. State-level methane conversion factors (MCF) for Pasture, Range and Paddocks, Drylots, and Liquid Systems

| State | Range & Paddocks [1] | Drylot [1] | Liquid/Slurry & Deep Pit | Anaerobic Lagoon |
|---|---|---|---|---|
| Alabama | 0.014 | 0.019 | 0.385 | 0.758 |
| Alaska | NA | NA | 0.138 | 0.483 |
| Arizona | 0.014 | 0.019 | 0.448 | 0.793 |
| Arkansas | 0.013 | 0.018 | 0.361 | 0.65 |
| California | 0.012 | 0.014 | 0.377 | 0.762 |
| Colorado | 0.009 | 0.01 | 0.222 | 0.667 |
| Connecticut | 0.009 | 0.01 | 0.239 | 0.694 |
| Delaware | 0.012 | 0.014 | 0.297 | 0.739 |
| Florida | 0.015 | 0.024 | 0.552 | 0.778 |

| | | | | |
|---|---|---|---|---|
| Georgia | 0.014 | 0.018 | 0.383 | 0.756 |
| Hawaii | NA | NA | 0.597 | 0.771 |
| Idaho | 0.008 | 0.008 | 0.232 | 0.683 |
| Illinois | 0.011 | 0.013 | 0.269 | 0.715 |
| Indiana | 0.01 | 0.012 | 0.260 | 0.706 |
| Iowa | 0.009 | 0.011 | 0.247 | 0.697 |
| Kansas | 0.011 | 0.015 | 0.319 | 0.745 |
| Kentucky | 0.012 | 0.015 | 0.304 | 0.732 |
| Louisiana | 0.014 | 0.021 | 0.461 | 0.772 |
| Maine | 0.008 | 0.008 | 0.195 | 0.633 |
| Maryland | 0.011 | 0.012 | 0.276 | 0.721 |
| Massachusetts | 0.009 | 0.01 | 0.232 | 0.687 |
| Michigan | 0.008 | 0.009 | 0.220 | 0.667 |
| Minnesota | 0.008 | 0.008 | 0.228 | 0.679 |
| Mississippi | 0.014 | 0.019 | 0.401 | 0.761 |
| Missouri | 0.011 | 0.014 | 0.304 | 0.738 |
| Montana | 0.007 | 0.008 | 0.211 | 0.659 |
| Nebraska | 0.01 | 0.011 | 0.267 | 0.715 |
| Nevada | 0.012 | 0.014 | 0.257 | 0.705 |
| New Hampshire | 0.008 | 0.008 | 0.210 | 0.655 |
| New Jersey | 0.01 | 0.011 | 0.264 | 0.719 |
| New Mexico | 0.012 | 0.013 | 0.326 | 0.744 |
| New York | 0.009 | 0.009 | 0.217 | 0.666 |
| North Carolina | 0.013 | 0.015 | 0.337 | 0.744 |
| North Dakota | 0.007 | 0.007 | 0.217 | 0.669 |
| Ohio | 0.01 | 0.011 | 0.248 | 0.695 |
| Oklahoma | 0.014 | 0.019 | 0.365 | 0.761 |
| Oregon | 0.011 | 0.011 | 0.228 | 0.670 |
| Pennsylvania | 0.009 | 0.01 | 0.252 | 0.704 |
| Rhode Island | 0.01 | 0.011 | 0.246 | 0.704 |
| South Carolina | 0.013 | 0.017 | 0.378 | 0.758 |
| South Dakota | 0.008 | 0.009 | 0.242 | 0.696 |
| Tennessee | 0.013 | 0.016 | 0.326 | 0.742 |
| Texas | 0.014 | 0.021 | 0.416 | 0.770 |
| Utah | 0.009 | 0.01 | 0.262 | 0.771 |
| Vermont | 0.008 | 0.008 | 0.202 | 0.645 |
| Virginia | 0.012 | 0.014 | 0.279 | 0.720 |
| Washington | 0.01 | 0.01 | 0.233 | 0.679 |

| | | | | |
|---|---|---|---|---|
| West Virginia | 0.012 | 0.013 | 0.253 | 0.698 |
| Wisconsin | 0.008 | 0.008 | 0.224 | 0.677 |
| Wyoming | 0.008 | 0.008 | 0.213 | 0.660 |

NA = not available

Sources:

1. Environmental Protection Agency. 2005. Emission Inventory Improvement Program. Volume VIII. Chapter 8. Methods for Estimating Greenhouse Gas Emissions from Livestock Manure Management. See Table 8.4-12.
2. Environmental Protection Agency. 2005. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003*. Annex 3. Table 3-97.

### Table 1.H.12. Methane conversion factors (MCF) for select management systems (ratio of actual to maximum possible methane production)

| System | Cool | Temperate | Warm |
|---|---|---|---|
| Daily spread | 0.001 | 0.005 | 0.01 |
| Solid storage | 0.01 | 0.015 | 0.02 |
| Pit storage | | | |
| Short term (< 1 month) | 0 | 0 | 0.3 |
| Long term (>1 month) | 0.39 | 0.45 | 0.72 |
| Poultry house with bedding | 0.015 | 0.015 | 0.015 |
| Poultry house without bedding | 0.015 | 0.015 | 0.015 |

Source: Intergovernmental Panel on Climate Change. 2000. *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*. Chapter 4. IPCC National Greenhouse Gas Inventories Programme Technical Support Unit. Japan Table 4.10, pp. 4.35-4.36.

### 1.H.4.1.3.2 Inference Using Emission Factors Specific to Livestock Category and Waste Management System – Nitrous Oxide ($N_2O$)

**Rating: B**

Reporters should divide livestock populations into the management system categories shown in Table 1.H.13, and then multiply each livestock population by the appropriate $N_2O$ emissions factor also shown in Table 1.H.13. Emission factors are based on default data published by the IPCC.

### Table 1.H.13. $N_2O$ emission factors for livestock by waste management system in the United States (kilograms of nitrous oxide per head per year)

| Livestock Category | Anaerobic Lagoon | Liquid System | Solid storage and drylot | Pasture, range grazing systems |
|---|---|---|---|---|
| Non-Dairy Cattle | 0.11 | 0.11 | 2.20 | 2.20 |
| Dairy/Feedlot Cattle | 0.16 | 0.16 | 3.14 | 3.14 |
| Poultry | 0.0009 | 0.0009 | 0.02 | 0.02 |
| Sheep | 0.03 | 0.03 | 0.50 | 0.50 |
| Swine | 0.03 | 0.03 | 0.63 | 0.63 |

Source: Intergovernmental Panel on Climate Change. 1997. *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*. Reference Manual (Volume 3). Chapter 4: Agriculture. Paris, France, Tables 4-20 and Table 4-22.

Because the factors driving methane production from livestock waste are somewhat responsive to site-specific conditions (diet quality, temperature, precipitation, variations in method of handling, etc.) the estimation methods described here are uncertain when applied to a specific situation.

#### 1.H.4.1.3.3 Additional Resources

Anaerobic digesters are components of waste treatment systems that promote the production and capture of methane gas, which can then be used to produce energy. There are numerous designs for anaerobic digesters that generally consist of an airtight cover over a waste impoundment.

**Box 1.H.1: Guidance on Estimating Greenhouse Gas Emission Reductions from Anaerobic Digesters**

Managing livestock waste with anaerobic digesters can result in three types of greenhouse gas emission reductions: direct reductions from capturing methane produced from decomposing livestock waste that otherwise would have been emitted, indirect emission reductions of $CO_2$ related to reduced on-farm use of purchased energy, and avoided emissions of $CO_2$ related to exporting green energy to off-farm users. The type and quantity of emission reductions an entity may report depends upon when the digester is installed and on how the captured methane is disposed of or utilized.

To register reductions related to the direct capture of methane emissions, entities must install the digester after the base period. For purposes of calculating reductions, average total annual methane flows captured and flared or sold for energy in the base period should be reported as the base value. If the animal waste was handled as a solid, or deposited on pasture, range, or paddock lands to decompose aerobically during the base period, no reductions of methane may be reported. If animal waste was handled under anaerobic conditions and no gas was captured and flared or sold for energy recovery during the base period, the base-value quantity should be zero.

Irrespective of the installation date, entities may register reductions in $CO_2$ emissions if the captured methane is used to generate energy that either decreases farm-use of purchased energy (i.e., reduces indirect emissions), or, is exported off-farm as green energy (i.e., increases avoided emissions). Guidelines, methods, and default coefficients for calculating changes in indirect emissions are contained in Chapter 1, Part F of the Technical Guidelines. Guidelines, methods, and default coefficients for calculating changes in avoided emissions are contained in Chapter 2.4.3 of the Technical Guidelines.

If the recovered methane is added to a natural gas supply network or sold directly for use as a fuel, any changes in emissions will be captured by the consumer and should be treated as having no net effect of emissions reported for this specific action.

Additional guidance and a list of required documentation for registering emission reductions from the capture of methane from the anaerobic digestion of animal waste are contained in Chapter 2.4.5 of the Technical Guidelines.

An introduction to anaerobic digester technologies and guidance on the selection, implementation, and management of technologies to capture methane emissions from livestock wastes is in the EPA publication, *AgStar Biogas Handbook* (available at the web site: http://www.epa.gov/agstar/resources/handbook.html).

The EPA FarmWare software can be used to estimate methane production from waste management; methodologies and measurement tools are described in Appendix C of the *AgStar Biogas Handbook.*

Guidance on designing and implementing agricultural management practices is provided by USDA NRCS in the "National Conservation Practice Standards." The complete set of "National Conservation Practice Standards" can be found at web site: www.nrcs.usda.gov/Technical/Standards/index.html.

Practices to reduce emissions from livestock wastes should be consistent with practice standards and specifications for the following (each standard is identified by a unique number shown in parentheses): Manure Transfer (634), Composting Facility (317), and Nutrient Management (590).

## 1.H.4.2 Crop Production Sources

### 1.H.4.2.1 Residue Burning

Burning crop residues and native vegetation is not considered to be a significant source of carbon dioxide released in the United States. Carbon dioxide released during burning is generally taken up by vegetation the following growing season and is not considered a source of anthropogenic carbon dioxide emissions. Field burning of crop residues emits nitrous oxide and methane to the atmosphere. Methods below can be used to estimate nitrous oxide and methane emissions from residue burning. The methods are based on national averages combined with site-specific information on crop production and burning activity.

#### 1.H.4.2.1.1 Inference Using Default Emission Factors – Nitrous Oxide ($N_2O$)

**Rating: B**

Nitrous oxide emissions from residue burning can be estimated based on the amount of crops produced and the fraction burned annually (IPCC 1997). In addition, data are needed on the ratio of residue to crop product, dry matter content of residue, burning efficiency, nitrogen content, and combustion efficiency. National defaults for these data were developed by the EPA and are provided in Table 1.H.14 (EPA 2003). Finally, an $N_2O$ emission factor is used to convert the amount of nitrogen released to nitrous oxide emissions.

**Table 1.H.14. Default data for estimating $N_2O$ and $CH_4$ emissions from burning of crop residues**

| | Corn | Peanuts | Soybeans | Barley | Wheat | Rice | Sugarcane |
|---|---|---|---|---|---|---|---|
| Ratio residue:crop | 1 | 1 | 2.1 | 1.2 | 1.3 | 1.4 | 0.8 |
| DM (Dry Matter Content of Residues) | 0.91 | 0.86 | 0.87 | 0.93 | 0.93 | 0.91 | 0.62 |
| BE (Burning Efficiency) | 0.93 | 0.93 | 0.93 | 0.93 | 0.93 | 0.93 | 0.93 |
| CE (Combustion Efficiency) | 0.88 | 0.88 | 0.88 | 0.88 | 0.88 | 0.88 | 0.88 |
| C-Content (Carbon Content) | 0.4478 | 0.45 | 0.45 | 0.4485 | 0.4428 | 0.3806 | 0.4235 |
| N-Content (Nitrogen Content) | 0.0058 | 0.0106 | 0.023 | 0.0077 | 0.0062 | 0.0072 | 0.004 |

Source: Environmental Protection Agency. 2003. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001. Chapter 5 (Table 5-20 and page 5-23)

For each of the following crops, estimate the amount produced and the fraction burned at least once during the year: corn, peanuts, soybeans, barley, wheat, rice, sugarcane. Use the default data in Table 1.H.14 to complete the equation below for each crop type. Sum the emissions from each crop type for a total amount of $N_2O$ emissions from residue burning.

$$N_2O = Prod \times Frac_{burned} \times Ratio_{residue:crop} \times DM \times BE \times CE \times N\text{-}Content \times EF_{N2O}$$

**Where**

| | | |
|---|---|---|
| **Prod** | **=** | **Annual production for a given crop type (metric tons)** |
| **$Frac_{burned}$** | **=** | **Fraction burned annually for a given crop type** |
| **$Ratio_{residue:crop}$** | **=** | **Ratio of residue to crop product volume** |
| **DM** | **=** | **Dry Matter content of residues** |
| **BE** | **=** | **Burning Efficiency (fraction of dry biomass exposed to fire that actually burns)** |
| **CE** | **=** | **Combustion Efficiency (fraction of carbon in the fire that is oxidized completely to $CO_2$)** |
| **N-Content** | **=** | **Fraction of nitrogen in biomass** |
| **$EF_{N2O}$** | **=** | **0.007 (ton $N_2O$ per ton nitrogen)** |

#### 1.H.4.2.1.1 Inference Using Default Emission Factors – Methane ($CH_4$)

**Rating: B**

Methane emissions from residue burning are estimated based on the amount of crops produced, the fraction burned annually, and default data provided in Table 1.H.14.

Use the same estimates for amount produced and fraction burned from the nitrous oxide calculations (see 1.H.4.2.1 above). Calculate emissions separately for corn, peanuts, soybeans, barley, wheat, rice, sugarcane using the default data in Table 1.H.14 to complete the equation below. Sum the emissions from each crop type for a total amount of $CH_4$ from residue burning.

$$CH_4 = Prod \times Frac_{burned} \times Ratio_{residue:crop} \times DM \times BE \times CE \times C\text{-}Content \times EF_{CH4}$$

**Where:**

| | | |
|---|---|---|
| **Prod** | **=** | **Annual production for a given crop type (metric tons)** |
| **$Frac_{burned}$** | **=** | **Fraction burned annually for a given crop type** |
| **$Ratio_{residue:crop}$** | **=** | **Ratio of residue to crop product volume** |
| **DM** | **=** | **Dry Matter content of residues** |
| **BE** | **=** | **Burning Efficiency (fraction of dry biomass exposed to fire that actually burns)** |
| **CE** | **=** | **Combustion Efficiency (fraction of carbon in the fire that is oxidized completely to $CO_2$)** |
| **C-Content** | **=** | **Faction of carbon in biomass** |
| **$EF_{CH4}$** | **=** | **0.005 (ton CH4 per ton carbon)** |

### 1.H.4.2.2 Rice Cultivation

Most rice grown in the United States is cultivated on shallow, continuously flooded fields (EPA 2003), which results in emissions of $CH_4$. Anaerobic conditions in these waterlogged soils lead to the decomposition of organic matter by $CH_4$-emitting "methanogenic" bacteria (IPCC 1997). $CH_4$ from rice fields reaches the atmosphere either by bubbling up through the soil, diffusion through water to the surface, or diffusion through the vascular elements of plants. Soil composition, texture, and temperature are important variables affecting $CH_4$ emissions from rice cultivation, as are the availability of carbon substrate and other nutrients, soil pH, and partial pressure of $CH_4$.

$CH_4$ emissions from rice cultivation are limited to eight U.S. states: Arkansas, California, Florida, Louisiana, Mississippi, Missouri, Oklahoma, and Texas. In four of those states

(Arkansas, Florida, Louisiana, and Texas), the climate allows for cultivation of two rice crops per season, the second of which is called a "ratoon crop." $CH_4$ emissions from primary and ratoon crops should be estimated separately because emissions are higher from ratoon crops (EPA 2003). The methodology described in the next subsection does not apply to rice grown on uplands that are not continuously flooded.

### 1.H.4.2.2.1 Inference Using Default Emission Factors

**Rating: B**

Methane emissions from rice can be estimated by multiplying the area of land in rice cultivation by default emission factors. Two emission factors (provided in Table 1.H.15) are needed, one for primary crops and one for ratoon crops. This methodology provides only a rough estimate of absolute emissions from rice production because it is based primarily on area of land cultivated and does not capture the impacts of land management practices. There is currently no methodology available to assess the impacts of specific management practices on $CH_4$ emissions from rice, therefore this basic methodology is provided for reporters wishing to establish emissions from this source category.

$$CH_4 = \sum Ai * EFi$$

**Where:**

**Ai = area of rice cultivation for either primary or ratoon crops (hectares)**

**EFi = emission factor for primary or ratoon crops (kilograms $CH_4$ per hectare)**

**("i" indexes primary or ratoon crop)**

## Table 1.H.15. Default emission factors for methane emissions from rice cultivation

| System | Annual emission factor (kg $CH_4$/ha) |
|---|---|
| Primary | 210 |
| Ratoon | 780 |

Source: Environmental Protection Agency. 2003. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001. Chapter 5 (page 5-14).

### 1.H.4.2.2.2 Guidance on Improving Emission Factors

The method to estimate methane emissions from rice farming contains no site specific information and is highly uncertain, but is the currently the best method available. Emissions estimates could be improved if reporters developed site-specific emission factors. Site-specific factors should be based on direct measurement or published research studies on similar rice cultivation systems, and take into consideration one or more of the following: regional rice cultivation practices; variation in growing conditions over the course of a year; water management regime and irrigation systems; application of organic amendments such as manure,

rice residue, and aquatic biomass; and soil type (IPCC 2000).

Entities using other methods for estimating emissions from rice cultivation must follow the guidelines for new methods provided in Chapter 1, Part A, Section A.4.

### 1.H.4.2.3 $N_2O$ from Agricultural Soils

Amendments that add nitrogen to soils increase the production of $N_2O$ because they provide additional nitrogen to the natural cycle of nitrification and denitrification in soils. In nitrification, soil microorganisms ("microbes") convert ammonium to nitrate through aerobic oxidation (IPCC 1997). In denitrification, microbes convert nitrate to dinitrogen gas by anaerobic reduction. During nitrification and denitrification, soil microbes release $N_2O$, which eventually reaches the atmosphere. Commercial fertilizer, livestock manure, sewage sludge, incorporation of crop residues, and cultivation of nitrogen-fixing crops— all add nitrogen to soils. Cultivating highly organic soils also enhances mineralization of nitrogen-rich organic matter, making more nitrogen available for nitrification and denitrification (EPA 2003). While $N_2O$ emissions in cultivated organic soils are not a result of nutrient applications *per se*, they are included in this category because the estimation techniques are inherently similar to those used for the various nitrogen sources described above.

In addition to the direct emissions of $N_2O$ from soil nitrification and denitrification, nitrogen may also be transported through groundwater and run-off to other systems where it is later converted to $N_2O$, causing indirect emissions of $N_2O$ (IPCC 1997). Furthermore, some applied nitrogen is volatilized into the atmosphere and subsequently deposited back onto land, causing another indirect source of $N_2O$. Indirect emissions result from the application of commercial fertilizers and livestock manure to soils.

#### 1.H.4.2.3.1. Inference Using Specific Activity Data and Default $N_2O$ Emission Factor

**Rating: B**

Emissions of $N_2O$ from agricultural soils originate from two sources: nitrogen applications and cultivation of organic soils. Methods for estimating emissions from those sources are provided below. Emissions estimates for nitrogen applications and cultivation of organic soils should be summed for a single estimate of $N_2O$ emissions from agricultural soils.

<u>1.H.4.2.3.1.1 Emissions from Nitrogen Application and Fixation</u>

Nitrogen application can originate from several sources, including commercial fertilizers, livestock manure, nitrogen fixation, and crop residues. The first step in this method is to estimate the amount of nitrogen applied to crops from each of these sources. Subsections below provide guidelines for estimating the amount of nitrogen applied by each source, which is used to estimate the amount of $N_2O$ emissions. Direct emissions of $N_2O$ occur from all sources of nitrogen discussed, while commercial fertilizers and manure applications also cause indirect emissions.

Direct emissions from nitrogen application can be estimated by multiplying a fraction of the total amount of nitrogen applied by a fixed value of 2 percent.[172] The fraction ($fraction_{direct}$) reduces the total amount of nitrogen applied to account for the portion assumed lost through indirect emissions. Fractions by nitrogen source are given in Table 1.H.16. Because there are only direct emissions from nitrogen fixing crops and crop residues, the fraction for those sources of nitrogen is 1.0.

**Direct $N_2O$ emissions (kg $N_2O$) = N applied or fixed (kg N) * $fraction_{direct}$ * 0.02 kg $N_2O$ /kg N**

Two types of indirect emissions are calculated separately for commercial fertilizer and manure, as shown in the equations below. Volatilization emissions of $N_2O$ are estimated by multiplying total nitrogen applied by a fraction to obtain the portion volatilized ($fraction_{volatilized}$), and then by a fixed value of 1.6 percent.[173] Run-off and leaching emissions of $N_2O$ are estimated by multiplying the amount of total nitrogen applied by a fraction to obtain the portion that runs off and/or leaches into ground water ($fraction_{runoff}$), and then by a fixed value of 4 percent.[174] Fractions by nitrogen source are given in Table 1.H.16.

**Volatilization $N_2O$ (kg $N_2O$) = N applied (kg N) * $fraction_{volatilized}$ * 0.016 kg $N_2O$ /kg N Run-off/leaching $N_2O$ (kg $N_2O$) = N applied (kg N) * $fraction_{runoff}$ * 0.04 kg $N_2O$ /kg N**

## Table 1.H.16. Fractions by nitrogen source

| | $fraction_{direct}$ | $fraction_{volatilized}$ | $fraction_{runoff}$ |
|---|---|---|---|
| Nitrogen fixing crops and crop residues | 1.0 | 0.0 | 0.0 |
| Synthetic commercial fertilizers | 0.9 | 0.1 | 0.3 |
| Organic commercial fertilizers and manure | 0.8 | 0.2 | 0.3 |

Source: Intergovernmental Panel on Climate Change. 1997. *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories.* Reference Manual (Volume 3). Chapter 4: Agriculture. Paris, France (table 4-24 and page 4.89).

1.H.4.2.3.1.1.1 Estimating the Amount of Nitrogen in Crop Applications

1.H.4.2.3.1.1.1.1 *Commercial Fertilizer* Reporters should determine the amount of fertilizer applied to crops, in kilograms (kg), and multiply that amount by the fertilizer's nitrogen content (given as a percent of nitrogen in product information) to determine the N applied (kg N). This should be done separately for synthetic and non-manure organic fertilizers.

1.H.4.2.3.1.1.1.2 *Livestock Manure* Determine the amount of livestock waste (manure and urine) applied to fields from different livestock types (generally this will be categorized as pounds (lbs.)

[172] The percentage reported by IPCC 1997 is 1.25 percent, expressed as nitrogen (i.e., $N_2O$-N); the factor of 2 percent converts to units of $N_2O$ using the molecular formula for $N_2O$ (e.g., multiplies 1.25 percent by 44/28).
[173] The percentage reported by IPCC 1997 is 1.0 percent, expressed as nitrogen (i.e., $N_2O$-N); the factor of 1.6 percent results from conversion to units of $N_2O$ using the molecular formula for $N_2O$ (e.g., multiplies 1.0 percent by 44/28).
[174] The percentage reported by IPCC 1997 is 2.5 percent, expressed as nitrogen (i.e., $N_2O$-N); the factor of 4 percent results from conversion to units of $N_2O$ using the molecular formula for $N_2O$ (e.g., multiplies 1.0 percent by 44/28).

of waste applied on a wet basis). Multiply the amount applied by the appropriate percent nitrogen given in Table 1.H.17. Percent nitrogen values in Table 1.H.17 are based on the percent of nitrogen in waste relative to the total wet weight of waste, as excreted (USDA 1996a). Convert "lbs" of nitrogen to "kg" before using the equations above.

### Table 1.H.17. Nitrogen content of manure for broad livestock classes

| Livestock manure | Percent N[1] |
|---|---|
| Dairy | 0.5% |
| Beef | 0.5% |
| Swine | 0.7% |
| Poultry | 2.5% |
| Sheep | 1.1% |
| Horse | 0.6% |

Source: United States Department of Agriculture. 1996. *Agricultural Waste Management Field Handbook.* Chapter 4. (Tables 4-5, 4-8, 4-11, 4-14, 4-18, and 4-19), web site: www.wcc.nrcs.usda.gov/awm/awmfh.html.
1. In the above tables, divide value for "N" by value for "Weight". For some species, values in table 1.H.17 reflect an average percent of nitrogen computed over several livestock groups.

1.H.4.2.3.1.1.1.3 *Nitrogen Fixation* For each leguminous crop type listed in Table 1.H.18, determine the annual amount of crop produced and use the equation below and corresponding coefficients in Table 1.H.18 to estimate kg N for use in the Direct $N_2O$ emissions calculation in subsection 1.H.4.2.3.1.1.

$$\text{kg N} = \text{Prod} * N_{conversion}$$

**Where:**

**Prod** = **amount of crop produced/harvested (kg)**

**$N_{conversion}$** = **fraction of nitrogen in harvest and residue biomass per kg of crop harvested**

### Table 1.H.18. Default nitrogen conversion factors for leguminous crops

| Crop | $N_{conversion}$ (kg N / kg harvested) |
|---|---|
| Soybeans | 0.062 |
| Peanuts | 0.018 |
| Dry edible beans | 0.014 |
| Dry edible peas | 0.014 |
| Austrian winter peas | 0.014 |
| Lentils | 0.014 |
| Wrinkled seed peas | 0.014 |
| Alfalfa | 0.062 |
| Forage species (other than alfalfa) | 0.067 |

Source: Environmental Protection Agency. 2003. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001.* Annex N. Table N-6.

1.H.4.2.3.1.1.1.4 *Crop Residue* The method for estimating the amount of nitrogen in crop residues is essentially the same as for estimating the amount of nitrogen in legumes, with one exception: only the nitrogen in the residue fraction of plant biomass is estimated. Use the coefficients provided in Table 1.H.19 to estimate the amount of nitrogen in crop residues.

$$\text{kg N} = \text{Prod} * N_{conversion}$$

**Where:**

**Prod** = **amount of crop produced/harvested (kg)**

**$N_{conversion}$** = **fraction of nitrogen in residue biomass per kg of crop harvested**

### Table 1.H.19. Default ratios for nitrogen content for major crops

| Crop | $N_{conversion}$ (kg N / kg harvested) |
|---|---|
| Corn | 0.005 |
| Wheat | 0.007 |
| Barley | 0.009 |
| Sorghum | 0.014 |
| Oats | 0.008 |
| Rye | 0.007 |
| Millet | 0.009 |
| Rice | 0.009 |

Environmental Protection Agency. 2003. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001*. Annex N, Table N-6.

1.H.4.2.3.1.2 Emissions from Cultivation of Organic Soils

Standard soil taxonomy classifies organic soils as "histosols."[175] To estimate annual $N_2O$ emissions from cultivated organic soils, estimate the area of organic soils cultivated within the entity and determine whether the entity is in a temperate or subtropical climate region. Note that most of the United States is considered temperate, except for parts of the Gulf coast. See Map 1.H.1 below in the subsection titled "Characterizing the Land Base." Multiply the area by the appropriate emissions factor in Table 1.H.20.

$$N_2O = \sum A_i * EF_i$$

[175] Histosols are "Organic soils that have organic soil materials in more than half of the upper 80 cm, or that area of any thickness of overlying rock or fragmented materials that have interstices filled with organic soil materials." An organic soil material is defined as: "soil materials that are saturated with water and have 174 g/kg or more organic carbon if the mineral fraction has 500 g/kg or more clay, or 116 g/kg organic carbon if the mineral fraction has no clay, or has proportional intermediate contents, or if never saturated with water, have 203 g/kg or more organic carbon." (SSSA 2001).

**Where:**

**$A_i$ = area of organic soils cultivated in climate region i (ha)**

**$EF_i$ = emission factor climate region i (kg $N_2O$/ha)**

## Table 1.H.20. Emission factors for $N_2O$ from organic soil cultivation

| Region | Emission factor (kg $N_2O$/ha) |
|---|---|
| Temperate | 12.57 |
| Subtropical | 18.86 |

Sources:
1. Environmental Protection Agency. 2003. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001*. Chapter 5. pg. 5-17.
2. Intergovernmental Panel on Climate Change. 2000. *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories.* Chapter 4. IPCC National Greenhouse Gas Inventories Programme Technical Support Unit. Japan Table 4.17, pp. 4.60. Values in Table 4.17 are in units of, $N_2O$-N. To convert to units of $N_2O$ use the formula: $N_2O = N_2O\text{-}N * 44/28$

Emissions of nitrous oxide from agricultural soils, both direct and indirect, are greatly affected by site-specific factors such as soil texture, soil moisture, precipitation and atmospheric conditions. Thus, estimates obtained with this methodology are highly uncertain when applied to specific situations.

### 1.H.4.2.3.2 Additional Resources

Estimating or measuring nitrous oxide emissions from agricultural soils is a developing science and methodologies and models are changing rapidly. Direct field-scale measurements can be accomplished by either soil chamber or micrometeorological methods. At present both approaches are expensive and difficult to execute. As a result, use of direct field-scale measurement methods are typically limited to research applications. Additional information on these measurement techniques can be found in Laville, *et al.*, 1997 and Hatfield and Baker, 2004.

Two models are available for acquiring default values for nitrous oxide emissions from agricultural soils. The Nitrate Leaching and Economic Analysis Package (NLEAP) is a field-scale computer model developed to provide a rapid and efficient method of determining potential nitrate leaching and nitrous oxide emissions associated with agricultural practices. It combines basic information about on-farm management practices, soils, and climate, and then translates the results into projected budgets for nitrogen.[176]

The second model option is the DAYCENT model. DAYCENT is a dynamic daily time-step model that simulates exchanges of carbon, nitrogen (N), and phosphorus (P) between the atmosphere, soil, and plants that result from plant growth and events such as fire, grazing, cultivation, harvest, and organic matter or fertilizer additions. The EPA, USDA's Agriculture Research Service, and the Natural Resources Ecology Laboratory at Colorado State University, are working together to evaluate the utility of the DAYCENT model in providing estimates of

[176] See web site: www.wcc.nrcs.usda.gov/nutrient/nutrient-nitrogen.html.

$N_2O$ emissions related to agricultural soil management practices.

All practices designed to reduce emissions should be consistent with the practice standard and specifications for Nutrient Management (590). Entities developing site-specific measurements or model-based estimates for nitrous oxide emissions from soils must follow the guidelines for new methods provided in Chapter 1, Part A, Section A.4.

#### 1.H.4.2.4 Lime Applications

Lime, in the form of limestone or dolomite, is often added to agricultural soils to reduce acidic conditions. Lime contains carbonate compounds that release carbon dioxide through the bicarbonate equilibrium reaction when added to soils (IPCC 1997). The amount of emissions from this source is uncertain -- a single, simple approach to calculating the amount is provided below.

##### 1.H.4.2.4.1 Inference Using Default Emission Factors

**Rating: B**

carbon dioxide emissions from limestone and dolomite applications can be estimated from the amount of lime applied. The amount applied, in metric tons, over the course of a year is multiplied by the emission factors provided in Table 1.H.21. Separate factors are provided for limestone and dolomite. Emissions from limestone and dolomite are totaled to yield an entity estimate of emissions from lime.

$$CO_2 = \sum Lime_i * EF_i$$

**Where:**

**$Lime_i$ = amount of lime applied as limestone or dolomite (metric tons)**

**$EF_i$ = emission factor limestone or dolomite (tons $CO_2$/ton applied)**

### Table 1.H.21. Emission factors for limestone and dolomite applications

| | Emission factor (tons $CO_2E$ / ton applied) |
|---|---|
| Limestone | 0.44 |
| Dolomite | 0.48 |

Source: Environmental Protection Agency. 2005. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2003. Chapter 7 (page 245, multiply values on page 245 by 3.67 to convert emissions from units of carbon to units of carbon dioxide).

### 1.H.4.3 Agricultural Soil Carbon Emissions and Sequestration

Entities can estimate and report carbon dioxide emissions and sequestration associated with cropping practices and grazing land management. Carbon dioxide emissions and sinks in soils

are related to how much organic carbon is stored in soils (IPCC 1997). Change in the organic carbon content of soil is based on the balance between carbon inputs (e.g., atmospheric carbon dioxide fixed as carbon in plants through photosynthesis) and losses (e.g., decomposition of soil organic matter). The net balance of carbon dioxide uptake and loss in soils is affected by soil characteristics and climate. Land use and management also affect the net balance of carbon dioxide through modifying inputs and rates of decomposition. Changes in agricultural practices such as clearing, drainage, tillage, crop selection, grazing, crop residue management, fertilization, irrigation, and flooding can modify both organic matter inputs and decomposition, and thereby result in a net flux of carbon dioxide to or from soils.

Most agricultural soils contain comparatively low amounts of organic carbon as a percentage of total soil mass, typically in the range of 0.5 to 3.0 percent for soil between the surface and a depth of 25 to 30 centimeters (cm). However, on an area basis, this amount of carbon typically exceeds the amount stored in vegetation in most ecosystems (including forests). Conversion of native ecosystems to agricultural uses has resulted in large losses of soil carbon -- as much as 30 to 50 percent or more (Haas, *et al.* 1957, Schlesinger 1986). After many decades of cultivation, however, most soils have likely stabilized at lower carbon levels or are increasing their organic matter levels as a result of increasing crop productivity (providing more residues), less intensive tillage, and other changes in agricultural management practices (Paustian, *et al.* 1997a,b; Allmaras, *et al.* 2000; Follett 2001). Changes in land-use or management practices that result in increased organic inputs or decreased oxidation of organic matter (e.g., taking cropland out of production, improved crop rotations, cover crops, application of organic amendments and manure, and reduction or elimination of tillage) will result in a net accumulation of soil organic carbon until a new equilibrium is achieved.

Organic soils (histosols) contain more than 20 to 30 percent organic matter by weight. These soils form under waterlogged conditions, which slows decomposition of plant residues. When organic soils are drained and cultivated the rate of decomposition and carbon dioxide emissions are greatly accelerated. Carbon loss from cultivated organic soils can continue over long periods of time because of the depth and richness of the organic layers. Unless restored to undrained, anaerobic conditions, cultivated organic soils remain a net source of carbon dioxide.

Carbon dioxide is also fixed as organic carbon in perennial biomass (e.g., trees, shrubs, and grasses) through photosynthesis. This carbon remains stored in biomass until released by decomposition. Agroforestry practices such as establishing windbreaks and riparian forest buffers can lead to carbon sequestration in both soil and biomass. Methods for estimating carbon fluxes in agroforestry systems are provided in Part I of this Chapter. Carbon fluxes on forestlands within the boundaries of agricultural entities also should be estimated following the guidance in Part I.

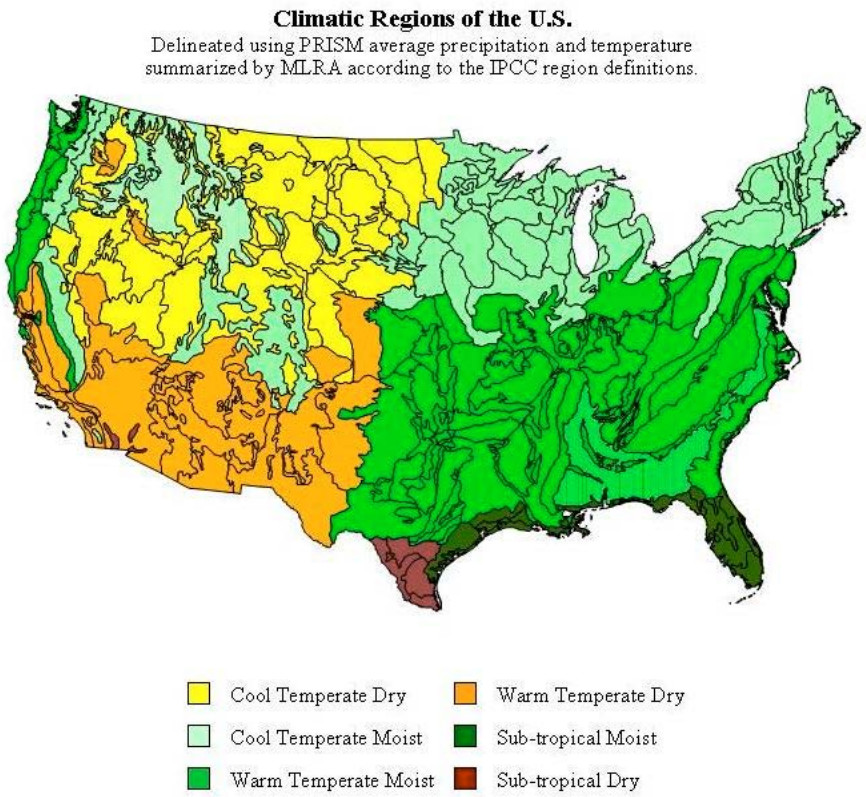
### 1.H.4.3.1 Characterizing the Land Base

The methods below require entities to first characterize the croplands and pasture/grazing lands on which they are reporting by soils, management practices, and climate regions. At the broadest level, entities will need to classify croplands and pasture/range lands into organic and mineral soils. Emissions estimates for cultivated mineral soils (i.e., mineral soils on croplands) require

soils to be further subdivided into general classes of soil as defined in the methods below.

Similar to livestock emissions estimates, an entity may need to determine its climate region(s) to employ the most specific default emission/sequestration factors available. The regions specified in the default tables are shown in Map 1.H.1.

**Map 1.H.1**




Three methods are provided below for estimating carbon dioxide fluxes on mineral agricultural soils. A single, simple method is provided to estimate emissions of carbon dioxide from organic soils. Reporters will need to estimate and report carbon dioxide fluxes on mineral soils separately from carbon dioxide emissions on organic soils.

## 1.H.4.3.2 Carbon Dioxide Fluxes on Mineral Soils

### 1.H.4.3.2.1 Inference Using Default Emission and Sequestration Factors

**Rating: C**

This approach estimates carbon dioxide emissions and sequestration separately, then sums the two to obtain a net balance of carbon dioxide emissions/sequestration in soils. Methods for estimating emissions and sequestration are provided separately below. By convention, sequestration is considered a negative emission and is represented with a negative number.

1.H.4.3.2.1.1 Emissions Conventional tillage disturbs the soil and accelerates the oxidation of carbon compounds in it. If tillage practices have been in place for a significant length of time (more than 20 years) it is likely that the soil carbon is in equilibrium and is neither a source nor a sink of carbon. When perennial vegetation is initially plowed, soil carbon loss is rapid. In general, about 40 percent of the total soil carbon is lost in the first few years after initial cultivation.

Reporters should determine the area of mineral soils under conventional tillage. Most agricultural entities will be contained within a single climate region and should use the appropriate regional factors. Separate calculations for each climate region are necessary for those entities owning agricultural land in more than one climate region.

The next step is to estimate carbon dioxide losses from mineral soils. Emissions are assumed to occur only in the first year of cultivation. Emissions are estimated by multiplying the area cultivated by the emissions factors in Table 1.H.22. The emissions factors account for a 40 percent loss of soil carbon. After the first year of cultivation, it should be assumed there are no additional losses of carbon dioxide. It is important to note that cropland will often have been under cultivation for several years before the base period of the Voluntary Reporting of Greenhouse Gases Program. In these cases, reporters should not report carbon dioxide emissions from soils.

**Table 1.H.22: $CO_2$ emissions factors by soil type after first year of cultivation**

| | | Climate regions | | | | | |
|---|---|---|---|---|---|---|---|
| IPCC Soil Categories | USDA Taxonomic Soil Orders | Cold | | Warm | | | |
| | | Temperate | | Temperate | | Subtropical | |
| | | Dry | Moist | Dry | Moist | Dry | Moist |
| | | tons $CO_2$/ha | | | | | |
| High clay activity mineral soils | Vertisols, mollisols, inceptisols, aridisols, and high base status alfisols | 62 | 95 | 54 | 75 | 62 | 84 |
| Low clay activity mineral soils | Ultisols, oxisols, acidic alfisols, and many entisols | 66 | 76 | 37 | 59 | 57 | 69 |
| Sandy soils | Any soils with greater than 70% sand and less than 8% clay (often Entisols) | 35 | 59 | 23 | 44 | 48 | 73 |
| Volcanic soils | Andisols | 182 | 167 | 182 | 182 | 182 | 188 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Spodic soils | Spodosols | 126 | 109 | 126 | 157 | 126 | 126 |
| Aquic soils | Soils with aquic suborder | 126 | 131 | 70 | 75 | 92 | 70 |

Source: Environmental Protection Agency. 2003. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001. Annex P. Table P.2 on page P-2. Values in Table P.2 were first multiplied by 3.67 to convert carbon units to $CO_2$ equivalents and then multiplied by 0.4 (see note below).
Note: Factors were calculated as 40 percent of the carbon stocks published in EPA 2003, which were estimated from pedon data in the database of the National Soil Survey Center, USDA NRCS (1997) for the top 30 cm of the soil profile.

1.H.4.3.2.1.2 Sequestration Reducing soil disturbance and/or increasing plant productivity will increase soil carbon. Table 1.H.23 provides sequestration coefficients for soil carbon increases. Increases will occur annually for a period of years following the adoption of conservation practices. The sequestration rates in Table 1.H.23 are the midpoint of ranges for the sequestration potential of agricultural management practices published in Follett (2001) and Lal, *et al.* (1998).

The disruption of practices listed in Table 1.H.23 can result in the cessation of carbon sequestration and even cause a rapid loss of soil carbon. For example, increases in soil carbon gained from using reduced tillage for many years will be rapidly lost if a farmer reverts to conventional tillage.

Most of the research studies on which the sequestration factors are based were conducted in agricultural systems that receive between 10 and 50 inches of precipitation per year—the greater the rainfall, the greater potential to sequester carbon. For instance, years with less-than-average precipitation can result in reduced sequestration of carbon, or even losses of soil carbon if the drought is sufficiently severe. Typically, if a management regime is in place for an extended period of time (approximately 20 years), soil carbon will equilibrate and the quantity will not change unless there is a change in inputs, tillage practices, or weather.

The first step in quantifying sequestration levels is to estimate the amount of land on which each of the management practices in Table 1.H.23 is in use. For lands on which these practices have been in use for less than 20 years, multiply the land area by the sequestration rate provided. This sequestration rate can be assumed each year for 20 years as long as the management practice is implemented continuously. Twenty years after the adoption of a practice (assuming that the practice was implemented continuously for 20 years), no annual changes in soil carbon stocks should be reported. If no till, mulch till, or ridge till practices cease at any point and are replaced by conventional till, carbon emissions occur and are equal to the gains recorded up to that point as a result of no till, mulch till, or ridge till.

Carbon dioxide emissions from agricultural soils are affected by a variety of site specific factors beyond the control of managers, specifically precipitation, soil temperature, soil texture and soil moisture. The default estimates provided in this method do not account for site-to-site variations and are highly uncertain.

## Table 1.H.23. Potential rates of carbon sequestration

| Practice | Description | Sequestration factor (kg $CO_2$/ha/yr) |
|---|---|---|
| Improved rangeland management | Grazing management[1], Riparian management[2], Prescribed burning[3] | 300 |
| Improved pastureland management--fertilizer application | Applying nutrients consistent with plant uptake requirements[4] | 900 |
| Improved pastureland management--improved forage species | Planting species adapted to soils, climate and grazing needs[5] | 730 |
| Improved grazing management on pasture | Rotational grazing, improved forage systems[6] | 2,900 |
| Restoration of mined lands | Establishing vegetation on mined soils[7] | 6,400 |
| Conversion of cropland to improved pasture | Establishing adapted species on formerly cropped land[8] | 2,900 |
| Conversion of cropland to natural vegetation | Establishing native vegetation on formerly cropped land[9] | 2,800 |
| Conversion from conventional to no till and maintaining no till for 20 years | Leaving crop residue on soil surface, planting in narrow bands[10] | 1,300 |
| Conversion from conventional to mulch till, or ridge till and maintaining mulch or ridge till for 20 years | Leaving adequate residue on soil surface through out the year[11] | 900 |

Source: Sequestration factor reflect midpoints of ranges published in Follett 2001 and Lal, *et al*. 1998
1. Consistent with Prescribed Grazing Standard and Specification (528).
2. Consistent with Riparian Cover Standard and Specification (390).
3. Consistent with Prescribed Burning Standard and Specification (338).
4. Consistent with Nutrient Management Standard and Specification (590).
5. Consistent with Pasture and Hayland Planting Standard and Specification (512).
6. Consistent with Prescribed Grazing Standard and Specification (528).
7. Consistent with Abandoned Land Reconstruction Mined Land (543).
8. Consistent with Pasture and Hayland Planting Standard and Specification (512).
9. Consistent with Pasture and Hayland Planting (512), Tree and Shrub Planting (612), Early Successional Habitat Establishment (647), Range Planting (520).
10. Consistent with Residue Management Standard and Specification (329).

### 1.H.4.3.2.2 Model-based Estimates of $CO_2$ Flux on Mineral Soils

**Rating: A or B**

USDA's Natural Resources Conservation Service, in collaboration with researchers at the Natural Resources Ecology Laboratory at Colorado State University, developed the CarbOn Management Evaluation Tool (COMET-VR) to help entities obtain default estimates of annual soil carbon fluxes for purposes of reporting under the 1605(b) Voluntary Reporting of Greenhouse Gases Program. COMET-VR is a web-based calculation tool that allows users to estimate changes in mineral soil carbon storage on cultivated lands for most regions and cropping systems prevalent in the United States.

The COMET-VR system has a simple interface where users provide basic information about a parcel of land including soil characteristics and land management and COMET-VR provides estimates of annual soil carbon flux. COMET-VR also produces an uncertainty analysis of the soil carbon flux estimates to help reporters assess the precision of these values. The measure associated with this analysis is important to reporters because it indicates whether a carbon flux measure obtain using COMET-VR is rated as an A or a B method. When the model inputs closely match actual conditions on the entity, the corresponding uncertainty estimate will be low. For uncertainty estimates less than or equal to 15 percent, COMET-VR may be treated as an A rated method. When model inputs are not a good match for actual conditions on the entity, the corresponding uncertainty estimate will be high. For uncertainty estimates greater than 15 percent, COMET-VR should be treated as a B rated method.

Specific information requirements and guidance on using COMET-VR to estimate and report soil carbon fluxes for the 1605(b) Program are detailed in the Appendix to Chapter 1, Part H of the Technical Guidelines. This Appendix also provides the rationale for, and detailed description of, the methods used to estimate soil carbon flux for different agricultural practices and regions in the United States.

COMET-VR is available online at the website: http://www.cometvr.colostate.edu/.

Entities developing agricultural soil carbon flux estimates using other models must follow the guidance on new methods in Chapter 1, Part A, Section A.4.

### 1.H.4.3.2.3 Direct Measurement of Mineral Soil Carbon Stocks

**Rating: A or B**

Periodic soil carbon sampling can provide highly reliable estimates of carbon stocks and fluxes for particular fields. Entities wishing to employ this approach should review the protocols outlined in the Australian Greenhouse Office Technical Report No. 14 (Australia 2000), the USDA NRCS Soil Survey Laboratory Methods Manual, Version 4 (USDA NRCS 2004)[177], and Chapters 9 and 10 in "Assessment Methods for Soil Carbon" by Lal, *et al.* (2001). These documents provide standardized techniques for collecting, preparing, and analyzing soil

[177] Burt, R. (ed.). 2004. *NRCS Soil Survey Laboratory Methods Manual Version 4*. USDA NRCS.

samples. All laboratory analysis must be performed consistent with technical standards described in the Soil Science Society Book Series Numer 5 (Part 1, 1986, ed A. Klute; Part 2, 1994, ed. R.W. Weaver, S. Angle, and P. Bottomly; Part 3, 1996, ed. D.L. Sparks; and Part 4, 2002, ed. J.H. Dane and G.C. Topp).

Developing an efficient sampling system requires attention to the following basic steps (Smith 2001):

- Determine an acceptable level of uncertainty or error (see below for a discussion on uncertainty levels).
- Make a preliminary determination of the amount and structure of variability inherent within a population and then stratify samples to minimize the variation.
- Adjust sampling protocols to optimize the cost in relation to error.

*Stratifying samples to estimate soil carbon*: At a minimum, fields or groups of fields should be stratified by the following:

- Soil map unit (component if map unit is an association) using National Cooperative Soil Survey Report for the area. Soil surveys can be obtained from the local NRCS field office or at the USDA website: http://soils.usda.gov/
- Management system (cropping system, tillage practice)
- Topographic position (ridge, slope, toe, aspect)
- Microtopography (depression, hummock)

Within each stratum, sample points may be randomly placed or systematically distributed in a grid pattern. Use the equation below to determine the appropriate number of samples to meet a desired level of statistical error. In general, increasing the number of samples will decrease the error. Several iterations may be necessary to determine the appropriate number of samples.

$$n = (t * s/E)^2$$

**Where:**

| | | |
|---|---|---|
| **n** | **=** | **number of samples** |
| **t** | **=** | **estimate of the statistical distribution of the variance for a given degrees of freedom and confidence interval, taken from table of Student's t distribution** |
| **s** | **=** | **standard deviation of the soil samples** |
| **E** | **=** | **desired confidence interval** |

In this equation, *n* is the number of samples required and *t* is a value taken from a table of the Student's t distribution (an estimate of the statistical distribution of the variance for a given degrees of freedom and confidence interval). The standard deviation of the soil samples (*s*) and the half width of the desired confidence interval (*E*) must be approximated to make a preliminary estimate for *n*. Approximations of *s* and *E* can be derived from published analyses of soil

samples.

The value for *t* is taken from a standard table of values available in most statistical textbooks and depends on a given sample size. Begin with an initial approximation of the sample size and use this to choose a t-value. Estimate *n* using this t-value and the equation above. The solution for *n* is reached when the sample size used to choose a t-value matches or is slightly greater than the *n* calculated from the equation. More detail can be found in most statistical textbooks on using this approach to determine the sample size needed to estimate a mean value within a given level of certainty.

Samples may be collected in two different ways: randomly within a stratum during succeeding sampling dates, or in time separate pairs where pairs of points are relocated in succeeding sampling dates to determine change (Kimble, *et al.* 2001). In either case, the estimate is of change in carbon stock over time. To insure consistency, sampling should be conducted at the same time of year.

*Extracting samples:* To estimate changes in soil carbon, a soil sample should be extracted to a depth defined by the A horizon in the map unit description of the Soil Survey (soil surveys can be obtained from the local NRCS field office or at the USDA web site: http://soils.usda.gov/.

As a default, soil may be extracted to a depth of 25 cm. Extraction of samples is best accomplished with a sampling tube.

*Estimating the carbon in a sample:* Only certified laboratories can estimate the organic carbon content of soil samples. The local land grant university is usually the best provider of this service. Most laboratories report on the basis of percent carbon in the sample.

*Estimating the carbon in a field or fields:* The amount of carbon in a field or fields at any point in time should be expressed as metric tons carbon (C) per hectare to a consistent depth. Extrapolating from a point to a field level requires converting the percent C in a sample to an absolute amount per volume of soil. Soil volume (expressed as bulk density) can change as carbon changes, thus it is best to have estimates of bulk density made by the same laboratory selected to estimate soil organic carbon.

Bulk density of soil is usually expressed as grams per cubic centimeter (g/cc). Multiplying the weight of the soil per volume (g/cc) by depth (cm) of the soil sampled by 1000 ($cm^2/m^2$) will yield weight of soil per square meter ($g/m^2$). Dividing by 100 will yield MT soil/ha to depth (MT = metric tons). Determining absolute carbon requires then multiplying by the percent C in a sample. The result should be MT C/ha multiplied by the number of ha in each strata. Summing over all strata should yield the total amount of carbon.

*Frequency of sampling:* Changes in soil carbon occur relatively slowly. It is difficult to detect small changes (less than 1 MT C/ha) over any time period. The time separating sampling dates to assess reportable changes in soil carbon should not be less than 3 years and not more than 5 years. Estimates of changes in soil carbon pools using this method can have low uncertainty. The use of statistical techniques allows for the calculation of a standard error of the mean that is a

quantitative estimate of uncertainty.

### 1.H.4.3.3 $CO_2$ Emissions on Cultivated Organic Soils

As in mineral soils, both carbon dioxide emissions and sequestration may occur in organic soils, although as long as organic soils are cultivated they continue to be a net source of carbon dioxide emissions. Emissions may be reduced through practices such as water table management and taking lands out of cultivation. Once taken out of cultivation, it is likely that soil carbon stocks rebuild gradually over time, although reliable information on annual rates of carbon sequestration in organic soils taken out of cultivation is not currently available. This method therefore takes into consideration emissions only from organic soils, and the method below provides a rough estimate of emissions from organic soil cultivation. While management practices such as water table management are believed to reduce carbon dioxide emissions, the best available methods do not take management impacts into consideration. This methodology will only capture changes in carbon dioxide emission from organic soils that occur when lands are taken out of production.

#### 1.H.4.3.3.1 Inference Using Default Emissions Factors

**Rating: B**

Once organic soils are put under cultivation, carbon losses typically continue until the organic soil layer has been completely depleted (IPCC 1997). carbon dioxide losses are thus assumed to continue after soils are initially cultivated and are reported each year. To estimate carbon dioxide losses from organic soils, divide the area of organic soils into those on which crops are produced and those used for pasture; include pasturelands in the estimate if they were cultivated and planted with forage species (e.g., grasses and legumes) and used for grazing. Assume zero emissions from uncultivated pastures on organic soils. Multiply the area of organic soils by the appropriate emission factors provided in Table 1.H.24.

### Table 1.H.24. Emission factors for $CO_2$ emissions from cultivated organic soils

| Climate Region | Cropland (tons $CO_2$/ha-yr) | Cultivated Pastures (tons $CO_2$/ha-yr) |
|---|---|---|
| Cold temperate, dry and moist | 41.10 | 10.28 |
| Warm temperate, dry and moist | 51.38 | 12.85 |
| Subtropical, dry and moist | 51 .38 | 12.85 |

Source: Environmental Protection Agency. 2003. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2001*. Annex P (Table P.6 on page P-5). Multiply values in Table P-6 by 3.67 to convert from units of carbon to units of $CO_2$.

#### 1.H.4.3.3.2 Direct Measurement of Organic Soil Carbon Stock Change

**Rating: A or B**

carbon dioxide emissions from organic soils can be estimated by measuring the annual changes

in soil carbon stocks. Cultivated organic soils typically lose carbon annually in the form of carbon dioxide emissions. Annual changes in soil carbon stocks can be measured with a systematic sampling method applied in the field. Such field methods draw on the soil sampling methods described in subsection 1.H.4.3.2.3 to estimate initial carbon stocks. In addition, physical soil carbon losses are measured by establishing a benchmark and measuring annual changes relative to that benchmark.

Carbon in organic soils should be measured similarly to mineral soils with the exception of depth of measurement. Organic soils should be sampled to a depth of 1m or to the water table if less than 1m. Just as in mineral soils, C content per volume of soil should be determined by calculation of bulk density and adjustment for area extent. If cultivated organic soils are converted to wetlands by abandoning cultivation, reestablishing native vegetation and reestablishing the water table, benchmark conditions should be adjusted to calculate soil C in a similar volume of soil as post watering conditions.

The sampling method described above can be used to develop an A or B rated estimate of carbon dioxide emissions from organic soils. Sampling methods have the potential to yield relatively certain estimates of changes in carbon stocks on organic soils. As with the mineral soil sampling method, estimates derived from a sampling program for organic soils should receive an A rating when the associated uncertainty levels are less than or equal to 15 percent. The use of a sampling program, however, does guarantee a high level of certainty. Therefore if associated uncertainty levels are greater than 15 percent the estimates should be rated a B.

**Table 1.H.25. Metabolizable Energy (ME) by Feed Type (for Enteric Fermentation)**

| Feed No. | Feed Type | Mcal/kg |
|---|---|---|
| 101 | Bahiagrass, 30% Dry Matter | 1.95 |
| 102 | Bahiagrass, Hay | 1.84 |
| 103 | Bermudagreass, Late Vegetative | 1.77 |
| 104 | Brome Hay, Pre-Bloom | 2.17 |
| 105 | Brome Hay, Mid-Bloom | 2.02 |
| 106 | Brome Hay, Late Bloom | 1.99 |
| 107 | Brome Hay, Mature | 1.92 |
| 108 | Fescue, Meadow Hay | 2.02 |
| 109 | Fescue Alta, hay | 1.99 |
| 110 | Fescue K31, Hay | 2.21 |
| 111 | Fescue K31, Hay, Full Bloom | 2.10 |
| 112 | Fescue K31, Mature | 1.59 |
| 113 | Napiergrass, Fresh 30 day DM | 1.99 |
| 114 | Napiergrass, Fresh 60 day DM | 1.92 |
| 115 | Orchardgreass, Hay, Early Bloom | 2.35 |
| 116 | Orchardgreass, Hay, Late Bloom | 1.95 |
| 117 | Pangolagrass, Fresh | 1.99 |
| 118 | Red Top, Fresh | 2.28 |
| 119 | Reed Canarygrass, Hay | 1.99 |
| 120 | Ryegrass, Hay | 2.31 |
| 121 | Sorghum-Sudan, Hay | 2.03 |

| Feed No. | Feed Type | Mcal/kg |
|---|---|---|
| 122 | Sorghum-Sudan, Pasture | 2.35 |
| 123 | Sorghum-Sudan, Silage | 1.99 |
| 124 | Timothy Hay, Late Vegetative | 2.24 |
| 125 | Timothy Hay, Early Bloom | 2.13 |
| 126 | Timothy Hay, Mid Bloom | 2.06 |
| 127 | Timothy Hay, Full Bloom | 2.02 |
| 128 | Timothy Hay, Seed Stage | 1.70 |
| 129 | Wheatgrass, crest. Hay | 1.92 |
| 135 | Grass Pasture, Spring | 2.68 |
| 136 | Grass Pasture, Summer | 2.42 |
| 137 | Grass Pasture, Fall | 1.92 |
| 138 | Mix Pasture, Spring | 2.86 |
| 139 | Mix Pasture, Summer | 2.42 |
| 140 | Range, June Diet | 2.35 |
| 141 | Range, July Diet | 2.25 |
| 142 | Range, August Diet | 2.15 |
| 143 | Range, September Diet | 2.07 |
| 144 | Range, Winter | 1.83 |
| 145 | Meadow, Spring | 1.62 |
| 146 | Meadow, Fall | 1.88 |
| 147 | Meadow, Hay | 2.17 |
| 148 | Prairie, Hay | 1.74 |
| 201 | Alfalfa Hay, Early Vegetative-S | 2.39 |
| 202 | Alfalfa Hay, Early Vegetative-N | 2.42 |
| 203 | Alfalfa Hay, Late Vegetative-S | 2.28 |
| 204 | Alfalfa Hay, Late Vegetative-N | 2.31 |
| 205 | Alfalfa Hay, Early Bloom-S | 2.17 |
| 206 | Alfalfa Hay, Early Bloom-N | 2.24 |
| 207 | Alfalfa Hay, Mid Bloom-S | 2.10 |
| 208 | Alfalfa Hay, Mid Bloom-N | 2.17 |
| 209 | Alfalfa Hay, Full Bloom-S | 1.99 |
| 210 | Alfalfa Hay, Full Bloom-N | 2.02 |
| 211 | Alfalfa Hay, Late Bloom-S | 1.88 |
| 212 | Alfalfa Hay, Late Bloom-N | 1.92 |
| 213 | Alfalfa Hay, Mature-S | 1.81 |
| 214 | Alfalfa Hay, Seeded | 1.63 |
| 215 | Alfalfa Hay, Weathered | 1.74 |
| 216 | Alfalfa Hay, dehydrated 15%CP | 2.13 |
| 217 | Alfalfa Silage, Early Bloom | 2.28 |
| 218 | Alfalfa Silage, Mid Bloom | 2.10 |
| 219 | Alfalfa Silage, Full Bloom | 1.99 |
| 220 | Birdsfoot, Trefoil, Hay | 2.13 |
| 221 | Clover, Ladino Hay | 2.17 |
| 222 | Clover, Red Hay | 1.99 |
| 223 | Vetch Hay | 2.06 |
| 224 | Leg Pasture, Spring | 2.86 |
| 225 | Leg Pasture, Summer | 2.39 |

| Feed No. | Feed Type | Mcal/kg |
|---|---|---|
| 301 | Barley, Silage | 2.17 |
| 302 | Barley, Straw | 1.45 |
| 303 | Corn Cobs, Ground | 1.81 |
| 304 | Corn Silage, 25% Grain-N | 2.46 |
| 305 | Corn Silage, 25% Grain-S | 2.21 |
| 306 | Corn Silage, 35% Grain | 2.49 |
| 307 | Corn Silage, 40% Grain | 2.39 |
| 308 | Corn Silage, 40% GR + NPN | 2.42 |
| 309 | Corn Silage, 40% GR + NPN + ca | 2.46 |
| 310 | Corn Silage, 45% Grain | 2.60 |
| 311 | Corn Silage, 45% GR + NPN | 2.84 |
| 312 | Corn Silage, 45% GR + NPN + ca | 2.71 |
| 313 | Corn Silage, 50% Grain | 2.71 |
| 314 | CS50% + NPN + CA | 2.98 |
| 315 | Corn Silave, Immature (no Ears) | 2.35 |
| 316 | Corn Silage, Stalkage | 1.99 |
| 317 | Corn Stalks, Grazing | 2.38 |
| 318 | Oat, Silage Dough | 2.13 |
| 319 | Oat, Straw | 1.63 |
| 320 | Oat, Hay | 1.92 |
| 321 | Sorghum, Silage | 2.17 |
| 322 | Wheat, Silage dough | 2.06 |
| 323 | Wheat, Straw | 1.48 |
| 401 | Barley Malt, Sprouts w/hulls | 2.57 |
| 402 | Barley Grain, Heavy | 3.04 |
| 403 | Barley Grain, Light | 2.78 |
| 404 | Corn, Hominy | 3.29 |
| 405 | Corn Grain, Cracked | 3.25 |
| 406 | Corn Dry, Ear 45 lb/bu | 2.78 |
| 407 | Corn Dry, Ear 56 lb/bu | 2.96 |
| 408 | Corn Dry, Grain 45 lb/bu | 3.18 |
| 409 | Corn Ground, Grain 56 lb/bu | 3.18 |
| 410 | Corn Dry, Grain 56 lb/bu | 3.18 |
| 411 | Corn Grain, Flaked | 3.36 |
| 412 | Corn HM, ear 56 lb/bu | 3.07 |
| 413 | Corn HM, Grain 45 lb/bu | 3.25 |
| 414 | Corn HM, Grain 56 lb/bu | 3.36 |
| 415 | Cottonseed, Black Whole | 3.43 |
| 416 | Cottonseed, High Lint | 3.25 |
| 417 | Cottonseed, Meal - mech | 2.82 |
| 418 | Cottonseed, Meal - Sol-41%CP | 2.71 |
| 419 | Cottonseed, Meal - Sol-43%CP | 2.71 |
| 420 | Molasses, Beet | 2.71 |
| 421 | Molasses, Cane | 2.60 |
| 422 | Oats, 32 lb/bu | 2.64 |
| 423 | Oats, 38 lb/bu | 2.78 |
| 424 | Rice, Bran | 2.53 |

| Feed No. | Feed Type | Mcal/kg |
|---|---|---|
| 425 | Rice Grain, Ground | 2.86 |
| 426 | Rice Grain, Polished | 3.22 |
| 427 | Rye Grain | 3.04 |
| 428 | Sorghum, Dry grain | 2.75 |
| 429 | Sorghum, Rolled grain | 2.96 |
| 430 | Sorghum, Steam flaked | 3.18 |
| 431 | Tapioca | 3.04 |
| 432 | Wheat, Ground | 3.18 |
| 433 | Wheat Middlings | 3.00 |
| 434 | Wheat Grain, Hard red spring | 3.04 |
| 435 | Wheat Grain, Soft white | 3.07 |
| 501 | Brewers Grain, 21% Dry Matter | 2.53 |
| 502 | Brewers Grain, Dehydrated | 2.39 |
| 503 | Canola, Meal | 2.49 |
| 504 | Coconut, Meal | 2.31 |
| 505 | Corn Gluten, Feed | 2.89 |
| 506 | Corn Gluten, Meal | 3.04 |
| 507 | Corn Gluten, Meal 60% CP | 3.22 |
| 508 | Distillers Gr., + solubles | 3.18 |
| 509 | Distillers Gr., Dehy - Light | 3.18 |
| 510 | Distillers Gr., Dehy - Inter. | 3.18 |
| 511 | Distillers Gr., Dehy - Dark | 3.18 |
| 512 | Distillers Gr., Dehy - V. Dark | 3.18 |
| 513 | Distillers Gr., solubles dehy | 3.18 |
| 514 | Distillers Gr., Wet | 3.25 |
| 515 | Lupins | 2.82 |
| 516 | Peanut, Meal | 2.78 |
| 517 | Soybean, Meal - 44 | 3.04 |
| 518 | Soybean, Meal - 49 | 3.15 |
| 519 | Soybean, Whole | 3.40 |
| 520 | Soybean, Whole Roasted | 3.40 |
| 521 | Sunflower, Seed meal | 2.35 |
| 601 | Apple, Pomace | 2.49 |
| 602 | Bakery, Waste | 3.22 |
| 603 | Beet Pulp, + Steffen's filt | 2.39 |
| 604 | Beet Pulp, Dehydrated | 2.68 |
| 605 | Citrus Pulp, Dehydrated | 2.96 |
| 606 | Grape, Pomace | 1.19 |
| 607 | Soybean, Hulls | 2.89 |
| 608 | Linseed, Meals | 2.82 |
| 609 | Cottonseed, Hulls | 1.63 |
| 610 | Wheat, bran | 2.53 |
| 701 | Bloodmeal | 2.39 |
| 702 | Feather, Meal | 2.46 |
| 703 | Fishmeal | 2.64 |
| 704 | Meat, meal | 2.57 |
| 705 | Tallow | 6.40 |

| Feed No. | Feed Type | Mcal/kg |
|---|---|---|
| 706 | Whey, Acid | 2.82 |
| 707 | Whey, Delact. | 2.57 |

Source: National Research Council. 1996. Nutrient Requirements for Beef Cattle, Seventh Revised Edition. Subcommittee on Beef Cattle Nutrition, Committee on Animal Nutrition, Board on Agriculture. National Academy Press. Washington, D.C.

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**Technical Guidelines for Voluntary Reporting of Greenhouse Gases Program**
**Chapter 1, Emission Inventories**

## Part I: Forestry Emissions

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# Technical Guidelines Chapter 1, Part I: Forestry Emissions

## 1.I.1 Overview

This Part supports and supplements the General Guidelines for reporting greenhouse gas information under Section 1605(b) of the Energy Policy Act of 1992 (EPAct), and provides additional detail for the forestry-sector component of Volume III, Section E.4, "Registering Reductions from Carbon Storage." The General Guidelines provide the rationale for the Voluntary Reporting of Greenhouse Gases Program and overall concepts and methods to be used in reporting. Before proceeding to the more specific discussion contained in this section of the Technical Guidelines, reporters should become familiar with the General Guidelines. This section relates the General Guidelines to the issues, methods, and data specific to creating an inventory for emissions and emission reductions associated with the forestry sector.

Appendices to this document provide detailed technical guidance for conducting inventories and estimating changes in carbon storage using different methods. Other sections of the Technical Guidelines address the sectors of electricity, residential and commercial buildings, industry, transportation, and agriculture.

The General Guidelines and supporting documents describe the rationale and processes for estimating emissions and analyzing emissions-reducing and carbon-sequestration activities. Certain procedures must be followed to calculate, report, and register reductions associated with increases in forest carbon stocks. This documentation is designed to provide the background needed to complete the reporting forms.

The Department of Energy (DOE) with the support of the U.S. Department of Agriculture, Forest Service (USDA Forest Service) and other agencies of the U.S. Government have designed this Voluntary Reporting of Greenhouse Gases Program to be flexible and easy to use. A variety of methods for making estimates of greenhouse gas emissions and reductions or sequestration are provided. The different methods range from simple and inexpensive to complex and costly. Reporters may choose the simplest available methods that provide estimates with a level of accuracy that meets reporting objectives. For example, "default" factors and estimates are provided for those wishing to enter data that are typical for forestry activities in a region, but that may not be sufficiently accurate for a specific entity to enable reductions to be registered. For estimates that are more specific to an entity or activity, measurement and modeling approaches are described for developing estimates.

As a supplement to the General Guidelines, this Part is intended to provide more specific guidance for developing an inventory of greenhouse gas (GHG) emissions and carbon sequestration related to forestry, and provide enough information and examples to enable reporters to make estimates and fill-out the Program's reporting forms. The guidance provided may need to be adapted to fit particular individual situations due to the great variety of entities and activities participating in the Program. The methods presented here have the scientific rigor necessary to account for carbon stock changes for activities or entities of any size, if they are used appropriately and supplemented if necessary by additional information or measurements.

This Part focuses on estimating changes in quantities of stored carbon as accurately as is practical considering the requirements for reporting and registering reductions. Accuracy clearly depends on accounting for all positive flows (emissions) of carbon from forests and negative flows (sequestration) of carbon to forests and wood products. Information presented in this section is consistent with protocols used to report changes in forest carbon stocks in greenhouse gas inventories compiled by the U.S. Environmental Protection Agency (EPA) and the U.S. Department of Agriculture (USDA). This is achieved through the use of consistent terminology, consistent definitions of ecosystem and wood product carbon pools, and consistent estimation approaches based on national forest inventory statistics.

### 1.I.1.1 Carbon Sequestration by the Forestry Sector

Forests remove carbon from the atmosphere and store it in vegetative tissue such as stems, roots, barks, and leaves. Certain forestry-sector activities can maintain or enhance this carbon sequestration. Through photosynthesis, all green vegetation removes carbon dioxide ($CO_2$) and releases Oxygen ($O_2$) to the atmosphere. The remaining carbon is used to create plant tissues and store energy. During respiration, carbon containing compounds are broken down to produce energy, releasing carbon dioxide in the process. Any remaining carbon is sequestered until the natural decay of dead vegetative matter or combustion releases it as carbon dioxide to the atmosphere. The net carbon stock in forests increases when the amount of carbon withdrawal from the atmosphere during photosynthesis exceeds the release of carbon to the atmosphere during respiration.

Some of the carbon in forests is released to the atmosphere during the harvesting of timber. However, whether or not the bulk of the carbon is released, and when, depends on the fate of the harvested timber. If the timber is used to make wood products, a portion of the sequestered carbon will remain stored for up to several decades or longer. If the harvested trees are burned and used to produce energy, carbon will be released through combustion, offsetting carbon that would have been released through the burning of fossil fuels. If the energy is not recovered, there will be no associated offset, and only carbon dioxide emissions from the burning of the wood. These cases demonstrate that harvested wood can sequester carbon for different time periods, and even potentially offset other emissions, depending upon its eventual use.

The forestry sector affects a broad range of potential greenhouse gas emission sources, emission reduction activities, and carbon sequestration activities. Examples include, but are not limited to, the following:

- Afforestation (the establishment of new forests on lands that have not been recently forested) can lead to large increases in carbon stocks on the treated area.

- Restoration of native vegetation and wildlife habitat has the additional potential to sequester large quantities of carbon.

- Reforestation (active regeneration of harvested forest land) can accelerate the natural regeneration process and provide for the establishment of fast-growing species.

- Agroforestry (the cultivation of trees with crops or pasture) can sequester carbon and potentially decrease the requirements for fossil fuel energy as well as energy-intensive chemicals in the production of food and fuel.

- Typical forest management practices may be modified to increase the rate of carbon sequestration or reduce emissions from the decay of specific forest carbon pools.

- Short-rotation woody biomass plantations can sequester carbon and provide energy feedstocks that displace fossil fuels in energy production.

- Protecting existing forests from harvest and/or from conversion to non-forest land use may prevent the release of carbon stocks.

- Low-impact harvesting methods can decrease emissions from soil disturbance and biomass decay that often follow timber harvest.

- Management of the carbon flows in the processing of harvested timber for wood products can reduce emissions from wood waste and energy used.

- Planting trees in urban areas (urban forestry) increases carbon sequestration and can reduce the energy used in heating or cooling homes and businesses.

The emission reductions and carbon sequestration activities in the forestry sector range from those that may be simple and relatively easy to evaluate (such as afforestation) to those with more complex effects (such as agroforestry and land restoration). The cost and feasibility of evaluating the emission reductions and sequestration are important factors to consider when selecting methods and deciding on how to report at the activity or entity level.

Accurately measuring the effects of forestry activities for entity or activity reporting can prove especially challenging. Nearly every action undertaken in the management of forests causes changes in biomass stocks, and therefore in net carbon flows. For example, tree planting establishes a new carbon sink; thinning forests shifts biomass increment to fewer trees; and harvesting removes stored carbon from the forest (but does not necessarily release all of it back into the atmosphere). Even the elimination of an activity, such as stopping the clearing of forests for agricultural use, can influence carbon flows by allowing forest regrowth and other natural processes to proceed uninterrupted.

Two important issues must be considered when measuring and estimating the effects of forestry activities on carbon flows for activity and entity reporting. The first is that forestry practices typically trigger ecosystem responses that change over time. For example, a newly established forest will take up carbon at a low rate initially, and then pass into a period of relatively rapid

carbon accumulation. The carbon uptake rate will then typically decline as growth is balanced against mortality in the older forest. From this point in time, standing live tree biomass may not increase, but evidence suggests that carbon may continue to flow into other forest carbon pools until the forest is removed by harvest or a natural disturbance event. Advanced measures of carbon flows must account for these dynamic effects.

The second issue is that the net effects of activities on carbon flows in forest ecosystems include many pools of carbon. Carbon accounting should be comprehensive, addressing the net effects of activities on all carbon flows. There are several carbon pools (such as aboveground biomass, belowground biomass, litter, soil, etc.) in forests. Forestry activities cause carbon to move between the various pools and to/from the atmosphere. . For example, forest management may be very effective at increasing the accumulation of biomass in commercially valuable forms—that is, in the trunks of commercial tree species. This increased growth may simply result from reducing competition from other types of trees, causing a transfer of carbon uptake from one group of trees to another. Forestry activities can also have effects on forest soils, woody debris, and the amount of carbon in wood products. The net carbon flow effects of any activity will be the sum of all the individual effects on the different carbon pools.

## 1.I.2 Estimation Methods

### 1.I.2.1 Carbon Pools

Forestry activities affect many different carbon pools. Table 1.I.1 highlights the key carbon pools that should be considered for measuring net carbon flows, using default estimates or models, and reporting. Definitions of many of the terms are included in the glossary. With the exception of harvested wood, estimates are directly associated with land area.

**Table 1.I.1 Relationships among Carbon Pools of Forest Ecosystems and Wood Products for Different Parts of Accounting Rules and Guidelines**

| Basic carbon pools for detailed measurement and estimation | Aggregated carbon pools used in default tables | Aggregated carbon pools for reporting |
|---|---|---|
| Live trees: above-ground | Live trees | Ecosystem carbon |
| Live trees: below-ground | | |
| Tree seedlings | Understory vegetation | |
| Shrubs, herbs, forbs, grasses | | |
| Standing dead trees: above-ground | Standing dead trees | |
| Standing dead trees: below-ground | | |
| Down dead wood | Down dead wood | |
| Stumps and dead roots | | |
| Fine woody debris | Forest floor | |
| Litter | | |
| Humus | | |
| Soil carbon | Soil carbon | |
| Harvested wood mass (total removed) | Harvested wood mass (in use and in landfills) | Wood products carbon |

| | | |
|---|---|---|
| | Harvested wood mass (burned for energy) | Not counted in emissions inventories because it is biogenic |
| | Harvested wood mass (emissions/not used for energy) | Not directly reported, but counted as a reduction in other forest carbon pools |

### 1.I.2.2 Greenhouse Gases

Forestry activities mainly affect the exchange of carbon dioxide between the land and the atmosphere, thus accounting for carbon stocks and flows is the primary focus of these accounting rules and guidelines. There may be cases where other greenhouse gases are significantly affected by an activity, and the General Guidelines specify that emissions greater than 3 percent of total emissions (in carbon-equivalent units) should be quantified. Of particular concern are nitrous oxide, which may be released from fertilized forests, and methane, which may be released from forested wetlands. Reporters should consider whether those gases are affected by their activities and estimate the net flows if significant. Note that no guidelines are provided in this section for monitoring, estimating, or reporting non-$CO_2$ gases for forestry. Reporters should consult the Technical Guidelines for other sectors if reporting non-$CO_2$ greenhouse gases is necessary.

### 1.I.2.3 Reporting Units

All final measures of net emissions and net emission reductions should be expressed in the form of carbon dioxide equivalent. For carbon, carbon dioxide equivalent is the weight of the gas, which is higher than the weight of the carbon alone because the gas also includes oxygen atoms. A simple multiplication factor, 3.67, can be used to convert carbon to carbon dioxide equivalent.

### 1.I.2.4 Units of Measurement

Both English and metric units of measurement are used in this section and associated appendices, and reporting will be allowed in both. Table 1.I.2 provides the most common conversion factors needed to change units of measurement from one system to the other. The following abbreviations are relevant to the conversion factors, and are used throughout the remainder of this section:

A = area
ac = acre
C = carbon
ha = hectare
I = inventory of carbon stock
MT/ha = metric tons per hectare
t/ac = short tons per acre

**Table 1.I.2 Conversion Factors for Units of Measurement**

| Measurement: | English Unit: | Metric Unit: |
|---|---|---|
| Area | 1 acre | 0.4047 hectares |
| Area | 2.47 acres | 1 hectare |
| Mass | 1 Short ton | 0.9072 metric tons |
| Carbon | 1 short ton per acre | 2.241 metric tons per hectare |
| Carbon | 892 pounds per acre | 1 metric ton per hectare |

### 1.I.2.5 Approaches to Calculations

#### 1.I.2.5.1 The Basic Carbon Stock Calculation

Calculating the quantity of carbon in an area of forest requires two pieces of information: the area of forest land included in the entity or activity, and the amount of carbon per unit of area. The following formula illustrates the basic calculation:

$$I = A \times C/ha$$

**Where:**

**I = inventory of carbon stock**

**A = area in hectares**

**C/ha = quantity of carbon stored per hectare (in metric tons per hectare).**

The variable C/ha must include estimates of all the relevant carbon pools. An estimate of harvested wood products for the activity or entity may also be required, but it may not be necessary to estimate that quantity on a per-hectare basis.

#### 1.I.2.5.2 Stock-Change Approach

Carbon flows from forests and forestry operations are typically estimated using changes in an inventory of carbon stocks. The general formula for calculating changes in carbon stocks is:

$$\text{Net annual carbon stock change in year } t = (I_t - I_{t-1})$$

**Where:**

**$I_t$ = inventory of carbon stock (in mass units such as short tons or metric tons) in the forest area in year t**

**$I_{t-1}$ = inventory of carbon stock (in mass units such as short tons or metric tons) in the forest area in the year immediately preceding t**

Since forest carbon stocks may change slowly relative to the size of the carbon stock, annual measurements or estimations of the inventory of carbon stock are unlikely to capture significant changes. It is therefore recommended that successive inventories be conducted over periods of 5 years. Net carbon flows should be estimated as the average annual difference in carbon stocks

between inventory years. For example, to estimate net average carbon stock change for a 5-year period, the estimate can be derived as:

$$\text{Net average annual carbon stock change} = (I_t - I_{t-5})/5$$

**Where:**

$I_{t-5}$ = **inventory of carbon stock in the forest area 5 years before the current year**

$I_t$ = **inventory of carbon stock in the forest area in the current year**

Reporting entities must establish an inventory for the base period to begin the estimation and reporting process, using an estimation method described in Section 1.I.2.6. The inventory must be updated each year for annual reporting. Updates may be provided using a combination of different estimation methods. For example, an entity may prepare an inventory for the initial year within the base period using the direct measurement approach, but not perform a second such measurement five years later. To submit reports for any reporting years between the initial and the second inventory, entities will need to estimate changes in carbon stocks relative to the initial year (within the base period) using default tables or a model. These estimates can then be corrected once the second measurement becomes available.

### 1.I.2.5.3 Flow Approach

For some carbon pools, such as carbon in soils, carbon stocks and changes in carbon stocks cannot easily be estimated, so a flow approach may be used to estimate changes in carbon stocks over a period of time. For example, a reporter may directly estimate annual flows of carbon using carbon dioxide flux monitoring methods or models of the impacts of activities on carbon flows. Carbon dioxide flux monitoring methods provide a direct estimate of the net exchange of carbon between the ecosystem and the atmosphere over short periods of time. Similarly, some ecosystem models simulate carbon flows at daily, monthly, or annual time periods based on data about the forest ecosystem and its physical characteristics, estimates of how processes such as photosynthesis affect carbon flows, and information about the effects of forest practices. Short-term estimates from monitoring or models can be extrapolated to estimate the net change in carbon stocks over a year.

If models or flux monitoring are used for annual estimates instead of successive inventories or direct measurement, it is recommended that inventories of carbon stocks be conducted periodically to verify that the activity or entity is actually behaving as the model or short-term flux monitoring predicts. If a discrepancy is detected, estimates should be adjusted to bring the reported flows back in line with measured carbon stocks.

### 1.I.2.5.4 Approaches for Wood Products

Additional accounting is required for carbon in wood that is removed from the forest. When timber is removed from the forest, the portion of its carbon that is released to the atmosphere depends upon how the timber is used. To illustrate, the burning timber releases the stored carbon immediately, whereas the carbon stored in lumber or furniture may not be emitted for decades. If carbon remaining in wood products is not part of the accounting system, the calculation of

change in carbon stocks for harvested forests overestimates emissions because the carbon in the harvested wood is assumed to be immediately released to the atmosphere. Carbon pools in wood products include wood-in-use (e.g., lumber, furniture, and paper) and wood products that have been discarded in landfills or recycled.

There are two basic approaches that can be used to estimate the quantity of carbon in wood products. The first approach is to track, over time, the decay of materials stored in wood products and account for the emissions in the year in which they occur. If this approach is used, each individual harvest year must be followed by separate annual tracking and reporting of the changes in wood product pools. The second approach is to estimate the quantity of carbon remaining in harvested wood products at 100 years after harvest, and report that quantity in the year of harvest. Regardless of which approach is used, accounting for carbon in wood products begins at the first harvest that occurs after the start year selected by the reporter. It is not necessary to estimate changes in the carbon content of wood products that were harvested in previous years. A technical Appendix to this document includes tables, decay-rate equations and default coefficients that can be applied to inventory estimates, harvest volumes or wood product statistics to estimate carbon stored in wood products at any time after harvest using one of the two basic approaches.

#### 1.I.2.5.5 Approach for Biomass Energy

Biomass energy involves an important cross-sectoral linkage between forestry and the electricity supply sector. Analysis of the carbon flows should account for both changes in carbon sequestration (using the methods described in Section 1.I.2.6) and the effects of substituting biomass energy for fossil-fuel energy. Calculating the release of carbon from the combustion of biomass fuel and the displacement of emissions from fossil fuels is described in the Technical Guidelines for the electricity supply sector.

#### 1.I.2.5.6 Partitioning the Land Base for Calculations

Reporters may have a diverse land base that is affected by different forestry activities, managed at different intensities, or that has a variety of existing data. One of the first steps in preparing entity-wide or sub-entity estimates of carbon fluxes from forests is to organize the underlying data on land conditions into manageable units, referred to here as forest strata. Land should be grouped into forest strata using a logical framework that aggregates similar land units. For example, land could be partitioned by average tree age, forest type, productivity class, and management intensity. In many cases forest strata will be contiguous, although this is not a necessary condition.

In addition to currently having similar characteristics, reporters should expect that land in a given forest strata will be managed similarly in the future. It may be necessary to aggregate or disaggregate land in a particular forest strata in future reports depending on changes in management practices. A small entity may have only one or two forest strata, while larger entities could have land in virtually every age strata for numerous types of forest.

Partitioning allows the use of more than one estimation method, giving the reporting entity some flexibility to reduce overall estimation costs by matching methods to the level of accuracy needed. Use of partitioning does not require defining separate sub-entities because it is part of a single calculation method.

### 1.I.2.6 Basic Estimation Methods

#### 1.I.2.6.1 Look-up Tables

The simplest approach to estimating carbon stock inventories is to use look-up tables that represent average forest conditions for a region, ownership class, forest type, and productivity class. Before using the look-up tables, it is necessary to determine the area of land to be included in the estimate, and characterize that area (i.e., stratify the land area) in a way that is compatible with the estimates in the look-up tables. The average values presented in the look-up tables can then be multiplied by the area estimate to obtain the carbon stock estimate. Although this approach is simple and inexpensive to use, the uncertainty for individual activities or entities may be high relative to other approaches that may be more applicable to the specific circumstances of the activity or entity.

A variety of look-up tables, based on inventories conducted across all U.S. forestlands, is provided in the Appendix to this section. Since these tables represent average conditions over large areas, the actual carbon flows for a specific activity or entity may be different than the estimate developed by using the default carbon factors in the look-up tables. If it is determined that the conditions for an activity or entity are not represented by any of the pre-compiled look-up tables, reporters may choose to generate custom look-up tables or use a different estimation method (models or direct measurement). Entities generating custom tables must follow the guidance on new methods in Part 1, Section 1.A.4.

Data provided in the look-up tables will generally not be appropriate for use by entities reporting on forests outside of the United States unless the conditions of the forest are consistent with climate regions and forest types covered by the tables. In most cases, entities reporting on non-U.S. forest operations should use models or direct measurement to estimate carbon stock changes following the guidance provided in the following sections.

**Example 1. Using look-up tables.** This example demonstrates how to estimate the carbon stock inventory and annual carbon flow for a 200-hectare, 25-year-old stand of highly productive, naturally regenerated pine after harvest in the Southeast. The information needed to estimate both the carbon stock inventory and annual carbon flow is provided in Table 3.I.E1, which includes data from the appendix tables. The data in the table represent the average amount of carbon stored per hectare in various forest carbon pools for two different forest-age classes.

Table 1.I.E1. Average carbon stock on high productivity natural pine, reforestation, Southeast (from a look-up table)

| Stand Age | Living Tree | Standing Dead Tree | Understory | Down Dead Wood | Forest Floor | Total non-soil |
|---|---|---|---|---|---|---|
| | MTC/ha | | | | | |
| 20 | 40.8 | 1.9 | 3.2 | 5.8 | 8.7 | 60.4 |
| 25 | 50.3 | 2.1 | 3.1 | 5.9 | 9.8 | 71.2 |

To estimate the current carbon stock inventory ($I_t$) for a 25-year-old stand, multiply the 200 hectares by a default estimate of 71.2 metric tons of carbon per hectare for this type of forest:

$$I_t = (200) \times (71.2) = 14{,}240 \text{ metric tons.}$$

To estimate the net average annual carbon stock change over 5 years, follow the same process to estimate the total carbon inventory for a 20-year-old stand. In this example,

$$I_{t-5} = (200) \times (60.4) = 12{,}080 \text{ metric tons.}$$

Following the formula developed in section 1.I.2.5.2:

**Net average annual carbon stock change from years 20-25 = (14,240-12,080)/(25-20) = 432 metric tons per year**

The resulting estimate is reported as a net average annual change in carbon stocks of 432 metric tons per year.

### 1.I.2.6.2 Models

A variety of models are available for many different forest conditions and activities. In some cases, models may be more accurate than look-up tables for specific activities or entities, but may require more effort and possibly higher cost. Models useful for estimating quantities of forest carbon may be based on traditional empirical timber production models modified to predict carbon stocks or flows. More recently, models that include the representation of key ecosystem processes such as photosynthesis and respiration are becoming available. Such models may be applied to conditions and treatments beyond those represented in the data used to develop the models, but this should be done cautiously and with appropriate verification to ensure the accuracy of estimates.

Before using a model it is necessary to determine the area of land to be included in the estimate, and characterize that area in a way that is compatible with estimates from the model. To achieve the best results, the selected model should be parameterized for the specific conditions of the land area to which the model is applied. Partitioning of the land area into relatively uniform strata may help in matching and parameterizing a model for a specific application.

In general, models may be useful tools for estimating both entity-wide carbon flows and activity-level accomplishments. If a modeling approach is used, periodic validation of model estimates of carbon stocks with field data is strongly recommended. Models may also be used to update inventories of carbon stocks for annual reporting in the years in between direct measurements made at multi-year intervals.

Models should be evaluated (validated) to be sure they are appropriate for each application. Specific guidance for using and evaluating models is provided in the Appendix. The basic elements of model evaluation are: (1) scientific peer review, (2) quantitative comparison of model results to field observations, and (3) sensitivity analyses.

A user-friendly model developed by the United States Department of Agriculture Forest Service (USFS) called Carbon Online Estimation (COLE) is available via a web interface at http://ncasi.uml.edu/COLE/. COLE provides customized estimates of forest carbon for user-selected areas of the conterminous United States. The model allows users to designate an area of interest, and currently provides area, growing-stock volume, and carbon pool estimates for the conterminous United States. Designating areas that are similar to the area being reported on will ensure that the carbon pool estimates obtained will be more accurate than values obtained from the look-up tables provided in the Appendix.

Entities using models other than the COLE model must follow the guidance on new methods in Chapter 1, Part A, Section A.4 of the Technical Guidelines.

**Example 2. Using models.** This example is similar to Example 1, except that a forest yield model is used to generate estimates for the data table. Just as in Example 1, the data in the table represent the average amount of carbon stored per hectare in various forest carbon pools for two different forest-age classes. However, in this case, the estimates were generated with a modified forest volume yield model. The modified yield model could not estimate carbon in the forest floor, so default values from the appendix tables were used for that column. The modified yield model could not estimate carbon in the understory vegetation, but because that carbon pool is typically very small and has a low rate of change in stands older than about 10 years, it was ignored in the calculations.

Table 1.I.E2. Average carbon stock on high productivity natural pine, reforestation, Southeast (from a modified yield model).

| Stand Age | Living Tree | Standing Dead Tree | Down Dead Wood | Forest Floor | Total non-soil |
|---|---|---|---|---|---|
| | MTC/ha | | | | |
| 20 | 45.1 | 2.5 | 2.3 | 8.7 | 58.4 |
| 25 | 58.3 | 3.2 | 2.9 | 9.8 | 74.2 |

To estimate the current carbon stock inventory ($I_t$) for a 25-year-old stand, multiply the 200 hectares by the model estimate of 74.2 metric tons of carbon per hectare for this type of forest:

$$I_t = (200) \times (74.2) = 14{,}840 \text{ metric tons.}$$

To estimate the net average annual carbon stock change over 5 years, follow the same process to estimate the total carbon inventory for a 20-year-old stand. In this example,

$$I_{t-5} = (200) \times (58.4) = 11{,}680 \text{ metric tons.}$$

Following the formula developed in subsection 1.I.2.5.2:

**Net average annual carbon stock change from years 20-25 = (14,840-11,680)/ (25-20) = 632 metric tons per year**

The resulting estimate is reported as a net average annual change in carbon stocks of 632 metric tons per year.

### 1.I.2.6.3 Direct Measurement

The most accurate way to estimate carbon stocks or flows for an activity or entity is to use direct measurement, which involves developing and implementing a sampling and estimation approach that is appropriate and efficient for the land area being measured. Implementing the direct measurement approach involves the following steps:

- delineate the area (by strata) to be sampled
- determine the number of sample locations required
- design an efficient sample plot layout
- decide exactly which variables to measure
- collect and compile the data
- convert the raw data into estimates
- perform quality assurance and quality control over the monitoring operation

The effort required to perform direct measurement, and thus the cost, is usually higher than using look-up tables or models, although the uncertainty of the resulting estimates should be considerably lower. In many situations, reporters may wish to consult a specialist in forest inventory and monitoring to assist in applying the direct measurement approach. Detailed guidance for using a measurement approach is provided in the Appendix.

**Example 3. Using a measurement approach.** This example is similar to Examples 1 and 2, except that a direct measurement approach is used to generate estimates for the data table. Just as in Examples 1 and 2, the data in the table represent the average amount of carbon stored per hectare in various forest carbon pools for two different forest-age classes. However, the estimates were generated with a forest inventory system that was established at the time the stand was 20 years old. Using the approach described in the appendix, it was determined that 25 sample plots were needed to estimate carbon stocks with an accuracy of plus or minus 10 percent at the 95 percent confidence level. Those same plots were re-measured when the stand was 25 years old. It was determined that carbon in understory vegetation was negligible, so this variable was not measured. It was also determined that soil carbon was not likely to change significantly in 5 years, so it was not measured.

Table 1.I.E3. Average carbon stock on high productivity natural pine, reforestation, Southeast (from direct measurement).

| Stand Age | Living Tree | Standing Dead Tree | Down Dead Wood | Forest Floor | Total non-soil |
|---|---|---|---|---|---|
| | MTC/ha | | | | |
| 20 | 39.2 | 1.1 | 3.4 | 7.4 | 51.1 |
| 25 | 57.4 | 1.5 | 3.9 | 8.0 | 70.8 |

To estimate the current carbon stock inventory ($I_t$) for the 25-year-old stand, multiply the 200 hectares by the measured estimate of 70.8 metric tons of carbon per hectare:

$$I_t = (200) \times (70.8) = 14{,}160 \text{ metric tons}$$

To estimate the net average annual carbon stock change over 5 years, follow the same process to estimate the total carbon inventory for the 20-year-old stand and compare the estimates. In this example,

$$I_{t-5} = (200) \times (51.1) = 10{,}220 \text{ metric tons}$$

Following the formula developed in section 1.I.2.5.2:

**Net average annual carbon stock change from years 20-25 = (14,160-10,220)/ (25-20) = 788 metric tons per year**

The resulting estimate is reported as a net average annual change in carbon stocks of 788 metric tons per year.

### 1.I.2.6.4 Rating System for Estimates

Part A of this Chapter, "Introduction," describes a rating system for estimation methods. The rating system for forestry sector approaches follows the logic in Table 1.I.3, as long as the technical guidelines in this section are closely followed.

**Table 1.I.3 Forestry Sector Rating System**

| Forest Ecosystem Carbon Pools | Harvested Wood Products Pool | Rating |
|---|---|---|
| Estimates from look-up tables that match specific site conditions and management practices, as documented using independent data or information.<br><br>Use of the USFS COLE model or an approved[1] model, validated with data specific to the site conditions and management practices.<br><br>Sampling with quantified accuracy | Use of an approved[1] model validated with data specific to the product mix of the entity | A |
| Estimates in look-up tables adapted to specific site conditions and management practices.<br><br>Use of an approved[1] model that is parameterized specifically for site conditions and management practices.<br><br>Use of the Forest Service COLE model | Use of specific data on harvest and product mix and default decay factors provided in section 4 of the Appendix | B |
| Typical application of regional look-up tables that generally match the site conditions and management practices.<br><br>Use of an approved[1] model that generally matches site conditions and management practices. | Use of aggregate data on harvest and default decay factors provided in section 4 of the Appendix | C |
| Use of look-up tables for site conditions and management practices that are not represented by the tables. | | D |

[1]Reporters may obtain DOE approval for the use of methods that are not provided in the guidelines. Information on approval of new methods is provided in Chapter 1, Part A, Section A.4 of the Technical Guidelines. Reporters may also certify that in using a model, they have followed the guidelines in the modeling Appendix to this document.

The accuracy of estimates from the look-up tables will depend on how well the estimates in the tables represent the specific conditions of the land area or strata for which an estimate is required. The more the estimation method approximates the actual site conditions and management practices, the greater the accuracy and, consequently, the accuracy rating. Thus, while applying a regional estimate from a look-up table to a specific tract of land would be rated "C," modifying the information contained in look-up tables to match site-specific characteristics and management conditions would be rated "B." Estimates derived from look-up tables can be rated "A" if independent data and information are used to document that the look up tables match site conditions and management practices.

As described in subsection 1.I.2.6.2, the COLE model may be used to generate estimates that are rated "B." The rating for other models will depend on how well the model represents the specific conditions of the land area. A model that is developed specifically for a reporter's land conditions and management practices may achieve a higher rating, especially if the model is validated. Similarly, use of an inappropriate model for the land characteristics and practices may result in a lower rating. Entities using models other than the COLE model must use the guidance on new methods in Chapter 1, Part A, Section A.4 of the Technical Guidelines, or may follow the guidelines in the modeling Appendix to this section.

The direct measurement approach allows reporters to develop an estimate of carbon stocks and flows with known, quantified accuracy. Such an estimate would be rated "A."

**Example 4. Rating for land partitioning and use of different estimation methods.** A reporting entity manages 500 ha of land, which is partitioned into three strata as shown in Table 1.I.E4. A different method was used to estimate the stock of carbon (C) for each of the strata, with the estimates summed to the total for the whole land area.

Table 1.I.E4. Inventories of carbon stocks for an entity, excluding soil carbon, 2000 and 2005

| Land type | Estimation method | Land area (hectares) | Average C stock 2000 (MTC/ha) | Total C stock 2000 (MTC/ha) | Average C stock 2005 (MTC/ha) | Total C stock 2005 (MTC/ha) |
|---|---|---|---|---|---|---|
| Pine plantation | Model | 200 | 58.4 | 11680 | 74.2 | 14840 |
| Stream buffer (lowland hwd) | Default tables | 50 | 146.0 | 7300 | 153.0 | 7650 |
| Mixed hardwoods | Measurement | 250 | 117.3 | 29325 | 127.8 | 31950 |
| Total | | 500 | | 48305 | | 54440 |

Using the formulas for estimating changes in carbon stocks, the entity estimates an average annual change of 1,227 MTC.

Table 1.I.E5 shows how a weighted average rating can be computed for this example, assuming that the estimation methods are developed and rated according to the guidance provided in this document,

**Table 1.I.E5. Calculation of weighted average rating**

| Estimation method | Rating | Total C stock 2005 (MTC/ha) | Rate-weighted C stock (rating x total C stock) | Summary score |
|---|---|---|---|---|
| Model | B | 14,840 | 44,520 | |
| Default tables | C | 7,650 | 15,300 | |
| Measurement | A | 31,950 | 127,800 | |
| Total | | 54,440 | 187,620 | 3.4 |

The summary score of 3.4 is calculated by dividing the total of column 4 by the total of column 3. This score is between an "A" and a "B" on the rating scale.

## 1.I.3 Sector-Specific Issues for Forestry

This subsection addresses a number of issues specific to activity and entity-wide reporting in the forestry sector. The text provides general guidance for reporters to use to develop estimates of the net effects of forestry activities. It may not be necessary to account for all these issues for a specific forestry activity undertaken by a specific entity, but each issue should be considered by reporters before developing estimates of net carbon flows.

### 1.I.3.1 Exclusions

The General Guidelines allow reporters to exclude certain emissions that are comparatively small as *de minimis*—those up to 3 percent of the total emissions in carbon dioxide equivalent. The General Guidelines also permit categorical exclusions of non-anthropogenic emissions.

These allowable exclusions should be considered when addressing issues such as natural disturbance, which greenhouse gases to report and carbon pools to measure, and which estimation approach to use for different land areas.

### 1.I.3.2 Land-Use Change

Land-use change is a change in land classification among these categories: forest land, cropland, grassland, and developed land (including urban land). Reporters should refer to the glossary for definitions of these land classes. Some forestry activities are by definition a change in land use (e.g., afforestation).

Land-use change may affect all or part of the land area of an entity or activity. Since the estimation methods for land-use change may be different than the estimation methods for other land, determining the area where land-use change has occurred is important.

When estimating changes in carbon stocks from land-use change, reporters must be careful to use methods that are compatible with both forest and non-forest land uses. For example, soil carbon should be defined to a consistent depth, so that when comparing the estimated stock of soil carbon of two different land uses, any differences reflect the change in the land use, and not the use of two different estimation methods.

To estimate the change in carbon stocks for afforestation, reporters may use any of the methods described in Section 1.I.2.6. Section 1.I.4.1 describes afforestation activity and discusses some of the issues that should be considered.

Deforestation is not included among the list of forestry activities because it causes a reduction in forest carbon stocks. Nonetheless, an entity should estimate the effects of deforestation on carbon stocks as part of their comprehensive greenhouse gas inventory. Of the methods described in Section 1.I.2.6, measurement and modeling can be appropriately applied to estimate changes in carbon stocks from deforestation. To use the look-up tables, additional assumptions are required. The look-up tables provide estimates of pre-harvest carbon stocks for each

ecosystem component; however, the individual components should be treated according to the following table of assumptions:

### Table 1.I.4. Assumptions

| Ecosystem component | Deforestation assumption |
|---|---|
| Trees | 100 percent loss |
| Understory vegetation | 100 percent loss |
| Standing dead wood | 100 percent loss |
| Down dead wood | 100 percent loss |
| Forest floor | 100 percent loss |
| Soil | 10% loss each 5 years for 15 years |

Wood products from deforestation should be counted and estimated using the methods described in the harvested wood products Appendix.

When incidental lands are converted to developed uses, the methods for deforestation described above should be followed using the forestry look-up tables that most closely match climate conditions and tree species composition of the land in question. After conversion, carbon stocks on developed lands can be assumed to not change. If trees are planted on developed lands, entities may follow the guidance on Urban Forestry below to estimate carbon stock changes in urban trees.

### 1.I.3.3 Permanence

Permanence refers to the longevity of a carbon pool and the stability of its stocks. Carbon that is sequestered in soils, vegetation, or wood products is not necessarily permanently removed from the atmosphere. A different landowner or change in management objectives may change forestry activities originally intended for one purpose. Landowners may change their practices causing the release of stored carbon, or natural disturbances (discussed in the next subsection) may cause the loss of stored carbon to the atmosphere. This subsection addresses the issue of the longevity of carbon pools and associated reporting considerations.

As a general rule, all changes in carbon stocks should be accounted for by periodic inventory and reporting. Such changes in carbon stocks are a response to the logical progression of events that affect an activity or entity over time and should be monitored accordingly. Calculations should include effects on all carbon pools, both positive and negative, so that reporters can record the net effect on carbon flow. Thus, for most cases, permanence is not an issue because the periodic inventory and annual reports should reflect changes in net carbon flows, whether positive or negative, when they occur.

The permissible exclusion of the effects of natural disturbances represents a case where the reporter may choose to explicitly account for a loss of carbon stocks, as discussed below.

### 1.I.3.4 Natural Disturbances

Carbon in forests may be lost to natural causes such as an insect epidemic, drought, or wildfire. Those events may happen at any time during the duration of reporting and may affect all or only a portion of the land area within activity or entity boundaries. Natural disturbances may be rare events, in which case the effects on estimated carbon flows may be small when averaged over large forested areas or long periods of time.

The General Guidelines provide that natural disturbances may be excluded from calculations to determine registered reductions, thus requiring reporters to make a separate estimate of the effect of natural disturbances on all carbon pools. If the effects of natural disturbances can be separated from other causes of changes in carbon pools, the estimated changes in carbon stocks resulting from natural disturbances should not be deducted from the annual estimate for the entity. Likewise, the entity should not claim increases in carbon stocks as a result of the regrowth of forests after natural disturbance until the carbon stocks return to pre-disturbance levels. To keep track of changes after disturbance, the entity should identify disturbed land as a separate stratum in the estimation process (see subsection 1.I.2.5.6 on partitioning the land base).

Catastrophic disturbances such as wind storms may cause obvious and easily estimated changes in carbon stocks, while in other cases, such as a one-year period of insect defoliation, it may be difficult after a few years to separate the effects of the natural disturbance from other factors. In some cases, the inventory of base year/period carbon stocks may take into account average levels of natural disturbance, provided that the inventory for the base year/period is an accurate reflection of typical conditions and that natural disturbances occur relatively frequently. The estimated carbon stocks for both the reporting year and base year/period will thus include an average or typical level of natural disturbances, and there is no need to separately account for them.

### 1.I.3.5 Sustainably Managed Forests

Forest certification systems require landowners to harvest at sustainable rates, thus preventing long-term declines in carbon stocks. Carbon stocks in sustainably managed forests will fluctuate in response to natural disturbances, harvest schedules, changes in markets, and changes in technology. Nevertheless, it is valid to conclude that significant long-term declines in forest carbon stocks are unlikely to occur in sustainably managed forests when considering all forests carbon pools such as soil, litter, biomass and long-lived products.

Entities may assume there is neither an increase nor decrease in carbon stocks on certified sustainably managed forests. The entity can claim that changes in sequestration for forests managed under certified sustainable management systems are *de minimis*. Third-party certification systems, such as the following, should be used to determine that lands are sustainably managed:

1. The Sustainable Forestry Initiative (SFI)
2. Forest Stewardship Council
3. The American Tree Farm System

4. Green Tag Forestry, National Woodlands Owners Association

While there are some differences among the major certification programs in their goals and technical details, all of the programs set high standards and have rigorous third-party audit protocols.

All or part of an entities' forest land can be certified as being managed sustainably. Entities may choose to include actual estimates of changes in carbon stocks on some of their lands, rather than relying on the assumption of *de minimis* changes.

If an entity chooses to use the assumption that sustainable forest lands are *de minimis* on part of their lands and report actual changes in carbon stocks on other lands, the entity should document that the certification of sustainability applies to the lands being considered *de minimis*, independent of the entities' other lands. Once an entity classifies a portion or all of its lands as sustainably managed forest, it may not report carbon sequestration on the lands categorized as sustainably managed in future reports.

### 1.I.3.6 Incidental Lands

Incidental lands are entity landholdings that are a minor component of an entity's operations and are not actively managed for the production of goods and services, including: transmission, pipeline, or transportation right of ways that are not managed for timber production; land surrounding commercial enterprises or facilities; and land where carbon stock changes are fundamentally determined by natural factors. Entities have the option to use the methods in these guidelines (e.g., look-up tables, models, or direct measurement) to estimate changes in terrestrial carbon stocks on incidental lands or to report that carbon stocks on incidental lands are not changing. Regardless of which option is chosen, entities must report on the area and type of incidental lands owned. If incidental lands are converted to developed uses, the impact of the development on the carbon stocks must be accounted for in the entity inventory following the guidance in Section 1.I.3.2 for land use changes.

## 1.I.4 Forestry Activities

This section describes the procedures for estimating changes in carbon stocks for seven general classes of forestry activities. Small entities can report and register activity-based carbon emissions and sequestration. Some larger entities may find it useful to organize their entity-wide inventories by forestry activities. Each activity class has unique characteristics that should be considered in making estimates and performing activity or entity analysis. The activities included are broad but not comprehensive, and are described here to provide general guidance on how to apply the estimation approaches contained in this section.

### 1.I.4.1 Afforestation, Mine Land Reclamation, and Forest Restoration

Forests may be established to replace another land use such as cropland or pastureland, may be used to reclaim abandoned mine lands, or may be established as part of a land restoration activity.

***Afforestation*** is a change in land use that may greatly alter carbon stocks on a site. Tree planting activities have the benefit of producing large gains in carbon stocks (at least in the initial decades of tree growth) because they usually replace land uses that have a relatively constant stock of carbon from year to year.

Planting trees on nonforested land has been widely promoted as an effective tool for increasing carbon sinks globally; thus tree planting has received the most attention in the analysis of forestry's effects on global carbon cycles. There are numerous sources of information on the carbon sequestered and stored by forests after afforestation, and reference examples can be found in the studies cited in the Appendix. Published studies indicate it is critical to distinguish among species types, the productivity class of the forest site, and the intensity of management efforts.

***Mine land reclamation*** is a special case of afforestation. For many areas of abandoned or unreclaimed mined land, some vegetation may be established but it often accumulates carbon at a very slow rate due to slow plant growth on the highly disturbed and compacted soils. Mine land soils are depleted of carbon, therefore the potential to increase carbon in those soils may be much higher than for any other forestry activity. Reporters should be particularly attentive to estimating the changes in soil carbon on reclaimed mine land.

***Forest restoration*** can often be considered a special case of afforestation with regards to estimating changes in carbon stocks. The goal of the restoration activity is to return the land to its original structure and species composition. If the land is in nonforest use prior to initiation of the restoration activity, the activity meets the definition of afforestation. If the land is in forest use prior to the initiation of the restoration activity, the activity meets the definition of forest management and reporters should refer to Section 1.I.4.3.

The major effect of afforestation is to increase carbon stocks by the growing trees and the developing forest ecosystem. Other factors to consider include biological and energy-related emissions during the planting process, and emissions resulting from the use of fertilizers.

The rate of increase in carbon stocks depends upon several factors, including tree species, geographic area, soil type, precipitation, slope, and aspect. The annual change in carbon stocks must be determined for each reporting year, and can be accomplished on the basis of periodic field measurements, computer models, or look-up tables provided in this document.

### 1.I.4.2 Agroforestry

Agroforestry combines agriculture (crops and/or animals) and silviculture on the same tract of land. Because it emphasizes the use of woody and perennial crops and biological fertilizers, it may provide agricultural products with less intensive energy input and sequester more carbon than traditional agriculture. Agroforestry systems can be quite complex, addressing not only production of grains and fruits for human consumption, but also the production of feed and forage for livestock, the production of wood fuel, fiber and building materials, and the restoration of degraded land.

The change in carbon stock can be estimated using the forest inventory methods described in this section. However, agroforestry can also affect energy-related emissions from farm and irrigation equipment, biological emissions from soil disturbance and livestock, emissions related to the production and use of fertilizer, and emissions related to fuel wood use. Reporters should consult the Technical Guidelines for other sectors such as agriculture and energy to estimate those effects.

Agroforestry activities are made up of a wide range of interdependent actions. While substantial research has been conducted to evaluate various agroforestry activities, it is not clear to what extent the results of the research can be generalized to assist in evaluating other activities. In the face of the difficulties associated with estimating activity effects, a more credible report may result if the analysis is limited to the most certain of the effects, such as carbon sequestration by trees and soils.

### 1.I.4.3 Forest Management

It may be possible to modify the management regimes of existing forests to increase their carbon stocks. Management decisions regarding objectives can be made at any and all stages in a rotation. Activities may be applied either during the period of forest growth (intermediate forest treatments) or at the time of harvest and regeneration.

Intermediate treatments include, but are not limited to, the following:

- Species composition control
- Pre-commercial thin
- Commercial thin
- Management of hazardous fuels
- Firewood harvests
- Fertilization
- Prescribed fire
- Changing the rotation length

These activities may increase (or decrease) carbon stocks, although the effects of various treatments tend to be highly site-specific. As a consequence, it may not be possible to use generalized methods for site-specific estimation, and reporters will need to develop specific

methods and have them certified for use in their report. Entities developing new methods must follow the guidance provided in Chapter 1, Part A, Section A.4 of the Technical Guidelines.

Increases in carbon stocks may also be possible by altering the processes used to harvest and regenerate the forest site. Logging techniques and utilization standards influence the amount of residual material left in the forest to decompose and the survivability of residual trees. In addition, techniques used to prepare and encourage forest regeneration, such as prescribed burning, can release greenhouse gases. Site preparation techniques include the following:

- Site preparation burning
- Mechanical site preparation
- Chemical site preparation.

Forest management may also include a decision to preserve a forest that has previously been treated in some other way. Forest preservation may involve protecting existing forests from harvest or conversion to other land use or uses. Preserved forests will continue to be affected by natural disturbances. Although the net change in carbon stocks from preservation is expected to be positive, the result depends upon the effects of natural disturbance on all of the forest carbon pools. An entity may choose to report and register the preservation of existing terrestrial carbon stocks as a forest management practice if restrictions are placed on the land to ensure that human-caused releases of carbon do not occur in the future. Options include permanent conservation easements and deed restrictions.

Changes in carbon stocks for managed forests are estimated using the approach described in Section 1.I.2. Reporters may choose among the standard estimation methods: periodic field measurements, computer models, or look-up tables Estimating changes in carbon stocks in response to specific forest management practices using models or look-up tables is not possible in all cases, because currently there is little quantitative information available about how specific forest management activities affect all ecosystem carbon pools. Periodic direct measurement may currently provide the only viable approach, although research on the effects of forest management on the carbon cycle is progressing and appropriate models and lookup tables may become available in the future. Wood products may be part of the forest management regime. How to treat wood products as part of forest management is addressed separately in Section 1.I.4.6.

### 1.I.4.4 Short-Rotation Biomass Energy Plantations

For estimating changes in carbon stocks, biomass energy plantations occupy an intermediate position between forestry and annual agriculture. With woody biomass crops, harvesting occurs approximately every 5 to 12 years, and regeneration is often accomplished by coppice methods that rely on the regrowth of new stands from the root stock of the harvested stand. Regeneration may also involve the planting of genetically improved planting stock. Reporters should be careful to consider the effects of biomass energy plantations on all of the forest ecosystem carbon pools.

The principal effect of a biomass energy activity is to displace fossil energy with biomass energy, thereby reducing fossil-fuel carbon emissions to the atmosphere. Reporters should also account for fossil-fuel emissions from the harvesting and transportation of the biomass fuel. For guidance in making estimates, reporters should consult the Technical Guidelines for the electricity supply sector regarding emissions from biomass fuels and the displaced fossil fuels.

### 1.I.4.6 Wood Products

There are several kinds of activities that result in the production of wood products, which may be part of a forest management regime or result from manufacturing processes. Wood may also be burned for energy as a substitute for use of fossil fuels, and wood products may be substituted for other products. This subsection addresses only the production of wood products as part of a forest management regime. Use of wood for energy is addressed in Section 1.I.4.4 and in Technical Guidelines for the energy sector. Substitution of manufactured products is covered by the Technical Guidelines for the manufacturing sector.

Several of the activities discussed in this subsection could involve the harvest of timber or pulpwood for use in wood products. Studies have indicated that the carbon contained in harvested trees follows several different paths after harvest, with some remaining in wood products for only a short time (1 to 5 years), but a significant amount remaining for decades before returning to the atmosphere. Some of the carbon may be recycled or stored in landfills after the initial wood-product use is discontinued.

Tracking carbon in wood products requires a different approach than tracking carbon in forest ecosystems. Acceptable approaches are described in subsection 1.I.2.5.4.

### 1.I.4.7 Urban Forestry

Urban forestry activities can have two principal effects on greenhouse gas emissions and changes in carbon stocks. One is increased carbon sequestration through tree growth. As with all forestry activities, urban trees sequester carbon in above and belowground components, and may also contribute to increasing carbon stocks in soils. Urban trees, however, may require maintenance efforts such as trimming and leaf collection that need to be factored into the estimates.

The other principal effect is the avoidance of greenhouse gas emissions through energy conservation. Simulation models indicate that strategically located trees may provide two kinds of effects in this regard. One is through increased shading during peak cooling periods (deciduous trees conveniently cast a great deal of shade during the growing season and much less during the winter). The other effect results from establishment of a windbreak (often provided by conifers) that reduces fuel use during winter heating months. The location of the trees relative to the targeted building is a critical factor.

The estimation of carbon stocks and changes in carbon stocks is directly analogous to that described for forest management activities—that is, changes in carbon stocks by trees is measured as the net increase relative to the previous land use (for example, lawn). The estimates

should account for both above- and below-ground components and all relevant tree maintenance activities.

The guidance provided in this document is most appropriate for land areas that meet the definition of forest. In contrast, urban trees are often managed as single trees rather than forest trees, and so the methods must be adapted. Although the estimation approach is the same for urban and rural forests, the specific data and models are likely to be different. In general, the guidance provided for measuring changes in carbon stocks can be used for urban street trees, but sampling methods should be carefully reviewed and possibly revised for efficient application in an urban setting. There are several models available for estimating the changes in carbon stocks for urban trees. Reporters should follow the modeling guidelines to evaluate whether a specific model is appropriate for use. The current forestry guidelines do not provide look-up tables for urban trees.

Estimating reductions in greenhouse gas emissions through energy conservation can be a complicated endeavor because many factors are variable over the life of the activity. One source of variation is climate—the temperature regime differs from year to year. Another source is additional modifications in the building that may influence energy consumption (and the energy-saving contribution of trees). Entities interested in reporting greenhouse gases and registering reductions associated with the energy savings activities should refer to those sections of the Technical Guidelines pertaining to the residential and commercial buildings sector.

## Technical Guidelines for Voluntary Reporting of Greenhouse Gases Program

## Chapter 2, Emission Reductions

Outline


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- 2.4.5. Action-Specific Calculation Methods
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2.5. Determining Registered Emission Reductions

2.6. Revising Previously Accepted Reports of Emission Reductions

# 2.1 Introduction

This Chapter, Emission Reductions, provides draft Technical Guidelines and explanatory materials that are directly relevant to the emission reductions guidelines contained in Section 300.8 of the revised General Guidelines. An excerpt of Section 300.8 is provided below, followed by the Emission Reduction Guidelines relevant to this section and explanatory information and examples as needed.

The Energy Information Administration (EIA) will develop the forms and instructions necessary for reporters to participate in the program. Those forms and instructions will be designed to implement both the General Guidelines and the Technical Guidelines.

# 2.2 Calculating Emission Reductions

## 2.2.1 Section 300.8 of the General Guidelines

*Excerpt from the General Guidelines, section 300.8, Calculating emission reductions:*

*(a) Choosing appropriate emission reduction calculation methods.*

*(1) An entity must choose the method or methods it will use to calculate emission reductions from the list provided in paragraph (h) of this section. Each of the calculation methods has special characteristics that make it applicable to only certain types of emissions and activities. An entity should select the appropriate calculation method based on several factors, including:*

*(i) How the entity's subentities are defined;*

*(ii) How the reporter will gather and report emissions data; and*

*(iii) The availability of other types of data that might be needed, such as production or output data.*

*(2) For some entities, a single calculation method will be sufficient, but many entities may need to apply more than one method because discrete components of the entity require different calculation methods. In such a case, the entity will need to select a method for each subentity (or discrete component of the entity with identifiable emission or reductions). The emissions and output measure (generally a physical measure) of each subentity must be clearly distinguished and reported separately. Guidance on the selection and specification of calculation methods is provided in Chapter 2 of the Technical Guidelines (incorporated by reference, see §300.13).*

*(b) Identifying subentities for calculating reductions. If more than one calculation method is to be used, an entity must specify the portion of the entity (the subentity) to which each method will be applied. Each subentity must be clearly identified. From time to time, it may be necessary to modify existing or create new subentities. The entity must provide to EIA a full description of such changes, together with an explanation of why they were required.*

*(c) Choosing a base period for calculating reductions. In general, the base period used in calculating emission reductions is the single year or up to four-year period average immediately preceding the first year of calculated emission reductions.*

*(d) Establishing base values. To calculate emission reductions, an entity must establish a base value against which to compare reporting year performance. The minimum requirements for base values for each type of calculation method are specified in Chapter 2 of the Technical Guidelines (incorporated by reference, see §300.13). In most cases, an historic base value, derived from emissions or other data gathered during the base period, is the minimum requirement specified. Entities may, however, choose to establish base values that are more stringent than the base values derived from the methods specified in Chapter 2 of the Technical Guidelines as long as their report indicates the rationale for the alternative base value and demonstrates that it would result in a smaller quantity of emission reductions.*

*(e) Emission reduction and subentity statements. For each subentity, an entity must submit to EIA the following information:*

*(1) An identification and description of the method used to calculate emission reductions, including:*

*(i) The type of calculation method;*

*(ii) The measure of output used (if any); and*

*(iii) The method-specific base period for which any required base value will be calculated.*

*(2) The base period used in calculating reductions. When an entity starts to report, the base period used in calculating reductions must end in the start year. However, over time the reporting entity may find it necessary to revise or establish new base periods and base values in response to significant changes in processes or output of the subentity.*

*(3) A description of the subentity and its primary economic activity or activities, such as electricity generation, product manufacturing, service provider, freight transport, or household operation; and*

*(4) A description of the emission sources or sinks covered, such as fossil fuel power plants, manufacturing facilities, commercial office buildings or heavy-duty vehicles.*

*(f) Changes in calculation methods, base periods and base values. When significant changes occur in the composition or output of reporting entities, a reporting entity may need to change previously specified calculation methods, base periods or base values. A reporting entity should make such changes only if necessary and it should fully document the reasons for any changes. The Technical Guidelines (incorporated by reference, see §300.13) describe when such changes should be made and what information on such changes must be provided to DOE. In general, such changes should not result in any alterations to previously reported or registered emission reductions. A reporting entity may alter previously reported or registered emission reductions only if necessary to correct significant errors.*

*(g) Continuous reporting. To ensure that the summation of entity annual reports accurately represents net, multi-year emission reductions, an entity must submit a report every year, beginning with the first reduction year. An entity may use a specific base period to determine emission reductions in a given future year only if the entity has submitted qualified reports for each intervening year. If an interruption occurs in the annual reports of an entity, the entity must subsequently report on all missing years prior to qualifying for the registration of additional emission reductions.*

*(h) Calculation methods. An entity must calculate any change in emissions, avoided emissions or sequestration using one or more of the methods described in this paragraph and in the Technical Guidelines (incorporated by reference, see §300.13).*

*(1) Changes in emissions intensity. An entity may use emissions intensity as a basis for determining emission reductions as long as the entity selects a measure of output that is:*

*(i) A reasonable indicator of the output produced by the entity;*

*(ii) A reliable indicator of changes in the entity's activities;*

*(iii) Related to emissions levels; and*

*(iv) Any appropriate adjustments for acquisitions, divestitures, insourcing, outsourcing, or changes in products have been made, as described in the Technical Guidelines (incorporated by reference, see §300.13).*

*(2) Changes in absolute emissions. An entity may use changes in the absolute (actual) emissions (direct and/or indirect) as a basis for determining net emission reductions as long as the entity makes only those adjustments required by the Technical Guidelines (incorporated by reference, see §300.13). An entity intending to register emission reductions may use this method only if the entity demonstrates in its report that any reductions derived from such changes were not achieved as a result of reductions in the output of the entity, and certifies that emission reductions are not the result of major shifts in the types of products or services produced. Entities may report, but not register, such reductions even if the output associated with such emissions is declining.*

*(3) Changes in carbon storage (for actions within entity boundaries). An entity may use changes in carbon storage as a basis for determining net emission reductions as long as the entity uses estimation and measurement methods that comply with the Technical Guidelines (incorporated by reference, see §300.13), and has included an assessment of the net changes in all sinks in its inventory.*

*(4) Changes in avoided emissions (for actions within entity boundaries). An entity may use changes in avoided emissions to determine its emission reductions. Avoided emissions eligible to be included in the calculation of net emission reductions that qualify for registration include those associated with the sale of electricity, steam, hot water or chilled water generated from non-emitting or low-emitting sources as a basis for determining net emission reductions as long as:*

*(i) The measurement and calculation methods used comply with the Technical Guidelines (incorporated by reference, see §300.13);*

*(ii) The entity certifies that any increased sales were not attributable to the acquisition of a generating facility that had been previously operated, unless the entity's base period includes generation values from the acquired facility's operation prior to its acquisition; and*

*(iii) Generators of distributed energy that have net emissions in their base period and intend to report reductions resulting from changes in eligible avoided emissions, use a method specified in the Technical Guidelines (incorporated by reference, see §300.13) that integrates the calculation of reductions resulting from both changes in emissions intensity and changes in avoided emissions.*

*(5) Action-specific emission reductions (for actions within entity boundaries). A number of source- or situation-specific methods are provided in the Technical Guidelines and these methods must be used to assess the annual changes in emissions for the specific sources or situation addressed by these methods. In addition, a generic action-specific method is identified in the Technical Guidelines. An entity intending to register reductions may use the generic action-specific approach only if it is not possible to measure accurately emission changes by using one of the methods identified in paragraphs (h)(1) through (h)(4) of this section. Entities that intend to register reductions and that use the generic action-specific approach must explain why it is not possible to use any of these other methods. An entity not intending to register reductions may use the generic action-specific method to determine emission reductions, as long as the entity demonstrates that the estimate is based on analysis that:*

*(i) Uses output, utilization and other factors that are consistent, to the maximum extent practicable, with the action's actual performance in the year for which reductions are being reported;*

*(ii) Excludes any emission reductions that might have resulted from reduced output or were caused by actions likely to be associated with increases in emissions elsewhere within the entity's operations; and*

*(iii) Uses methods that are in compliance with the Technical Guidelines (incorporated by reference, see §300.13).*

*(i) Summary description of actions taken to reduce emissions. Each reported emission reduction must be accompanied by an identification of the types of actions that were the likely cause of the reductions achieved. Entities are also encouraged to include in their reports information on the benefits and costs of the actions taken to reduce greenhouse gas emissions, such as the expected rates of return, life cycle costs or benefit to cost ratios, using appropriate discount rates.*

*(j) Emission reductions associated with plant closings, voluntary actions and government (including non-U.S. regulatory regimes) requirements.*

*(1) Each report of emission reductions must indicate whether the reported emission reductions were the result, in whole or in part, of plant closings, voluntary actions, or government requirements. EIA will presume that reductions that were not the result of plant closings or government requirements are the result of voluntary actions.*

*(2) If emission reductions were, in whole or in part, the direct result of plant closings that caused a decline in output, the report must identify the reductions as such; these reductions do not qualify for registration. EIA will presume that reductions calculated using the emissions intensity method do not result from a decline in output.*

*(3) If the reductions were associated, in whole or part, with U.S. or non-U.S. government requirements, the report should identify the government requirement involved and the effect these requirements had on the reported emission reductions. If, as a result of the reduction, a non-U.S. government issued to the reporting entity a credit or other financial benefit or regulatory relief, the report should identify the government requirement involved and describe the specific form of benefit or relief provided.*

*(k) Determining the entity responsible for emission reductions. The entity that EIA will presume to be responsible for emission reduction, avoided emission or sequestered carbon is the entity with financial control of the facility, land or vehicle which generated the reported emissions, generated the energy that was sold so as to avoid other emissions, or was the place where the sequestration action occurred. If control is shared, reporting of the associated emission reductions should be determined by agreement between the entities involved so as to avoid double-counting; this agreement must be reflected in the entity statement and in any report of emission reductions. EIA will presume that an entity is not responsible for any emission reductions associated with a facility, property or vehicle excluded from its entity statement.*

### 2.2.2 Choosing Appropriate Emission Reduction Calculation Methods

The enhanced reporting program emphasizes entity-wide assessments of emission reductions rather than those resulting from discrete projects or other actions affecting only part of an entity's total emissions. Because many reporting entities are likely to encompass a variety of operations (e.g., manufacturing, offices, warehouses, leased fleets, land management), the Guidelines provide considerable flexibility in the selection and application of specific methods used to calculate emission reductions. For example, a manufacturing company may choose to use emissions-intensity methods to calculate reductions, but may produce different products that are unable to be measured by a single fungible unit such as tons. Such a company may therefore need to divide its operations into subentities to facilitate the assessment and reporting of greenhouse gas emission reductions from its various lines of business.

Segmenting the entity into subentities provides reporters the flexibility to use alternative approaches in calculating changes in emissions. For example, it may be desirable to assess the emission reductions associated with some business lines using changes in absolute emissions (if output is flat or increasing), and in others by using one or more intensity metrics. Large emitters seeking to register emission reductions should attempt to assess all their changes in emissions using the fewest number of methods feasible, but may use as many methods as necessary.

Before beginning to report, an entity must select the method or methods it will use to calculate emission reductions. This selection process will determine the definition of the entity's subentities, how it will gather and report emissions data, and what other types of data - such as product production or other forms of output - will have to be gathered. If two or more calculation

methods are selected, the entity must define distinct subentities, one for each method chosen. The emissions and usually the physical or economic measure of the output of each subentity must be clearly distinguished and reported separately.

The five basic calculation methods identified in the revised General Guidelines are designed as a group to enable entities to calculate the emission reductions associated with virtually any type of emission source and activity. No single methodology could achieve this objective on its own. Each methodology has special attributes that make it appropriate for use in some situations but not in others, and each encompasses a range of specific calculation methods or formulas that may make them uniquely applicable to specific entities or subentities. While some entities may be able to use one of the five methods to assess all their year-to-year changes in emissions or carbon sequestration, it is more likely that entities will need to use multiple methods to complete an entity-wide assessment.

The applicability of each of the five methods is discussed in the following five subsections. Most large emitters seeking to register emission reductions are likely to choose either emissions intensity or absolute emissions as their primary method of calculating emission reductions. Electricity generators and other producers of energy that report emissions associated with distributed energy during their Base Period must use an integrated method (described in subsection 2.4.6) that combines the emissions intensity and avoided emissions methods, or use the absolute-emissions method (specified in subsection 2.4.2 of this Chapter). Entities that generate and distribute energy that report no emissions associated with such distribution of energy in their Base Period should use just the avoided emissions method (described in subsection 2.4.4).

#### 2.2.2.1 Changes in Emissions Intensity

Entities are encouraged to calculate reductions using emissions-intensity methods when feasible. Using emissions-intensity methods is usually feasible when the following are applicable:

- There is a clear physical measure of the output associated with, or the service provided by, the emissions.
- The same measure of output is likely to be used for at least several years (that is, the basic product being produced, the output metric, is not likely to change substantially in the near future).
- It is not likely that significant elements of the covered process will be outsourced (or “in-sourced”) in the near future.

A single measure of output and emissions intensity might, in some cases, be able to account for all of an entity's emissions, including both those associated directly with the entity's production process and those other emissions associated with providing managerial or logistical support to the production process. It is likely, however, that many entities will need more than one measure of output and emissions intensity to complete a comprehensive assessment of their annual changes in emissions. See subsection 2.4.1 for guidelines on applying this method.

#### 2.2.2.2 Changes in Absolute Emissions

Any entity may use changes in the quantity of their absolute emissions (for the entity as a whole or a specific subentity) to determine emission reductions to be reported to EIA. However, entities that intend to register their reductions may use this method only *if* they can demonstrate that the output associated with covered emissions did not decline from the identified base period to the reporting year. Entities may use one or more physical or economic measures of output (such as quantity of product or total value of shipments) to demonstrate that the affected output has not declined. Tables 2.1 on page 266 and 2.2 on page 268 list some of the possible output measures that might be used to demonstrate that output has not declined. When the output associated with the reported emissions has not declined, the resulting emission reductions would be equal to or less than the amount calculated by an emissions-intensity method, assuming the same measures of output were used. This approach may be used even if it is feasible to use an emissions-intensity method.

Entities that do not intend to register reductions or that wish to supplement their report of registered reductions with a separate subentity report of the reductions in their absolute emissions may use this method even if the output associated with the covered emissions has declined since the identified base period. See subsection 2.4.2 for guidelines on applying this method.

#### 2.2.2.3 Changes in Carbon Storage

This method is to be used whenever the emission reductions (or increases) are associated with changes in the quantity of carbon stocks. Changes in carbon-stock quantities may occur in forests and agricultural soils, wood products, and in geologic carbon sequestration. The year-to-year changes in each distinct type of carbon storage must be estimated independently. Entities may use multiple-year averages for estimating annual carbon fluxes as long as the approaches are consistent with inventory guidance provided in Chapter 1. Because geologic sequestration is associated with the capture of anthropogenic emissions that are the responsibility of the reporting entity, emission reductions associated with changes in geologic sequestration should be assessed as an integral part of an entity's assessment of the affected emissions. See subsection 2.4.3 for guidelines on applying the Changes in Carbon Storage method.

#### 2.2.2.4 Changes in Avoided Emissions

Avoided emissions occur when an energy product (including electricity, hot water, steam, and chilled water) produced by a non- or low-emitting source is distributed to customers that would have otherwise purchased a comparable energy product generated by a higher-emitting source. This method may be used alone or exclusively only if the reporting entity has no emissions associated with such energy exports in their base period; that is, either all of its distributed energy were generated by non-emitting sources or it distributed no energy during its chosen base period. In most cases, reductions associated with distributed energy are calculated using a method that combines changes in emissions intensity and avoided emissions, or by calculating changes in absolute emissions. See subsection 2.4.2 for guidelines on applying this method. In

addition, see subsection 2.4.6 for more specific guidance on the calculation of emission reductions by energy exporters.

#### 2.2.2.5 Action-Specific Emission Reductions

This category encompasses a range of methods designed to assess the emission reductions that result from specific actions not covered by any other methods described. For those entities intending to register reductions based on an entity-wide assessment of their emission changes, action-specific calculation methods should be used only if none of the other methods is feasible. Some of the situations in which action-specific methods might be needed include:

- Entities (or subentities) that cannot use emission-intensity methods and are experiencing declining production.
- Special emission-reduction categories, such as methane recovery from landfills or coal mining.
- Small emitters that are reporting on a specific activity.
- Emission reductions reported, but not registered, by entities.

Regardless of the method chosen, the end result will be an estimate of the emission reductions in the form of tons of carbon dioxide ($CO_2$) equivalent for the year being reported. Technical guidance on how to apply each of these methods is provided in subsection 2.4.5.

### 2.2.3 Identifying Subentities for which Reductions are Calculated

If an entity intends to use more than one method of calculating emission reductions or more than one output measure to calculate changes in emissions intensity, it must identify a distinct subentity for each method or output metric used. Creating a subentity is a way to apportion the entity into discrete sets of emission sources or sinks, each associated with identifiable output. For example, an entity may have two lines of business producing two very different types of products. It might choose to calculate its emission reductions associated with both business lines using the emissions-intensity method, but because it would use two different measures of output, it must define a distinct subentity for each line of business. Another entity may be able to use absolute emissions as its primary method of determining emission reductions, but would still need to create distinct subentities if it chose to register reductions associated with terrestrial carbon storage, such as forestry-related sequestration occurring on its land.

#### 2.2.3.1 Defining Subentities for Large Emitters

To register emission reductions, large emitters must attempt to determine their net entity-wide emission reductions using one or more of the five calculation methods specified in the General Guidelines. To complete an entity-wide assessment of emission reductions, the sum of the emissions of all subentities must equal the sum of the emissions for the entire entity, excluding *de minimis* sources. In the case where the entity has emissions for which no assessment of emission reductions is possible, the entity must report those emissions for one or more distinct subentities and provide an explanation of why no assessment of reductions for those emissions was feasible.

Two or more subentities may share a physical emission source, provided that in preparation of the reporter's emissions inventory, the emissions from the shared source are allocated to each subentity using a method that accurately reflects the subentity's share of the emissions-producing activity or activities associated with that source.

Each subentity for which emission reductions will be calculated using the emissions-intensity method must be associated with a distinct output measure. Two subentities may not use an identical output measure unless the subentities are using different base periods to calculate emission reductions (see Section 2.3, "Base Periods and Base Values").

If a reporter wishes to use the absolute-emissions method to calculate emission reductions for part of its entity, that part of the entity should be reported as a single subentity, unless sources within that part of the entity must use a different base period to calculate emission reductions (see Section 2.3, "Base Periods and Base Values").

If action-specific methods are used, each method used must be applied to emissions and emission reductions that are defined as a distinct subentity.

#### 2.2.3.2 Defining Subentities for Small Emitters

Small emitters that want to register emission reductions must determine the net reductions associated with each activity (e.g., forestry, building operations, tillage, wind power) on which they have decided to report. It is likely that the emission reductions associated with a specific activity will be able to be calculated using a single method. In such cases, the entity would define a single subentity for each activity covered by its report. If more than one method is used, a distinct subentity should be defined for each method. The requirements governing the definition of individual subentities are the same for both large emitters and small emitters.

#### 2.2.3.3 Modifying or Adding Subentities

A reporter may modify an existing subentity included in a previous report or add a new subentity to accommodate a change in the method used to estimate emission reductions. In particular, a subentity may be modified or split into two or more subentities if the reporter determines that changes in the subentity's products or services make it necessary to use one or more new output measure.

A reporter also may add a new subentity if the reporter has established a new, or acquired an existing, business unit that requires a different method or output measure for calculating emission reductions. For further guidance on how to treat new or acquired business units, see the guidance provided for the applicable emission reduction calculation method (see also guidance on establishing a new base period or new base value in subsection 2.3.3).

#### 2.2.3.4 Information on Each Subentity to be Submitted to EIA

The following are the categories of information on each subentity that must be submitted to EIA:

- Name of the subentity (any logical name)
- Location(s)
- Identification of basis for subentity boundaries
- Description of primary activities
- Description of primary emission sources
- Emission-reduction calculation method
- Output measure used (if any)
- Base period
- Base value and data used to derive base value (e.g., emissions, output)
- Reporting-year emissions or carbon sequestration
- Emission reductions in reporting year and data used to calculate emission reductions (e.g., emissions, output, carbon sequestration)
- If the subentity is added after the entity begins to report, indicate whether the subentity was previously covered by any other reports to the 1605(b) Program and whether the subentity's primary activity is new or existed previously

## 2.3 Base Periods and Base Values

### 2.3.1 Choosing a Base Period for Calculating Reductions

When beginning to report, the first year of calculated (registered or reported) reductions must be the year immediately following the Start Year (see § 300.5, "Submission of an entity statement," in the General Guidelines). Consequently, the base period from which those reductions are calculated must be, or must end with, the Start Year.

All emission reductions are calculated relative to an identified base value.[178] In most cases, participants are required to use base values that are derived from the emissions (and related quantities of output or demand) that occurred during the identified base period (the average annual value if the base period is more than one year). For each distinct emission-reduction method used, the entity must determine an appropriate base period. Choosing a one-year base period may simplify the process of starting to report reductions, but choosing the average annual emissions over a base period of 2 to 4 years is more likely to result in a base value that is less affected by annual variations in factors, such as weather, that are not within the control of the entity.

[178] The term "Base Value" has been used for the reference emissions level or emissions intensity against which the current-year emissions level or emissions intensity is compared in order to calculate an emission reduction. The WRI/WBCSD Protocol uses the term "base year emissions" to differentiate entity-level reference emissions from "baseline emissions" as the latter is used in the context of project-based accounting under the Kyoto Protocol. The term "Base Value" is preferred here to the WRI/WBCSD terminology because it can be used generically to refer to an emissions level, an emissions-intensity level, or a benchmark. The term "reference case," which was used in the original 1605(b) program for base-period emissions, has not been used in the revised General Guidelines.

All base periods must end in the Start Year. If a one-year base period is used to derive the base value, that year must be the same as the Start Year. If a multi-year base period is used to derive the base value, the last year of the initial base period must be the Start Year.

In all cases, the first emission-reduction calculation (reported or registered) must occur in the year immediately following the base period (i.e., the First Reduction Year). For those entities intending to register their emission reductions, the last year of the chosen base period must not be earlier than 2002 unless the entity has an existing commitment under the Climate Leaders or Climate VISION programs (see General Guidelines, Section 300.1(c),(1)). For entities that wish to report (but not register) reductions, the last year of the chosen base period must be no earlier than 1990.

The following examples illustrate the determination of base period:

*Example 1.* If a reporter submits a report to register reductions achieved in 2003, the reporter could use one of the following base periods:

- 1 year: 2002
- 2 years: 2001 and 2002
- 3 years: 2000, 2001, and 2002
- 4 years: 1999, 2000, 2001, and 2002

Unless significant changes occurred in the entity or subentity covered by this emission-reduction calculation, the reporter would continue to use the same base period in all future emission-reduction calculations (e.g., 2004, 2005, 2006).

*Example 2.* If a reporter wants to begin reporting emission reductions for 2004, its Start Year (and last year of any base period) would have to be 2003.

*Example 3.* If a reporter wants to begin reporting on reductions that are not to be registered, the Start Year and the last year of the initial base period must still be the year immediately preceding the first year of any reported reductions. In this case, the base period could be as early as 1990 (if the first year of reported reductions was 1991). Alternatively, the reporter would be able to use any 2-, 3-, or 4-year base period, as long as it ended in the chosen Start Year.

### 2.3.2 Establishing Base Values

In order to calculate the emission reductions to be registered or reported under 1605(b), reporters must establish a base value against which to compare reporting-year performance, except in a small subset of action-specific reductions outlined in subsection 2.4.5. The base value may take any one of several different forms, including an historic emissions level, quantity of terrestrial carbon stocks, an historic emissions intensity, or a benchmark emissions intensity against which the reporting-year emissions level or emissions intensity is compared. Benchmarks are either specified by the Department of Energy (DOE) or calculated by the reporter in accordance with DOE guidelines.

Each of the five methods for calculating emission reductions uses a different type of Base Value:

- For changes in emissions intensity, the Base Value will usually be in the form of actual annual emissions in the Base Period per unit of annual output in the base period (or annual averages if the Base Period is more than one year).
- For changes in absolute emissions, the Base Value will usually be the actual amount of annual emissions in the base period (or an average amount if the Base Period is more than one year).
- For changes in terrestrial carbon storage resulting from agricultural or forestry sequestration, the base value is the prior year's carbon stock.[179]
- For those energy exporters using changes in avoided emissions only, the Base Value is the appropriate emissions intensity benchmark specified by DOE. For those energy exporters using changes in avoided emissions combined with intensity, the Base Value is derived from the quantities of electricity or other energy exported in the base period (or the average annual quantity distributed if the base period is more than one year) and any associated emissions, plus the incremental quantity of energy exported in Reporting Year and the emissions for this quantity derived from the appropriate intensity benchmark specified by DOE.
- For action-specific emission reductions, the Base Value can be either the estimated amount of total emissions or emissions intensity of the subject technology or process extant in the base period (whenever these values are estimated based on characteristics of the extant technology or process, a multi-year base period is unnecessary and should not be used).

In all cases, the minimum Base Value must be the value calculated using the entity's (or subentity's) actual emissions, output or other base period performance data. After calculating the minimum Base Value using actual base period emissions and other performance data, entities may choose to establish and use Base Values that are more stringent, i.e., that would result in fewer emission reductions. In such cases, reporters must report the minimum Base Value, as well as identify and describe the basis for the more stringent base value used in its emission reduction calculation.

Over time, Base Values may need to be recalculated or changed to reflect subsequent acquisitions, divestitures, or other significant changes that occur to the entity. The guidelines for such changes are described below. In addition, if an entity improves its emissions-inventory methods and is able to revise its base-period emissions values to reflect the improvements, those changes should also be incorporated in any base values that are affected. Note that if such revisions are made, they will be applied only to current and future reports, not to previously calculated and reported emission reductions.

[179] Reporters may use annual estimates of carbon sequestration, rather than carbon stocks, to estimate reductions. In this case, reductions are the net of all annual fluxes in carbon stocks and are not compared to a base-period carbon sequestration.

## 2.3.3 When to Recalculate or Establish a New Base Value

Once established, a base value should not be changed unless significant changes occur in the make-up of the entity and its production processes, or in the characteristics of its product or output. If warranted, however, there are two types of changes that can, and sometimes must, be made to a base value:

1) *Recalculating Base Values:* Base-period emissions, carbon stocks, and/or output quantities should be recalculated to reflect certain significant changes in the entity or significant improvements in emission or sequestration estimation methods that occurred since the base value was established; or

2) *Establishing a New Base Period:* A new (more recent) base period must be established if recalculation of the base value is not possible and significant changes have occurred in the make-up of the entity and its production processes, or in the characteristics of its product or output. When a new base period has been established, a new base value must then be calculated.

Entity changes occurring on or before May 31 of a given calendar year that require changes to base values or base periods must be reflected in the report submitted covering emissions and reductions for the following calendar year. Reporters may choose to postpone incorporating changes to base values or base periods if the forcing entity changes occurred after May 31 until submitting the report covering emissions and reductions for the year after the following calendar year. This grace period of at least 12 months is provided to allow reporters sufficient time to integrate data management systems to enable recalculation of base values to reflect the reconfigured entity and new base period. The recalculation of new base values or establishment of a new base period should not result in a gap in the entity's annual reporting. Such revisions may not be used as the basis for revised prior year reports of emission reductions.

### 2.3.3.1 Recalculating Base Values

Over time, an entity or subentity may undergo a variety of changes that result in the transfer of emission sources and/or sinks, making it difficult to determine actual changes in emissions intensity (or absolute emissions). Those changes could include mergers, acquisitions, divestitures, and the outsourcing or insourcing of significant elements of the production process. An entity might also change the methods used to measure its greenhouse gas emissions, especially if the entity has developed more accurate methods since the emissions were initially estimated. If such changes are likely to distort the calculation of emission reductions, the entity should first attempt to eliminate or minimize such distortions by recalculating the base values from which emission reductions are calculated.

#### 2.3.3.1.1 Acquisitions and Divestitures

An entity or subentity that gains or loses significant sources of emissions through a merger, acquisition, or divestiture must adjust its base value of emissions to reflect this transfer, if the historical records of the affected units are available and such an adjustment is feasible. A

significant source is defined as one representing 3 percent or more of emissions measured in units of carbon dioxide equivalent ($CO_2e$) in the base period. Acquired entities should only be incorporated into a previously established Base Value if they existed in the relevant Base Period of the acquiring entity and the required emissions and output data is available and is reported to EIA. In general, such adjustments should be made only on the basis of a full year of performance data, although base-period emissions may need to be adjusted on a pro rata basis if the merger, acquisition, or divestiture occurs in the middle of the year.

An entity or subentity using an intensity Base Value may choose not to adjust Base-Period emissions if the emissions gained or lost in the transfer of the source(s) also resulted in a corresponding and commensurate gain or loss of output. For purposes of this guidance, a commensurate gain or loss of output shall be determined as an increase or decrease that is within 3 percent of the percentage increase or decrease in the entity's or subentity's emissions.

#### 2.3.3.1.2 Outsourcing/Insourcing

An entity or subentity that gains or loses significant sources of emissions through insourcing or outsourcing of particular elements of its production process must adjust its Base Value of emissions to reflect this transfer, if adequate records of the affected emissions exist. Significant sources are defined as those representing 3 percent or more of emissions measured in units of carbon dioxide equivalence in the base period. In general, such adjustments should be made only on the basis of a full year of performance data, although base-period emissions may need to be adjusted on a pro rata basis if the insourcing or outsourcing occurs in the middle of the year.

### 2.3.3.2 Establishing a New Base Period or New Base Value

To the extent possible, an entity should continue to use the same Base Period and Base Value established in the initial report. However, if there has been a fundamental change in the entity or subentity, then a reporter may change the Base Period and Base Value, provided that a justification is provided and the entity has submitted complete reports for each year since its original Start Year. DOE anticipates that resetting the Base Period will be limited to circumstances in which there has been a fundamental change in the output of an entity or subentity between the original base period and the reporting year. Those circumstances include the following:

- *Creation of a New Business Unit.* The reporting entity creates a new business unit composed of one or more new facilities, reports emissions for this new business unit as a separate subentity, and uses a method and/or output measure to calculate emission reductions that is clearly distinct from any other method/output measure used by that entity.
- *Redefining Entities/Subentities.* A reporting entity decides that the lines of business of its entire entity or a specific subentity have diverged sufficiently that it should be reported as two or more subentities. The reporting entity would be permitted to use a different Base Period for a subentity that was not included in the original base period and for which a new output measure is used to measure intensity.

*Example.* A plastic container manufacturer converts a plant making 20-ounce soda bottles to the production of liquid detergent containers. The manufacturer decides that the output measure of emissions per container used in the original Base Period is no longer a comparable output measure with emissions per container after conversion to production of liquid detergent containers. The manufacturer may reset the Base Period to the first full calendar year of producing liquid detergent containers.

- *Merger of Entities.* A new entity resulting from the merger of two or more firms or other entities, at least one of which reported previously under the revised 1605(b) guidelines, would be able to reset the base period if the merger partners used different base periods in reporting previously under 1605(b) and/or one of the partners does not have data available for the earlier base period originally established by the other merger partner.

  *Example.* A tire manufacturer's plant in the initial base period produced only passenger-car tires. The manufacturer expands this plant to produce truck tires as well and decides that the number of tires produced is no longer an appropriate output measure. For reporting purposes, the reporter segments the plant into two subentities. One subentity covers the manufacturing of passenger-car tires, retains the original base period, and uses the number of passenger-car tires produced as the output measure. The second subentity covers the manufacturing of truck tires, for which the first full calendar year of production becomes the base period and the number of truck tires produced is the output measure.

- *Acquisition of a New Business Line or Subentity Not in Existence in the Base Period.* The reporting entity acquires a unit of another company that either was not in existence in the reporting entity's original base period or for which data are not available for that base period.

  *Example.* If a divestiture, acquisition, product change, or other development makes the original base value a poor indicator of the entity's efforts to reduce emissions and recalculation of the base value is not feasible, an entity must choose a new, more current base period, and establish a new base value.

When changing the base period used by an entity or subentity to determine the base value of emissions, the new base period should be the earliest period after the original base period established in the reporter's first report for which emissions and output data are available. The reporter may change the number of years in the base period.

#### 2.3.3.3 Documentation of Changes in Base Periods or Base Values

Whenever a Base Period or Base Value is modified or replaced, the entity must report to EIA the reasons why a change was necessary, and provide a rationale for the specific changes made.

# 2.4 Technical Guidelines for the Application of Specific Calculation Methods

The following sections provide guidance on each of the five basic calculation methods for calculating emission reductions identified in the General Guidelines: (1) changes in emissions intensity; (2) changes in absolute emissions; (3) changes in carbon storage; (4) changes in avoided emissions; and (5) action-specific. Calculating emission reductions associated with the generation and distribution of electricity, steam, and hot or chilled water (exported energy) often requires combining methods for calculating reductions from changes in intensity with methods for calculating changes in avoided emissions. Such combined methods are described as part of a special section (2.4.6).

## 2.4.1 Changes in Emissions Intensity

Calculating emission reductions based on changes in emissions intensity is an important objective of the enhanced system for Voluntary Reporting of Greenhouse Gases. Emissions-intensity methods described in this section can be used to calculate reductions for a broad range of entities or subentities.

Depending on the type of output measure(s) chosen, emissions-intensity methods can be used to calculate changes broadly across a large entity or, more narrowly, those changes associated with a specific process or facility. Ideally, the output measure used in developing an emissions-intensity factor should be a good indicator of year-to-year changes in the physical and economic output associated with the covered emissions over a period of many years.

The most important first step should be a review of the potential measures of output most relevant to an entity's operations and to the scope of emissions covered by the entity's activities. This section provides guidance on the types of output measures that should be considered and the selection criteria to be used, although the guidelines also allow most entities to choose the output measure that seems best-fitted to their particular circumstances. Specific guidance on output measures and calculation methods for generators of electricity and other forms of distributed energy is provided in subsection 2.4.4.

### 2.4.1.1 Output Measures and Intensity Metrics

Many reporters already have experience reporting energy-intensity and/or greenhouse gas-intensity data for their operations. Companies receiving Federal and/or State funds to deploy energy-efficiency equipment or processes likely have had to report their energy-intensity improvements over time. Many entities participating in the Climate VISION and Climate Leaders programs have established greenhouse gas-intensity targets.

Greenhouse gas intensity metrics, which are designed to indicate changes in emissions that are independent of economic growth or increases in production, use either a physical or an economic value for the denominator (see Table 2.1). For example, the greenhouse gas emissions intensity

of steel production can be measured as emissions per ton of steel product (physical metric), or emissions per dollar of value added by the steelmaker (economic metric). The denominator can be an input into the manufacturing facility when the output slate is complicated—for example, a refiner could report emissions per barrel of crude oil processed.

Physical measures of output are typically used for commodity industries with homogeneous production outputs (e.g., tons of steel, aluminum, or paper). Physical measures also include floor area (square feet or square meters), number of employees, and units of product manufactured or assembled.

Economic measures (e.g., "value of shipments" and "value added") are typically used when aggregating across heterogeneous entities that do not produce comparable products, such as in fabrication industries, manufacturers of machinery and textiles, and food processing. These measures may be more practical for more complex industries or firms that produce a variety of disparate products. "Value of shipments" from the surveyed firms is reported by the U.S. Department of Commerce's Bureau of Economic Analysis, and "value added" is reported in the Census Bureau's *Annual Survey of Manufacturers.*

Typically, there is greater variability in economic measures relative to physical measures and physical measures values more accurately trace actual trends in emissions intensity. However, heterogeneity of the products manufactured by most industrial plants can make development of such physical metrics challenging. There have been increasing efforts to develop suitable physical metrics in the United States, Netherlands, and Canada

### Table 2.1. Greenhouse Gas Intensity Denominators for Industry and Service Companies

| Physical Measures | Economic Measures[180] |
|---|---|
| Weight of product or output (lb, ton, metric ton) | $ Gross output |
| Number of units of product | $ Value of shipments |
| Quantitative description of function or service provided | $ Value added |
| Units of energy sold (kWh, Btu, bbl) | $ Revenue |
| Units of input processed (bbl crude) | |
| Number of employees or students | |
| Floor area ($ft^2$, $m^2$, etc.) | |

Mergers and acquisitions, plant closings, varying product lines (crossing industrial categories), and other structural changes can obscure output trends based on both physical and economic metrics. Specific adjustments to base values may be needed to add or subtract business units that have been acquired or divested, or to include or exclude stages of the production process that have been insourced or outsourced. Those adjustments would be made if the emissions associated with the applicable elements of the production process have been measured separately or can be estimated.

[180] Economic metrics must be adjusted for inflation.

### 2.4.1.2 Output Measure Selection Criteria

Each reporter can select the output measure(s) most relevant for its entity and/or subentities. DOE has already reviewed the measures used successfully by others in the United States and abroad to track both energy intensity and greenhouse gas intensity. Since its first request for comments from interested parties in the summer of 2002, DOE has received some very specific recommendations and interviewed representatives of trade associations and manufacturing entities to obtain a better understanding of what is practical. Based on this input, DOE offers the following criteria to assist reporters in selecting appropriate output measures:

- ***Select an output measure that can work over time***. Reporters should revise their base period(s) only when necessary. Consistency in the output measure will enable the reporters and DOE to track the trends toward the goal of an 18-percent reduction in greenhouse gas emissions intensity.

- ***Choose physical measures over economic measures as the preferred measure of output***. Physical measures of output or input (see Table 2.1) work well for most commodity industries (e.g., steel, cement, paper) and select service establishments (e.g., office building, schools). Manufacturing establishments with heterogeneous products (e.g., fabrication, food, textiles) may not lend themselves to a single physical measure even if reporting is performed for subentities. DOE recognizes that in such circumstances an economic measure may be preferred. Economic measures should be denominated in current dollars: EIA will convert to constant dollars using the Gross Domestic Product (GDP) price deflator. The GDP deflator is a measure of the cost of goods and services purchased by U.S. household, government, and industry. EIA will provide a worksheet for reporters to gauge the effect of such a calculation on the computation of reductions. Please refer to Table 2.2 for examples of possible output measures categorized by industrial codes of the North American Industry Classification System (NAICS).

- ***Select the broadest possible physical output measure***. The simplest way to report is at the entity level, with a single measure of output that is sufficiently robust to cover all manufacturing and supporting operations. If that is not possible, consider reporting greenhouse gas emissions from subentities with appropriate physical metrics for the various products and other measures of performance. If establishing intensity metrics based on physical measures of the output of subentities is not feasible, consider reporting greenhouse gas emissions from subentities with appropriate economic metrics for different products. Aim for the broadest coverage feasible.

- ***Apply the one output measure: one subentity rule***. In those cases where subentities are necessary, each subentity should have a unique measure of physical output. Subentities with identical outputs should be grouped together as a single subentity, unless they have different Base Periods.

- ***Use output measures that have a track record***. For example, use metrics that have already been reported to a trade group or other data-gathering organizations, such as the Census

Bureau. Explaining and justifying the selection of an output measure is easier if the measure has been used previously by the reporter or other entities with the same types of output.

- ***Set limits on changing the metric***. Changes in major manufacturing processes or product slate, mergers, acquisitions, and divestitures, may necessitate the use of an alternative metric. In select cases, changing the base periods may be sufficient and the instructions in subsection 2.3.3.2 can be followed. In other situations the metric used historically may no longer be relevant.

- ***Document all output measures.*** All entities must (a) provide a rationale for the selection of each output measure, (b) define and describe each output metric, including calculations and factors used, (c) provide a few years of trend data for any new intensity metric developed, and (d) describe the scope of activities covered by the chosen output measure.

### 2.4.1.3 Calculation Approach

For changes in intensity, the calculation is straightforward for an entity or subentity: calculate the change in greenhouse gas (GHG) emissions (in tons) by subtracting the base period greenhouse gas intensity from the reporting year greenhouse gas intensity and multiply the change by output in the reporting year. This approach is represented by the following equation.

$$\text{GHG Emission Reduction} = [(E_B/O_B) - (E_R/O_R)] * O_R$$

**Where:**

| | | |
|---|---|---|
| **E** | **=** | **greenhouse gas emissions (in tons)** |
| **O** | **=** | **output measure (in selected measure)** |
| **(E/O)** | **=** | **GHG intensity** |
| **R** | **=** | **Reporting Year** |
| **B** | **=** | **Base Period(s)** |

It is important to note when using this formula, a positive change (Base Period is higher than Reporting Year) is an emission reduction in greenhouse gas intensity; a negative change (Base Period in lower than Reporting Year) is an increase in greenhouse gas emissions. If applicable, the reporter sums the changes in greenhouse gas emissions for each of the subentities to calculate total net reductions. The total net change in greenhouse gas emissions will be the final number reported to EIA.

### 2.4.1.4 Partial List of Physical Output Measures Currently in Use

Table 2.2 provides a list of suggested measures of physical output currently in use by NAICS codes.

**Table 2.2. Partial List of Physical Output Measures Currently in Use by NAICS Codes**

| NAICS | NAICS Description | Physical Units |
|---|---|---|
| 111 | Crop Production | metric tons |
| 113 | Forestry and Logging | acres |
| 212 | Mining (except Oil and Gas) | metric tons |
| 221 | Utilities | kilowatt-hours, revenues ($) |
| 311 | Food Manufacturing | short tons, metric tons, lbs, kg, sacks (flour), bushels (wheat), kilolitres |
| 313 | Textile Mills | 1,000 lbs, million hours (spindle), bales (cotton), square yards (fabrics), lbs (tie cord) |
| 314 | Textile Product Mills | square yards, dozens |
| 321 | Wood Product Manufacturing | billion board feet, cubic meters |
| 322 | Paper Manufacturing | short tons, metric tons |
| 323 | Printing and Related Support Activities | square meter |
| 324 | Petroleum and Coal Products Manufacturing | million barrels per day (crude throughput) |
| 325 | Chemical Manufacturing | short tons, metric ton, gallons, cu ft |
| 326 | Plastics and Rubber Products Manufacturing | metric tons |
| 327 | Nonmetallic Mineral Product Manufacturing | billion square feet, short tons, metric tons, tones (clinker), kilograms, million dozen (tumblers, cookware, stemware), million pieces (tableware), 1,000 bricks, square meters (wall tile) |
| 331 | Primary Metal Manufacturing | million tons by metal smelted, 1,000 short tons (steel in process, finished steel), 1,000 metric tons by grade (carbon, alloy, stainless) & furnace type |
| 332 | Fabricated Metal Product Manufacturing | million tons by metal, 1,000 units by type |
| 333 | Machinery Manufacturing | units by type ,units by fuel (gas, diesel, NG, LPG) |
| 334 | Computer and Electronic Product Manufacturing | units by type, square meters of silicon |
| 335 | Electrical Equipment, Appliance, and Component Manufacturing | units by type, 1,000 lbs gross (by type of material), 1,000 units (if product type does not change substantially over time) |
| 336 | Transportation Equipment Manufacturing | units by type (cars, trucks), vehicle |
| 337 | Furniture and Related Product Manufacturing | units by type |
| 339 | Miscellaneous Manufacturing | units by type |
| 442 | Furniture and Home Furnishings Stores | units by type |
| 486 | Pipeline Transportation | barrels of throughput |
| 51 | Information | employees, square feet of building space |
| 523 | Securities, Commodity Contracts, and Other Financial Investments and Related Activities | square feet of building space |

| NAICS | NAICS Description | Physical Units |
|---|---|---|
| 531 | Real Estate | square feet of building space, by category of commercial building; number of apartments or residential units |
| 541 | Professional, Scientific, and Technical Services | square feet of building space, employees |
| 562 | Waste Management and Remediation Services | tons waste processed |
| 611 | Educational Services | student enrollment, faculty employment |
| 62 | Health Care and Social Assistance | beds, square feet |
| 812 | Personal and Laundry Services | lb laundry cleaned, employees |
| 813 | Religious, Civic, Professional, and Similar Organizations | square feet of building space, by category of commercial building |
| 814 | Private Households | household, person |
| 921 | Executive, Legislative, and Other General Government Support | employees, square feet of building space, by category of commercial building. |
| 928 | National Security and International Affairs | sq. ft., employees |

## 2.4.2. Changes in Absolute Emissions

In general, the formula for determining emission reductions for the entire entity or for each sub-entity using the absolute-emissions method is:

$$\textbf{Change in GHG Emissions} = AE_B - AE_R$$

**Where:**

**AE = absolute greenhouse gas emissions (in metric tons)**

**R = Reporting Year**

**B = Base Period**

The reporter then sums the changes in greenhouse gas emissions for each of the subentities. The total net change in greenhouse gas emissions will be the final number reported to DOE. It is important to note when using the formula above, positive changes are reductions in GHG intensity; negative changes are increases in greenhouse gas intensity.

This calculation method may be used by any entity to calculate and report emission reductions. However, entities that intend to register emission reductions may use this method only if the entity can demonstrate that the output associated with the absolute emissions has not declined. To do this, reporters must identify a physical or economic measure that can serve as a sufficiently credible proxy for output and changes in output. Some acceptable output measures are described above in subsection 2.4.1.2.

Entities or sub-entities that experience year-to-year declines in output and intend to register reductions may continue to use this method as long as their current output is at least equal to

their Base Period. An entity may not use this method to qualify for registered reductions for any year that its overall output is lower than it was in its Base Period. However, an entity that experiences one or more years of lower output may continue to report, and may use this method of calculating emission reductions to qualify for registered reductions in the future, if its output again equals or surpasses its Base-Period output.

Another option for an entity that begins to experience sustained periods of declining output relative to its Base Period is to calculate its emission reductions using one or more subentities. Changes in the emissions of those subentities with declining output might be assessed using emissions-intensity methods, while subentities with stable or increasing output could continue to be assessed using absolute-emissions methods.

The value of the Base-Period emissions used to calculate changes in absolute emissions must be adjusted to reflect boundary changes, including the acquisition and divestiture of significant emission sources and the outsourcing or insourcing of significant emission-producing activities. Base-Period emissions must represent all sources of emissions included in the entity's emissions inventory for the reporting year, and exclude sources or activities that have been divested or outsourced (i.e., sources or activities that have been transferred to another entity and are still producing emissions).

Base-Period emissions may include emissions from sources that are no longer emitting in the Reporting Year. No adjustment may be made, however, to Base-Period emissions resulting from the addition of new emission sources, unless the reporter can demonstrate that the addition of this source represents the insourcing or acquisition of an activity previously conducted by another entity in the Base Period (rather than establishment of a new activity or expansion of an existing activity some time after the chosen Base Period—also referred to as organic growth).

## 2.4.3. Changes in Carbon Storage

Entities reporting under 1605(b) are eligible to register reductions associated with increases in carbon stocks. The next subsection describes the procedures that should be followed to calculate annual volumes of reductions associated with increases in carbon stocks. Entities can calculate reductions from:

- Increases in terrestrial carbon stocks (forest, agriculture, rangelands).
- Increases in carbon storage in wood products.
- Preservation of existing terrestrial carbon stocks.

Geologic carbon sequestration requires an action-specific method and is discussed in subsection 2.4.5.6.5.

### 2.4.3.1 Calculating Reductions from Increases in Terrestrial Carbon Stocks

Entities with carbon emissions from terrestrial carbon stocks that exceed *de minimis* criteria of the 1605(b) Program must report estimates of annual carbon fluxes consistent with the General Guidelines. Absolute increases in terrestrial carbon stocks can contribute to an entity's registered

greenhouse gas reductions within the 1605(b) Program. Terrestrial carbon pools that can be enhanced include: forest trees, forest understory, forest dead and downed wood (onsite), forest floor, forest soils, agricultural soils, range and grazing land soils, and wood products. Under this provision, entities are required to use inventory methodologies described in Chapter 1, Parts H and I to estimate total carbon stocks and/or fluxes from carbon pools on lands being reported, and methods found in this section for calculating reductions.

Changes in terrestrial carbon stocks can either be positive (carbon sequestration) or negative (carbon emissions). Chapter 1, Parts H and I provide two options for calculating the changes in carbon stocks. Entities can calculate annual carbon fluxes directly as the quantity of carbon sequestered or emitted. Otherwise, entities can calculate annual carbon fluxes by assessing the total carbon stocks at the beginning and end of a period.

In cases where carbon-stock estimates are used to generate the carbon-flux estimates, entities should report both the carbon stock and flux values to enhance transparency. In many cases, entities will develop estimates of carbon stocks and fluxes for base and reporting years from periodic inventories or estimates, made at 5-year increments. While this is acceptable, entities are required to report this information annually and use the inventory guidelines described in Chapter 1 to generate an annual estimate. In no case should an entity use a projection to estimate carbon-stock values for the base period.

#### 2.4.3.1.1 Purchase or Sale of Land

Entities' landholdings may change over time. If lands being reported under 1605(b) are sold or divested, the entity selling the land must reduce its carbon-stock estimates for the reporting year and the base period to reflect that the land is no longer under the entity's control. Entities purchasing lands that are already being reported under 1605(b) may continue to report on those lands, and can estimate reductions based on the fluxes that occur in the first year of ownership or on the change of carbon stocks from the year prior to purchase, based on the value reported by the entity that sold the land.

Entities choosing to use a base period that ends after 2002 that owned the affected land during 2002 must provide an estimate of the change in carbon stocks that occurred from the end of 2002 to the end of the chosen Base Period. Entities that purchased land after 2002 that has not been reported previously under 1605(b) should provide an estimate of the change in carbon stocks from the year of purchase to the end of the chosen Base Period.

#### 2.4.3.1.2 Carbon Emissions from Land Use in the Base Period

In some cases, an entity's base-period inventory will indicate a decline of carbon stocks (net carbon dioxide emissions). Emissions of carbon dioxide from land use can result from the cultivation of organic soils, cultivation of mineral soils, forest management practices, and land conversion.

Cultivated organic soils include histosols, mucks, and peats that have been drained and converted to crop or pastureland. Because carbon dioxide emissions from organic soil cultivation can continue essentially indefinitely (for periods of more than 100 years), entities that report

emissions of carbon dioxide from organic soil cultivation should use the guidance for calculating changes in emissions intensity (see subsection 2.4.1) or changes in absolute emissions (see subsection 2.4.2) for estimating registered reductions associated with carbon emissions from this land use.

Because carbon dioxide emissions associated with most other land uses occur for a finite period (from 1 to 20 years) and cease once the land reaches a new equilibrium condition, entities reporting carbon dioxide emissions from all land uses except organic soil cultivation should use the methodologies for calculating increases in terrestrial carbon stocks. Entities should use the carbon stocks at the end of the base period as the basis for the reductions calculation.

#### 2.4.3.1.3 Natural Disturbances

Entities that experience a natural disturbance such as natural fire, pests, or extreme weather, can choose to account separately for the emissions associated with these natural phenomena. Entities reporting emissions from natural disturbances separately should identify the emissions and the cause so that they can be tracked separately and noted in summary information made available by EIA. Entities cannot report additional reductions associated with increases in carbon storage on lands that have undergone natural disturbances until the carbon stocks return to pre-disturbance levels.

### 2.4.3.2 Reductions from Increases in Carbon Stored in Wood Products

The Guidelines specify that the entity reporting changes in forest carbon stocks also report the changes in carbon stocks that are expected in the wood-products pool. Because harvested wood is typically transferred between owners as the wood is harvested, processed, and used, several entities could potentially affect the quantity and timing of the carbon emitted from wood products. The decision to allow the forest-carbon reporter to also report expected changes in wood-products carbon simplifies overall reporting burdens and allows the increases in wood-products carbon storage to be captured in the 1605(b) reporting systems.

Carbon harvested and removed from forests will not generally flow to the atmosphere immediately. Significant quantities of carbon harvested from forest systems is likely to be stored for long periods in the form of wood products or in materials deposited in landfills, and some of this carbon is likely to permanently sequestered. Since most declines in carbon stocks would be treated as an emission increase under the revised guidelines, entities that are reporting changes in terrestrial carbon stocks should also include in their reports estimates of the expected storage of carbon in wood products. The guidelines allow two approaches to estimate the amount of carbon stored in wood products.

The first approach is to estimate the decay of materials stored in wood products over time so that the resulting emissions are accounted for in the year in which they occur. This would require entities to report each year an estimate of the decline in the carbon stored in the wood products that were derived from the materials harvested by the entity since the base period. The following formula would be used to estimate the carbon stored in the wood products in a given year.

$$\text{Carbon Stored in Wood Products} = \Sigma_{\text{(for base to reporting year)}} \text{Volume of Carbon Harvested}_{\text{(year)}} * \%\ \text{Stored in Products}_{\text{(year)}}$$

Because this first approach would require entities to report on all materials harvested since the base period in each reporting year, many entities may find it overly burdensome. Such entities could choose a much simpler approach. This second approach would allow an entity to register the amount of carbon expected to remain in products and landfills after a 100-year period and to report this value in the year that the material is harvested. This approach would mean that the emissions likely to be produced by wood products over a 100-year period would be accounted for in the year of harvest. The following formula would be used to estimate the carbon stored in the wood products 100 years after harvest.

$$\text{Carbon Stored in Wood Products} = \text{Volume of Carbon Harvested} * (\text{100 Year Residue})$$

Reporting entities must identify which of these two approaches they used and provide to EIA the data and spreadsheets or worksheets used to calculate these values. See the Appendix to Chapter 1, Part I, sections 1.C and 1.D.

### 2.4.3.3 Reductions from Carbon Stock Changes on Incidental Lands

Incidental lands are entity landholdings that are a minor component of an entity's operations and are not actively managed for production of goods and services, including: transmission, pipeline, or transportation right of ways that are not managed for timber production; land surrounding commercial enterprises or facilities; and land where carbon stock changes are determined by natural factors. If the incidental lands are not developed during the reporting period, entities have the option to use the guidelines in Chapter 1, Parts I to estimate changes in above- and below-ground carbon stocks on incidental lands or to assume that carbon stocks on incidental lands are not changing. Regardless of which option is chosen, entities must report on the area and type of incidental lands owned. If incidental lands are converted to developed uses, the impact of development on carbon stocks must be accounted for in the entity inventory according to the guidance in Chapter 1, Part I, "Forestry Emissions."

### 2.4.3.4 Reductions from Land Restoration and Preservation

The revised 1605(b) General Guidelines allow entities to accelerate the registration of reductions associated with land restoration and preservation activities. To be eligible for this provision, an entity must restore native habitat on land and place administrative restrictions on the land to ensure that human-caused releases of carbon from the lands do not occur in the future. Administrative restrictions can either be permanent conservation easements that are registered with the County, State, or other Government entity, or deed restrictions. The entity can register 50 percent of the carbon stock increases that are expected over the 50 years following the activity's inception and the establishment of permanent easement or deed restriction. These carbon-stock increases should be calculated using the guidelines for calculating increases in terrestrial carbon stocks outlined in Chapter 1, Part I.4. No additional reductions (or changes in carbon stock) attributable to these lands may be reported or registered. However, all inventory

reporting provisions contained in Chapter 1 of these Technical Guidelines continue to apply to these lands.

## 2.4.4. Avoided Emissions

As used in these Technical Guidelines, avoided emissions occur when an energy product (including electricity, hot water, steam, and chilled water) produced by a non- or low-emitting source is distributed to customers that would have otherwise purchased a comparable energy product generated by a higher-emitting source. This subsection provides technical guidance on applying this method, which in some cases may be used alone, as described below, but in most cases should be used in combination with the Changes in Intensity method, as explained in section 2.4.1.

### 2.4.4.1 Calculating Reductions Associated with Avoided Emissions

Producers of electricity, steam, and hot or chilled water must use this method combined with the Changes in Intensity method to calculate the emission reductions associated with any increases in the quantity of energy they have generated for distribution (to other entities or users) as described below.

If the entity or subentity generating the energy had no emissions in its chosen Base Period, emission reductions associated with the generation and distribution of electricity, steam, heat or cooling must be calculated using only the changes in avoided emissions method. This is likely to be true for only those entities that distribute energy that is generated, exclusively, by nuclear power or renewable energy (e.g., wind farms), and those entities or sub entities that did not distribute energy during their chosen Base Period (e.g. a new, independent gas-fired combined cycle power plant that wasn't operational during the Base Period). These reductions are calculated by multiplying the quantity of incremental generation (the difference between the Reporting Year Generation and the Base Period generation) by the difference between an entity's Reporting Year emissions intensity (or zero, if there are no emissions) and the appropriate Benchmark emissions value:

$$\textit{Reductions}_{\textit{Incremental}} = (\textit{Benchmark Intensity} - \textit{Emissions Intensity}_{\textit{Reporting Year}}) * \textit{Incremental Generation (MWh or MMBtu)}$$

### 2.4.4.2. Avoided Emissions Benchmark(s) and Indirect Emissions Conversion Factors

From time to time, EIA will calculate and publish avoided emissions benchmarks and indirect emissions conversion factors for use in calculating emission reductions. The benchmarks will differ from the emissions coefficients used in the development of emission inventories, but must be used in all calculations of emission reductions involving either avoided emissions or indirect emission reductions. EIA may coordinate the timing of any changes in such benchmark or emission conversion factors with the periodic review and updating of the guidelines by DOE pursuant to Section 300.1 (f) of the General Guidelines.

#### 2.4.4.2.1. Avoided Emissions Benchmarks

The avoided emission benchmark for electricity generation will be an approximation of the average emissions intensity of fossil-fired electric power generation for state-based regions in a recent year, except that no benchmark will be higher than 0.9 metric tons of carbon dioxide equivalent per megawatt hour of generation. The regional benchmarks for avoided emissions will be based on the same regions as those specified by EIA for indirect emissions for purchased electricity. The average intensity of the fossil-fired electricity generation in the 2002 was approximately 0.9 metric tons of carbon dioxide equivalent per megawatt hour generated (at the point of generation). National and regional values fluctuate annually as a result of a wide range of different factors, including the relative prices of different fuels used in power generation and weather. Therefore, EIA may choose to calculate an average value for two or more years. These factors are also expected to change over time as new power plants are built and existing plants are retired. The values will be recalculated by EIA whenever the electric sector has undergone permanent changes that are clearly more significant than the changes likely attributable to non-permanent annual variations.[181] EIA will also specify and periodically update avoided emission benchmark values for distributed heating and cooling energy, based on these guidelines and the best data available.

#### 2.4.4.2.2. Indirect Emissions Factors for Calculating Reductions

Indirect emissions factors must be used by reporters seeking to quantify emission reductions associated with reduced purchases of electricity, heat, or cooling. For purchases of electricity, indirect emissions factor(s) specified by EIA will reflect the emissions from fossil-fired plants in the region in which the electricity demand occurred that are necessary to deliver one megawatt hour of electricity to the point of use. For example, in 2002, on the basis of national data, a megawatt hour of electricity at the point of use required emissions of 0.64[182] metric tons of carbon dioxide equivalent emissions, on average, to generate. Such factors will vary annually as result of a number of different factors, such as weather. For this reason, EIA may specify factors that reflect a single year or a multi-year average. These factors are also expected to change over time as new power plants are built and existing plants are retired. The values will be recalculated by EIA whenever the electric sector has undergone permanent changes that are clearly more significant than the changes likely attributable to non-permanent annual variations.

#### 2.4.4.2.3. Avoided Emissions Benchmarks and Indirect Emissions Factors for Activities Outside of the United States

To establish an avoided emissions factor, entities reporting emission reductions achieved outside the United States should use the average greenhouse gas emissions intensity of fossil-fired electricity generation for the country in which the electricity was generated or used, as published

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[181] Based on values recently adopted by the California Climate Action Plan's General Reporting Protocol (0.8 for natural gas-fueled absorption chillers and 1.2 for natural gas-fueled engine driven compressors), this value is 0.63 kg $CO_2$/ton hour of cooling.

[182] U.S. Energy Information Administration. *Annual Energy Outlook 2004*. Table 73-Electric Power Projections for EMM Region/United States (January 2004), with an 8 percent loss attributable to transmission and distribution.

in the most recent report of such statistics issued by the International Energy Agency (IEA).[183] If such statistics are not available from the IEA, they should be obtained by the official government statistics for that country. If no official government statistics exist, the U.S. benchmark value should be used. For thermal energy, entities should use the values specified for the United States, unless the reporter can determine the appropriate values for each country for which such values are required, using the same basic assumptions specified above. Indirect emissions factors should be derived using the same methodology, but should also include an adjustment for the typical losses incurred in the transmission and distribution of energy within the borders of the country for which activities are being reported.

### 2.4.5. Action-Specific Calculation Methods

There are certain circumstances, defined by DOE, in which action-specific calculation methods presented in this subsection may be used to estimate emission reductions. There are a number of special circumstances or actions that result in emission reductions that cannot or should not be quantified using any of the measurement or other estimation methods provided for in these guidelines. For example, there may not be historic data readily available on a relevant output metric that allows the reporter to capture the effect of a specific action on emissions intensity. At the same time, overall output associated with the specific action may be declining, precluding the calculation of emission reductions based on changes in absolute-emissions levels. The specific action also may not result in an avoided emission from electricity, steam, heat, or cooling generation, and may not yield a change in carbon-storage levels. In addition, there are many situations for which the special methods defined in this section were specifically designed.

It is likely that most specific actions can be defined as distinct subentities and associated emission reductions can be calculated using methods described in subsections 2.4.1 through 2.4.4. If an entity is intent on registering emission reductions, it must, wherever feasible, use one of these methods to calculate its emission reductions. However, for the small set of specific actions in which emission reductions cannot be quantified using any of the other methods identified, entities intending to register emission reductions should use the action-specific calculation methods identified in this section. Entities not intending to register reductions may use action-specific calculation methods whenever they are applicable.

Reductions calculated using action-specific methods should be consistent with all principles applicable to the other four calculation methods identified under these Technical Guidelines. Those principles include:

- The reporter should clearly identify the name and nature of the action undertaken to reduce emissions.
- The reporter must clearly describe the activities and emission sources affected by the action.
- Emissions and emission reductions affected by this action should not appear in any other subentity or entity-wide emission-reduction calculation submitted by the reporter.

[183] International Energy Agency. *World Energy Outlook*, web site: www.worldenergyoutlook.org.

- Emission reductions reported using this calculation method may not be reported by any other entity on an entity-wide or subentity basis.
- Base-year or base-period emission levels should be calculated for the year(s) prior to the entity's first reporting year.
- Base-year or base-period emissions must be derived from actual or estimated emissions for the extant process or technology in the entity's base period.
- Reporters should submit emissions and emission-reduction data on an annual basis subsequent to the first reporting year. If a reporter fails to report on a specific action in a subsequent year, future submissions must include data for all intervening years.

#### 2.4.5.1 Documenting Specific Actions

In addition to the information required for any subentity, the following general information should be reported:

- Action-specific name – Ensure that the name of each action-specific subentity clearly identifies the specific action being reported. It should be distinct from the entity name or the name of any other subentity. If the action is repeated at several facilities with differing base-year technologies or processes, each distinct action must be reported as a separate subentity and the name should indicate both the specific action and the facility covered.

- Date action was initiated – Provide the month and year that the specific action was initiated.

- Reason(s) for specific action – Indicate whether the specific action was undertaken voluntarily, or as part of a Federal, State, or local requirement.

- Description of specific action – Provide a detailed description of the specific action taken. For example, if an entity has installed more efficient motors in a manufacturing plant, the report should indicate the efficiency of the motors displaced and the efficiency of the replacement motors.

- Activities affected – Reporters should indicate the activities affected by the specific action used to reduce emissions. To the extent possible, those activities should be discrete and definable by technology, equipment, process, or output. Examples might include the following: lighting; heating, ventilation, and air conditioning; motors; transformers; vehicles; waste management; coal mining; and livestock management. Reporters should provide as much specificity as possible on the exact nature of the activities.

- Equipment affected – Reporters should indicate the number of pieces of equipment affected by the specific action. For example, reporters should provide the number of vehicles, transformers, or lights affected by the specific action. If the number of pieces of equipment changes, the reporter may continue to report using the same

subentity name, base period(s), and base-value emissions, but must calculate any reported reductions based on the equipment actually in use during the reporting year.

- Emissions source affected – Reporters should identify the source of emissions associated with the specific action taken. In many cases the source of emissions will not arise directly from the equipment affected by the action, but may occur elsewhere, such as from the entity's boiler or the entity's electricity consumption at a specific plant or facility. If the emission sources associated with the specific action change (e.g., power is purchased from a new dedicated facility or the boiler has been upgraded), base-year or base-period emissions should be restated to reflect the emissions intensity of the new emissions source.

### 2.4.5.2 Calculation of Action-Specific Emission Reductions

#### 2.4.5.2.1 Action-Specific Base Periods

Unless otherwise specified below, the base period from which base-value emissions and other performance characteristics are derived should be immediately prior to the year of the identified action.

#### 2.4.5.2.2 Action-Specific Base Values

Action-specific base values must be in one of two forms:

- Total emissions, total captured emissions (e.g., methane recovery from landfills or coal seams), or another fixed quantity that is directly translatable into emissions; or
- Derived emissions per unit of output or service (e.g., kilowatt-hours [kWh] per square foot of lighted space) based on technology or process use, or an intensity metric that is directly translatable into an emissions-intensity value.

The emissions and output quantities must be derived from the actual or estimated emissions of the process or technology extant in the entity's base year or base period. If measured data on actual emissions and output are not available, estimates based on the tested performance of the type of process or technology employed during the base year or base period may be used. For example, if the entity used incandescent lighting during the base year or base period, emissions may be estimated by multiplying the total rated wattage of the lights affected by the action by the estimated hours of operation of those lights. The resulting estimate of electricity (kWh) used would then be converted to emissions using the default emissions factor supplied by EIA, in accordance with these guidelines.

#### 2.4.5.2.3 Calculating Action-Specific Reductions

Action-specific emission reductions are derived by comparing the established base value to the comparable values for the reporting year.

If the base value is in the form of absolute emissions, emissions captured or other fixed quantity, reductions are calculated by comparing the base value to the comparable quantity for the reporting year, derived using the compatible measurement or estimation techniques. For example, emission reductions associated with landfill gas recovery are determined by comparing the amount of gas recovered in the base period to the amount of gas recovered in the reporting year for the same group of landfill operations.

If the base value is in the form of emissions intensity (or energy efficiency), reductions are calculated by comparing the base-value rate of emissions intensity to the comparable rate for the reporting year, then multiplying by the output value for the reporting year. For example, the efficiency of a lighting system before and after a technology change could be determined and the difference between those two rates calculated. The change in efficiency could then be multiplied by the hours of operation or other output measure in the reporting year to estimate the resulting emission reduction.

#### 2.4.5.3 Documenting Data Collection, Estimation, and Calculation Methods

All reports using action-specific methods must provide a summary description of all measurement, estimation, and calculation methods used to determine the reported emission reductions.

#### 2.4.5.4 Comprehensive Assessment of Emissions

Reporters must perform a comprehensive assessment of the direct and indirect effects on emissions of each specific action in each year for which reductions are being calculated. This includes the extent to which the specific action may increase emissions of alternative gases, or may increase emissions from other sources within the entity's control that are not directly affected by the specific action. Reporters should also note potential increases in emissions that will occur outside the entity's boundary as a result of the specific action.

#### 2.4.5.5 Continuous Reporting

As in the application of all other calculation methods, entities registering reductions from specific actions must continue to report annually on each such action. If a gap in annual reporting occurs, the entity must file reports for the missing year(s) prior to registering any further emission reductions.

#### 2.4.5.6 Specific Guidance for Certain Categories of Actions

DOE recognizes that there are a number of specific actions for which developing an estimate of base-period(s) emissions based on extant technology or process and base-period activity levels is not practical. For those specific actions we have provided the following guidance on establishing base-period(s) emissions and calculating reductions.

#### 2.4.5.6.1 Coalmine Methane Gas Recovery

Coalmine degasification may take several forms, including standard ventilation techniques, horizontal boreholes, gob wells, and pre-mining degasification. For standard ventilation techniques, horizontal boreholes, and gob wells, the DOE assumes that absent efforts for recovery, all methane flows would have been emitted to the atmosphere in the year they are recorded. Thus, for purposes of calculating action-specific reductions for the capture of methane emitted from active mines, base-period recovery, rather than base-period emissions, should be calculated. Total annual flows captured in the base period should be recorded and the average of the annual flows assigned as the base value. If no flows were captured in the base period, zero should be used as the base-value quantity. Average gas recovery in the base period should be subtracted from gas recovery in the reporting year to estimate methane reductions.

After capture, the disposition of the methane needs to be considered. If the captured methane was flared, then the increase in carbon dioxide emissions should be reported. If the methane was used to generate electricity, the carbon dioxide emissions associated with that generation should be compared to the benchmark provided in subsection 2.4.4.2.1, "Avoided Emission Benchmarks," above, to estimate the net effect on carbon dioxide emissions. If the captured gas is sold to a pipeline company or for direct use as a fuel, the reporter should assume that any changes in emissions will be captured by the consumer of the methane and that there will be no net change in the reporter's emissions as a result of this specific action. This calculation should be completed for the current year and the result compared to the average result of the same calculation for the years included in the base period to determine net carbon dioxide reductions from the disposition of recovered methane. This number should be added to the estimated methane reductions to yield the total net carbon dioxide equivalent reductions from capturing methane from standard ventilation systems, horizontal boreholes, and gob wells.

In the case of pre-mining degasification, DOE assumes that the methane flows would not have been liberated from the surrounding coal seam until the coal seam was cut through. Any reductions in methane emissions associated with pre-mining gasification should thus be estimated only for the year that the mine was cut through. Once a coal seam that underwent pre-mining degasification has been cut through, the methane captured may be added to the entity's recovery numbers. Similar to standard ventilation techniques, horizontal boreholes, and gob wells, reductions of methane from pre-mining degasification should be calculated by comparing total recovery in the current year to total recovery in the base period. Because sales of electricity generated from recovered methane, direct sales of methane, or methane flaring occur prior to and independent of coal mining, however, changes in carbon dioxide emissions associated with the disposition of recovered methane may be calculated using the avoided-emission techniques outlined in the paragraph above and aggregated with methane reductions achieved in the year that the coal seam is cut through.

DOE requires the following documentation to register emission reductions from coalmine degasification:

- The name and location of the coal mine or mines affected.
- The month and year in which the coal seam was cut through.

- Estimated quantity of emissions from ventilation systems and any gas captured from degasification systems that has been vented.
- The method of degasification (e.g., ventilation techniques, horizontal boreholes, gob wells, or pre-mining degasification).
- The current method of disposition for the recovered gas (flaring, sale for energy recovery).
- The volume of gas recovered in each year of the base period.
- The heat content or percent methane of the gas recovered in each year of the base period.
- The volume of gas recovered in the reporting year.
- The heat content or percent methane of the gas recovered in the current year.

#### 2.4.5.6.2 Landfill Methane Recovery

Landfill gas recovered and combusted through flaring or for conversion to energy represents a reduction in methane emissions. Gas vented should be reported as an emission in entity or subentity inventories. For purposes of calculating action-specific reductions from the capture and combustion of methane emitted from landfills, base-period gas recovery (reductions), rather than base-period emissions, should be calculated. The average of total annual flows captured and flared or sold for energy in each year of the base period should be reported as the base value. If no gas was captured and flared, used to generate electricity or sold for direct use in the base period, zero should be used as the base-value quantity. Average annual gas recovery in the base period should be subtracted from gas recovery in the reporting year to estimate methane reductions.

After capture, the disposition of the methane needs to be considered. If the captured methane was flared, then the increase in carbon dioxide emissions is biogenic and need not be reported. If the methane was used to generate electricity, the carbon dioxide emissions associated with that generation are biogenic, assumed to be zero for reporting purposes and the carbon dioxide reduction will be equal to the benchmark provided in subsection 2.4.4.2.1 multiplied by the amount of electricity generated. If the recovered methane was added to a natural gas supply network, or sold directly for use as a fuel, any changes in emissions will be captured by the consumer of the methane and there will be no net effect of emissions reported for this specific action. This calculation should be completed for the current year and the result compared to the average result of the same calculation for the years included in the base period to determine net carbon dioxide reductions from the disposition of recovered methane. This number should be added to the estimated methane reductions to yield the total net carbon dioxide equivalent reductions.

DOE requires the following documentation to register emission reductions from landfill gas recovery:

- Name and location of the landfill or landfills affected.
- Year of opening and closure (if applicable) for the landfill(s) affected.
- Estimated volume of waste in place for the landfill(s) affected.
- Measured or modeled quantity of emissions from the landfill(s) in the base year.
- Measured or modeled quantity of emissions from the landfill(s) in the current year.

- Year of installation of the gas recovery system.
- The volume of gas recovered in the reporting year.
- The heat content or percent methane of the gas recovered in the current year.
- The current method of disposition for the recovered gas (flaring, electricity generation, sale to the natural gas supply network, or direct use)
- The Btus of gas used to generate electricity or sold to the natural gas supply network or for direct use.
- The volume of gas recovered in each year of the base period.
- The heat content or percent methane of the gas recovered in each year of the base period.
- The method of disposition for the recovered gas (flaring, electricity generation, sale to the natural gas supply network, or direct use) in each year of the base period
- The Btus of gas used to generate electricity, sold to the natural gas supply network, or used directly in each year of the base period.

#### 2.4.5.6.3 Capture of Methane from Anaerobic Digestion at Wastewater Treatment Facilities

When wastewater is treated under anaerobic conditions, the decomposition of its organic portion yields methane. Like methane generated from waste at landfills, the methane generated from wastewater treatment may be captured and either flared or used as an energy resource. Because captured methane has value as an energy resource, operators may use an anaerobic digester to treat the wastewater and maximize methane generation.

For purposes of calculating action-specific reductions from the capture and combustion of methane emitted from waste treatment facilities, base-period gas recovery (reductions), rather than base-period emissions, should be calculated. Average total annual flows captured and flared or sold for energy in the base period should be reported as the base value. If wastewater was treated aerobically during the base period, no reductions of methane may be reported, though entities may calculate changes in indirect emissions from electricity generated and used on-site or avoided emissions from the sale of electricity generated from recovered methane in accord with the Section 2.4.4 of these Technical Guidelines. If wastewater was treated anaerobically and no gas was captured and flared or sold for energy recovery during the base period, zero should be used as the base-value quantity. Gas recovered in the base period should be subtracted from gas recovery in the reporting year to estimate methane reductions. If wastewater was treated aerobically during the base period, the introduction of an anaerobic digester may increase nitrous oxide emissions and these increases should be quantified.

After capture, the disposition of the methane needs to be considered. If the captured methane was flared, then the increase in carbon dioxide emissions is biogenic and need not be reported. If the methane was used to generate electricity, the carbon dioxide emissions associated with that generation are biogenic, assumed to be zero for reporting purposes and the carbon dioxide reduction will be equal to the benchmark provided in subsection 2.4.4.2.1 multiplied by the amount of electricity generated. If the recovered methane was added to a natural gas supply network, or sold directly for use as a fuel, any changes in emissions will be captured by the consumer of the methane and there will be no net effect of emissions reported for this specific action. This calculation should be completed for the current year and the result compared to the

average result of the same calculation for the years included in the base period to determine net carbon dioxide reductions from the disposition of recovered methane. This number should be added to the estimated methane reductions to yield the total net carbon dioxide equivalent reductions.

DOE requires the following documentation to register emission reductions from wastewater treatment facilities:

- Name and location of the wastewater treatment facility(ies) affected.
- Measured or modeled quantity of emissions from the wastewater treatment facility in the each year of the base period.
- Measured or modeled quantity of emissions from the wastewater treatment facility in the current year.
- The volume of gas recovered in the reporting year.
- The current method of disposition for the recovered gas (flaring, electricity generation, sale to the natural gas supply network, or direct use).
- The Btus of gas used to generate electricity, sold to the natural gas supply network, or used directly.
- The volume of gas recovered in each year of the base period.
- The method of disposition for the recovered gas (flaring, electricity generation, sale to the natural gas supply network, or direct use) in each year of the base period.
- The Btus of gas used to generate electricity, sold to the natural gas supply network, or used directly in each year of the base period.

#### 2.4.5.6.4 Capture of Methane from Anaerobic Digestion of Animal Waste

When animal waste decomposes under anaerobic conditions such as liquid/slurry in lagoons, ponds, tanks, or pits, methane is produced. This methane may be captured and either flared or used as an energy resource. Because captured methane has value as an energy resource, operators may use an anaerobic digester to treat the animal waste and maximize methane generation.

For purposes of calculating action-specific reductions from the capture and combustion of methane emitted from animal waste decomposition, base-period gas recovery (reductions), rather than base-period emissions, should be calculated. Average total annual flows captured and flared or sold for energy in the base period should be reported as the base value. If animal waste was handled as a solid, or deposited on pasture, range, or paddock lands to decompose aerobically during the base period, no reductions of methane may be reported, though entities may calculate changes in indirect emissions from electricity generated and used on-site or avoided emissions from the sale of electricity generated from recovered methane in accord with the Section 2.4.5.6.2 of these Technical Guidelines. If animal waste was handled under anaerobic conditions and no gas was captured and flared or sold for energy recovery during the base period, zero should be used as the base-value quantity. Gas recovered in the base period should be subtracted from gas recovery in the reporting year to estimate methane reductions. If animal waste was handled under aerobic conditions during the base period, the introduction of an anaerobic digester may increase nitrous oxide emissions, and these emissions should be quantified.

After capture, the disposition of the methane needs to be considered. If the captured methane was flared, then the resulting increase in carbon dioxide emissions are biogenic and need not should be reported. If the methane was used to generate electricity that was used on-site, the reporter may report reductions equal to the amount of electricity used multiplied by the indirect carbon dioxide emissions benchmark. Similarly if the electricity generated was sold off-site, the emissions associated with that generation should be treated as zero and compared to the benchmark provided in subsection 2.4.4.2.1, "Avoided Emission Benchmarks," above, to estimate the net effect on carbon dioxide emissions. If the recovered methane was added to a natural gas supply network, or sold directly for use as a fuel, any changes in emissions will be captured by the consumer of the methane and there will be no net effect of emissions reported for this specific action. This calculation should be completed for the current year and the result compared to the average result of the same calculation for the years included in the base period to determine net carbon dioxide reductions from the disposition of recovered methane. This number should be added to the estimated methane reductions to yield the total net carbon dioxide equivalent reductions.

DOE requires the following documentation to register emission reductions from the capture of methane from the anaerobic digestion of animal waste:

- Name and location of livestock management facility(ies) affected.
- Modeled quantity of emissions from animal waste decomposition in the each year of the base period.
- Modeled quantity of emissions from animal waste decomposition in the current year.
- Number and species of animals producing waste handled by the livestock management facility(ies) affected.
- The volume of gas recovered in the reporting year.
- The current method of disposition for the recovered gas (flaring, electricity generation, sale to the natural gas supply network, or direct use)
- The Btus of gas used to generate electricity, sold to the natural gas supply network, or used directly.
- The volume of gas recovered in each year of the base period.
- The method of disposition for the recovered gas (flaring, electricity generation, sale to the natural gas supply network, or direct use) in each year of the base period
- The Btus of gas used to generate electricity, sold to the natural gas supply network, or used directly in each year of the base period.

#### 2.4.5.6.5 Geologic Sequestration

There are a significant number of variables that will affect calculation of emission reductions from geologic sequestration. The following basic principles must be applied when calculating reductions:

- Geologic sequestration may be used to store carbon dioxide from naturally occurring reservoirs or from anthropogenic industrial or energy-combustion sources. Carbon dioxide that was produced by an anthropogenic process that would have otherwise led to its release into the atmosphere may be used in an emission reductions calculation. Carbon

dioxide removed from natural reservoirs for the sole purpose of aiding enhanced oil or other energy recovery may only be used for registered reductions if the extracted carbon dioxide is treated as an emission in the entity's inventory.

- The capture and sale of anthropogenic carbon dioxide does not, in itself, yield a reduction; it is only through long-term storage of carbon dioxide that a reduction may be generated. For the purpose of calculating emission reductions, all sales or other transfers of carbon dioxide to another entity must be treated as emissions in the year of the transfer. Entities that capture and sell carbon dioxide to a third party that permanently sequestered the carbon dioxide by injecting it into geologic formations may report reductions only if there is a written agreement with the third party.

- Entities that purchase carbon dioxide for the purpose of injecting it into geologic formations must report any difference between the volume of gas purchased and the amount sequestered in a geologic formation. Such entities may only register net increases in the volume of gas being sequestered.

- Captured carbon dioxide that is injected into a suitable geologic formation for permanent storage may be considered sequestered once it has been stored in a sealed geologic reservoir and any fugitive emissions during the injection process have been subtracted; that is, the amount of sequestration is equal to the quantity of carbon dioxide injected less emissions leaked during the storage process. Potential source of leakage include: 1) any carbon dioxide dissolved or entrained in the water and oil produced from an enhanced oil recovery project and the resulting emissions, and 2) any carbon dioxide leaked from the injection wells during the storage process before the wells have been permanently sealed. Monitoring equipment should be installed at all the injection wells to track any of these emission sources.

- Captured carbon dioxide used for enhanced oil recovery will likely return to the atmosphere over a period of 10 to 30 years, unless the injection wells are sealed to avoid future releases. The reporter must seal, or plan to seal, the injection wells at the completion of the project to claim reductions. Operators of enhanced oil recovery sites that will not be sealed cannot claim reductions for any carbon dioxide injected.

- Even if the wells are sealed it is possible that some amount of carbon dioxide will escape to the atmosphere in the future. Long-term carbon dioxide seepage from the injection wells and the storage site is also possible in the case of storage projects created specifically with the purpose of isolating carbon dioxide from the atmosphere. To register reductions, the reporter must determine the amount of carbon dioxide leaked back to the atmosphere using one of the following two monitoring options:

    - Actively monitor and maintain the geologic formation used, measuring actual carbon dioxide losses from the well heads and the storage reservoir, which would then be treated as emissions in the year in which they occur. These emissions are the responsibility of the same entity which claims the rights to the reductions achieved through the geologic sequestration activity. Applicable monitoring

methods are described in Section 1.G.7. The reporter may use any of the described monitoring methods that are rated "A" or "B."

- Apply a monitoring plan already approved by a relevant Federal or state regulatory agency for the purpose of tracking carbon dioxide seepage/leakage.

Like coal mine degasification and landfill methane recovery, reductions should be calculated by comparing current-year sequestration to sequestration levels in the base period. Reductions are equal to the net change in sequestration levels.

DOE requires the following documentation to register emission reductions from geologic sequestration:

- Name and location of the source of the carbon dioxide.
- Method of disposition for the carbon dioxide (e.g., long-term geologic storage or enhanced oil recovery).
- Name and location of the geologic formation or other sink used to sequester the carbon dioxide.
- Year of capture and permanent sequestration.
- Volume of carbon dioxide captured or transferred to the entity.
- Volume of carbon dioxide permanently sequestered less leakage during the storage process.
- The method used to estimate net sequestration (e.g., Federal/state or new life-cycle analysis or active monitoring approach).
- Estimated volume permanently sequestered in the base year.
- Estimated volume permanently sequestered in the current reporting year.

#### 2.4.5.6.6 Transmission and Distribution Improvements

The transmission and distribution of electricity does not in itself generate emissions. Rather, inefficiencies in the transmission and distribution (T&D) system result in "losses" between the amount of electricity generated and the amount delivered to an end user, requiring that incremental electricity (an amount equal to the losses) be generated to meet the end-user's demand. T&D system operators can reduce these losses by making physical improvements to the system or implementing operational changes. For purposes of calculating emission reductions from transmission and distribution improvements (operational or physical), base-year emissions are equal to the system-wide volume of line losses multiplied by a factor for emissions from electricity generation.

The reporting entity, whether a utility, independent transmission company, regional transmission organization (RTO) or other company or institution, should exercise sufficient financial or other control over the covered transmission and distribution system to include this system within their entity's organizational boundary. A claim of loss reduction might be made by 1) an regional transmission organization (RTO) based on improvements in dispatch or system operations; 2) an independent transmission company – which may be part of an RTO – based on changes in system operations or physical upgrades; 3) a control area (typically a larger transmission owning

utility) – which may be part of an RTO and in some cases also part of an independent transmission company – based on changes in dispatch, system operations, or physical upgrades; or 4) a non-control area transmission and/or distribution owning utility – which may be part of an RTO and in some cases the system of an independent transmission company and will be part of a larger control area – based on changes in operations or physical upgrades. The reporting entity's assessment of losses must cover all of the transmission and distribution system included within its organization boundary.[184] If the entity making the filing is part of a larger entity or is composed of smaller entities, it must coordinate its filing with these other entities to ensure that there is no double counting.

Entities can calculate emission reductions achieved by reducing T&D loss intensity by following the steps below (note: because of annual variations in T&D system losses attributable to changes in weather and loads, DOE recommends that entities calculate base period T&D loss ratios for multi-year base periods). Reductions in T&D losses may be reported in either kWh or kilovolt-ampere hours (kVAh). Reporters must choose whether to measure impacts related to reductions in T&D losses in either kWh or kVAh and consistently report all loss impacts in the selected unit of measurement.

Step 1: Calculate T&D Loss Ratios

Calculate base period and current year T&D loss ratios using the following equation:

$$LR = (G + I_n - D)/(G + I_n)$$

**Where:**

| | | |
|---|---|---|
| **LR** | **=** | **loss ratio** |
| **G** | **=** | **electricity entering T&D system from generation** |
| **D** | **=** | **amount of electricity delivered to end users** |
| **$I_n$** | **=** | **net imports of electricity (total imports less total exports)**[185] |

If a reporter elects to report on a control area basis, the base period and current year transmission and distribution loss ratios should be calculated using the following equation:

$$LR = (G - (D + ANI))/(G - ANI)$$

**Where:**

| | | |
|---|---|---|
| **LR** | **=** | **loss ratio** |
| **G** | **=** | **electricity entering T&D system from generation** |

[184] The reporting entity must use substantially the same organizational boundary to define the relevant transmission and distribution system when presenting calculations for both its based period and the current year.
[185] The calculation of net imports should include, but is not limited to, power received from and delivered to independent distribution companies that may be physically located within the footprint of the reporting entities transmission system.

| | | |
|---|---|---|
| **D** | **=** | **amount of electricity delivered to end users**[186] |
| **ANI** | **=** | **Actual Net Interchange**[187] **for the control area or member control areas, from the net generation received into the system** |

Step 2: Calculate Net Change in Loss Intensity

The following equation should be used to calculate the net change in loss intensity:

$$LI = (LR_B - LR_C) * (G + I_n)$$

**Where,**

| | | |
|---|---|---|
| **LI** | **=** | **change in loss intensity** |
| $LR_B$ | **=** | **base period loss ratio** |
| $LR_C$ | **=** | **current year loss ratio** |
| **G** | **=** | **electricity entering T&D system from generation** |
| $I_n$ | **=** | **net imports of electricity (total imports less total exports)** |

If reporting on a control area basis, use the following equation to calculate the change in loss intensity:

$$LI = (LR_B - LR_C) * (G - ANI)$$

**Where:**

| | | |
|---|---|---|
| **LI** | **=** | **change in loss intensity** |
| $LR_B$ | **=** | **base period loss ratio** |
| $LR_C$ | **=** | **current year loss ratio** |
| **G** | **=** | **electricity entering T&D system from generation** |
| **ANI** | **=** | **Annual Net Interchange for the control area or member control areas** |

Step 3: Calculate Emission Reduction

If the change in loss intensity was calculated in kWh, use the following equation to estimate the associated emission reduction:

$$R = LI * B$$

[186] Include both electricity delivered directly to end users by the reporting entity and, to the extent not included in the calculation of "actual net interchange", power delivered to independent distribution companies physically located within the reporting entity's control area for delivery by such independent distribution companies to their end users.

[187] Actual net interchange is positive for power leaving the system and negative for power entering.

**Where:**

| | | |
|---|---|---|
| **R** | **=** | **emission reduction** |
| **LI** | **=** | **change in loss intensity** |
| **B** | **=** | **emissions benchmark provided above in subsection 2.4.4** |

If the change in loss intensity was calculated in kVAh, use the following equation to estimate the associated emission reduction:

$$R = LI * (B * PF)$$

**Where:**

| | | |
|---|---|---|
| **R** | **=** | **emission reduction** |
| **LI** | **=** | **change in loss intensity** |
| **B** | **=** | **emissions benchmark provided above in subsection 2.4.4** |
| **PF** | **=** | **system power factor for the current year** |

The power factor of an alternating current electric power system is defined as the ratio of the real power measured in Watts to the apparent power measured in volt-amperes. If the power factor (PF) for the entity's T&D system is known and publicly reported outside of the 1605(b) Program, it may be used in this calculation provided it does not exceed 0.95. If the known and publicly reported system power factor exceeds 0.95, the reporter must use a power factor of 0.95. If the system power factor is unknown or not reported publicly, the reporter should use a default of 0.90 in to calculate the emission reduction.

The resulting quantity is the emission reduction (or increase) attributable to changes in transmission and distribution losses that should be incorporated in the entity's report to DOE.

DOE requires the following documentation to register reductions from transmission and distribution losses:

- Total estimated number of kWh or kVAh entering the transmission and distribution system from generation in the base period.
- Total estimated number of kWh or kVAh delivered from the transmission and distribution system to end users and, if reporting on a control area basis, to independent distribution companies within the entity's control area or member control areas in the base period.
- Total estimated net exports leaving (positive number) or net imports entering (negative number) the transmission and distribution system in the base period. If an entity is reporting on a control area basis, the net exports or imports should be reported on the basis of the Actual Net Interchange for the control area or member control areas in the base period.
- Total estimated number of kWh or kVAh entering the transmission and distribution system from generation in the current year.

- Total estimated number of kWh or kVAh delivered from the transmission and distribution system to end users and, if reporting on a control area basis, to independent distribution companies within the entity's control area or member control areas in the current year.
- Total estimated net exports leaving (positive number) or net imports entering (negative number) the reporting entity's transmission and distribution system in the current year. If the report is filed on a control area basis, the net exports or imports should be reported on the basis of the Actual Net Interchange for the control area or member control areas in the current year.
- If reporting changes in losses in kVAh and on the basis of a known power factor, the calculation of the system power factor utilized for reporting purposes.
- Description of specific actions taken to reduce losses from the transmission and distribution system (e.g., high-efficiency transformers, reconductoring, distribution voltage upgrade).

#### 2.4.5.6.7 Recycling of Fly Ash

Fly ash from the combustion of coal can be used as a substitute for Portland cement in concrete, which reduces emissions associated with the manufacture of the displaced cement. The key step in producing Portland cement is calcination, in which calcium carbonate ($CaCO_3$) is heated in a kiln to a temperature of approximately 1,300°C (2,400°F). This reduces the calcium carbonate to lime (CaO) and releases carbon dioxide to the atmosphere. Lime is combined with silica containing materials to produce and intermediate product called clinker, which is allowed to cool. A small amount of gypsum is added to the clinker to produce the final Portland cement product. This process requires substantial amounts of energy, largely for calcination, that is provided by the combustion of fossil fuels, which results in additional emissions of carbon dioxide.

Concrete manufacturers that replace Portland cement with fly ash are permitted to report the resulting indirect emission reductions using this action-specific method. Other entities, including electric generators that produce fly ash in coal-fired power plants, may report indirect reductions resulting from the transfer of fly ash to concrete manufacturers under the offset provisions described in §300.7(d) of the General Guidelines.

The U.S. Environmental Protection Agency (EPA) has prepared a life-cycle assessment of greenhouse gas emissions of fly ash used as a substitute for Portland cement in concrete.[188] DOE has used the spreadsheet version of EPA's WAste Reduction Model (WARM)[189] to estimate a coefficient for the net emission reductions for using fly ash in concrete, which compares this practice with landfill disposal of fly ash. The resulting coefficients are presented in Table 2.3.

[188] U.S. Environmental Protection Agency, Background Document for Life-cycle Greenhouse Gas Emission Factors for Fly Ash Used as a Cement Replacement in Concrete, EPA530-R-03-016, November 7, 2003.
[189] U.S. Environmental Protection Agency, WAste Reduction Model (WARM), Version 6 (December 8, 2004), http://yosemite.epa.gov/oar/globalwarming.nsf/content/ActionsWasteWARM.html.

**Table 2.3 Coefficients for Net Emission Reductions for Use of Fly Ash as a Substitute for Portland Cement in Concrete**

| Emission Reduction (Metric tons $CO_2E$) | Per Unit of Fly Ash Used in Concrete |
|---|---|
| 0.91 | Short Ton |
| 1.00 | Metric Ton |

Source: U.S. Environmental Protection Agency, WAste Reduction Model (WARM), Excel® spreadsheet model, Version 6, December 8, 2004.

To calculate the indirect emissions displaced in metric tons of carbon dioxide equivalent through the use of fly ash as a substitute for Portland cement in concrete, multiply the quantity (in short tons or metric tons) of fly ash used by the appropriate coefficient in Table 2.3. Emission reduction resulting from this practice should be calculated using the following equations:

$$BV = (E_B/Y_B)$$

$$R_{RY} = BV - E_{RY}$$

**Where:**

**BV = base value (in metric tons $CO_2E$)**

**$E_B$ = sum of emissions displaced by use of fly ash in concrete in base period (in metric tons $CO_2E$)**

**$Y_B$ = number of years in base period**

**$R_{RY}$ = emission reduction for fly ash used in concrete in reporting year (in metric tons $CO_2E$)**

**$E_{RY}$ = emissions displaced by fly ash used in concrete in reporting year (in metric tons $CO_2E$)**

### 2.4.5.6.8 Destruction of Chlorofluorocarbons

Chlorofluorocarbons (CFCs) can be used as refrigerants, blowing agents, and solvents. The production and use of these gases is being phased out under the Montreal Protocol on Substances that Deplete the Ozone Layer, which came into force in 1989. In addition to destroying ozone, CFCs are also powerful greenhouse gases. However, the direct positive radiative forcing of CFCs are offset by indirect negative radiative forcing due to their roles in the destruction of atmospheric ozone and methane, both of which are greenhouse gases. Because these indirect radiative forcing effects are difficult to quantify, the IPCC has not established single point net global warming potentials (GWPs) for these gases, although it has estimated a range for the net GWP for three gases (CFC-11, CFC-12, and CFC-113).[190] Because of the uncertainty regarding their radiative forcing effects and their regulation under the Montreal Protocol, the parties to the Kyoto Protocol excluded CFCs from the greenhouse gases to be controlled. However, Section 1605(b)(1) of the Energy Policy Act of 1992 explicitly directed DOE to "establish procedures for

[190] Intergovernmental Panel on Climate Change, *Climate Change 2001: The Scientific Basis*. (2001), Cambridge University Press, pp. 390-391.

the accurate voluntary reporting of information on…chlorofluorocarbon capture and replacement."

Over time, the CFCs used as the working gas in refrigeration and air conditioning systems leak to the atmosphere and must be replaced. In some circumstances, usually requiring some equipment modifications, CFCs can be recovered and replaced by non ozone-destroying gases, such as hydrofluorocarbons (HFCs). Also, when the systems are retired, however, a certain amount of working gas is retained and can be captured by scrap merchants that process used refrigeration or air conditioning units. The recovered CFCs can either be recycled for use in systems that still use CFC refrigerants or destroyed. Because some portion or all of recycled CFCs ultimately will be released to the atmosphere through leaks from refrigeration and air-conditioning equipment, DOE is permitting the reporting of CFC reductions only where the gas is captured and destroyed. The entity responsible for destruction of a CFC may report, separately, the quantity of a given gas destroyed in any calendar year as a reduction, but such reductions must not be included in the entity's emission inventories or net emission reduction calculations.

Owing to the uncertainty regarding their GWPs, reductions of CFCs must be reported in units of native gas (e.g., kilograms or metric tons of CFC-12) rather than in units of carbon dioxide equivalent (e.g. $MTCO_2E$).

#### 2.4.5.6.9 Demand-side management or other emission reduction programs

The incremental annual emission reductions that have been independently verified to be attributable to the effects of qualifying demand-side management (DSM) or other programs may be reported and registered as an offset reduction, if the reporting entity has met all other requirements for registration. To qualify, the DSM or other program must be funded by the reporting entity and the estimated effects reported must first occur after the entity's start year and must cause a reduction of the total emissions of residential or other very small emitters (entities that typically emit below 500 tons of carbon dioxide equivalent per year of greenhouse gases and are therefore highly unlikely to be reporting entities under these guidelines). Qualifying programs must provide information or other technical assistance, financial incentives, direct installation or investment, or other non-commercial services to very small emitters to assist them in achieving emission reductions recognized by these guidelines. In this context, "non-commercial" means that the service may not charge participants fees that are sufficient to cover the costs of the program.

The emission reductions reported should: 1) reflect only the effects of actions that are undertaken after the entity's start year specifically in response to entity-administered programs, including program activities implemented by third parties under contract to the entity; and 2) be calculated based on the energy (e.g., kWh of electricity, thousand cubic feet of natural gas) effects at the customer meter or other measures of the changes in greenhouse gas emissions or carbon stocks of the very small emitters affected. The reduction estimates must exclude, to the extent possible, energy or other emission effects that are not attributable to the identified program activities. Non-program related effects must be excluded, including changes in energy use or emissions attributable to: 1) free riders (i.e., program participants that would have adopted program-

recommended actions even without the program); 2) government-mandated energy-efficiency standards that legislate improvements in building and appliance energy usage; 3) natural operations of the marketplace (e.g., reductions in customer energy usage due to higher prices or reductions achieved by non-participants that were not attributable to the effects of the program); and 4) weather and business-cycle fluctuations. Power supply cooperatives, municipal joint action agencies, and Federal Power Marketing Administrations must coordinate the reporting of DSM information with their power purchasing utilities to avoid double counting the effects of DSM programs.

Estimates of the annual energy usage reductions attributable to qualified DSM or other programs must be based on program evaluations that are capable of reliably distinguishing between program effects and non-program-related effects, and capable of estimating how program-related effects are likely to diminish over time. Acceptable program evaluations may require statistically valid surveys or energy use metering of program participants and non-participants. Entity reports must include a summary description of the DSM efficiency or other program, the very small emitters that are the primary target of the program, and the program evaluation methodology.

Program evaluations must be performed and/or certified by an independent and qualified third party verifier. An independent third-party may not be owned in whole or part by the reporting entity, nor may it provide any ongoing operational or support services to the entity, except services consistent with independent financial accounting or independent certification of compliance with government or private standards. To be qualified, the third-party must have experience in conducting or assessing statistically-valid program impact evaluations recognized by government agencies. Responsible government regulatory agencies are considered to be both independent and qualified third party verifiers. The independent third party and its qualifications must be identified in the entity's report and the third party must certify that the estimated annual energy usage or emission reductions were estimated in accordance with these guidelines. Estimated annual energy usage reductions should be converted to greenhouse gas emissions using the appropriate end-use emissions factors, specified elsewhere in these guidelines.

## 2.4.6 Estimating Reductions Associated with Energy Exports

Avoided emissions occur when an energy product, including electricity, hot water, steam, and cooling, produced by a non- or low-emitting source is sold (exported) to a customer that would have otherwise purchased a comparable energy product generated by a higher-emitting source. Producers of electricity, steam, and hot or chilled water must use this method coupled with the Changes in Emissions Intensity method (see subsection 2.4.1) to calculate the emission reductions associated with any increases in the quantity of energy they have generated for distribution to other entities or users, as described below.

### 2.4.6.1. Estimating Reductions from Energy Generation and Distribution

Energy generators, including electricity generators and thermal generators of steam, heating, and cooling, that sell or distribute all or some portion of the energy they generate are potentially eligible for reporting emission reductions. The methods described below should be used only to

estimate emission reductions associated with electricity, heat or cooling that were exported outside of an entity's boundaries. Emissions associated with power that was generated and used within an entity's (or subentity's) boundaries, including energy from small electricity generators or boilers, should be factored into the entity's (or subentity's) estimate of the emissions intensity of its product output for the reporting year. In contrast, emissions associated with energy that was sold or otherwise exported outside of the generator's entity (or subentity) boundaries are not included in estimates of the emissions intensity of the entity's (or subentity's) product output, but should be included in a separate subentity report.

In general, emission reductions are intended to recognize actions that contribute to reducing the energy intensity of the U.S. generating sector on the whole. For energy generators, these actions can be categorized into two types: those that reduce the emissions intensity of an entity's own generation, and those that reduce demand for other, more emitting sources (avoided emissions). Reporters should follow five steps to estimate emission reductions associated with exported power:

1. Estimate total generation and emissions for each energy type.
2. Distinguish between energy used internally versus exported.
3. Estimate reductions from exported energy due to improvements to historical emissions intensity.
4. Estimate reductions from exported energy associated with incremental changes in generation.
5. Calculate total reporting year reductions from exported energy.

**Step 1: Estimate total generation and emissions for each energy type**

The total quantities of power generation and associated emissions should be estimated for each type of energy generated. Methods for estimating emissions from power generation can be found in the Inventory Chapter (Chapter 1) of the Technical Guidelines.

**Step 2: Distinguish between energy used internally versus exported**

Reporters must track the quantities of electrical and thermal energy that are used within entity (or subentity) boundaries versus exported outside of the entity (or subentity) boundaries. For entities that sell some portion of their thermal or electrical generation, sales data and records will be the most easily referenced source of this information. Any power that is not exported can be assumed to be used internally. In cases where the output of a single generating unit is split into internal use and power exports, emissions must be allocated to internal use and exports based on the quantities used internally and exported:

**(Exported Generation / Total Generation) * Total Emissions= Exported Emissions**

**Step 3: For each type of energy exported, estimate reductions from energy exports due to improvements to historical emissions intensity**

Reductions that result from changes to an entity's emissions intensity are calculated by multiplying the difference between an entity's Base Year and Reporting Year emissions intensity

by the quantity of energy generated in the Base Period (after accounting for acquired and divested capacity, see Section 2.4.1, above):

$$\textbf{Reductions}_{\text{Base Generation}} = (E_B/O_B) - (E_R/O_R) * \text{Total Exported Generation}_B \text{ (MWh or MMBtu)}$$

**Where:**

| | | |
|---|---|---|
| **E** | **=** | **greenhouse gas emissions (in tons)** |
| **O** | **=** | **output measure (in selected measure)** |
| **E/O** | **=** | **GHG intensity** |
| **B** | **=** | **base period** |
| **R** | **=** | **reporting year.** |

### Step 4: For each type of energy exported, estimate reductions from energy exports associated with incremental changes in generation

Any change in the quantity of exported energy from the Base Period to the Reporting Year is considered "incremental," and is used to calculate the avoided emissions resulting from the associated change in demand on other generators. These reductions are calculated by multiplying the quantity of Incremental Generation by the difference between an entity's Reporting Year emissions intensity and the appropriate Benchmark emissions value:

> **Benchmark Values**
>
> Benchmark emissions values represent the typical emissions profile of the energy generation avoided by an entity's own generation. To represent avoided emissions, DOE will specify the use of values derived from average, nationwide emissions intensity for electricity or thermal generators. For more information, refer to "Avoided emissions benchmark(s) and indirect emissions conversion factors", below.

$$\textit{Reductions}_{\textit{Incremental}} = (\textit{Benchmark Intensity} - (E_R/O_R)) * \text{Incremental Generation (MWh or MMBtu)}$$

**Where:**

| | | |
|---|---|---|
| **E** | **=** | **greenhouse gas emissions (in tons)** |
| **O** | **=** | **output measure (in selected measure)** |
| **(E/O)** | **=** | **GHG intensity** |
| **R** | **=** | **reporting year** |

### Step 5: Calculate total reporting year reductions for exported energy

Total reductions can be calculated by adding the results of steps 3 and 4, above. Alternatively, any entity can calculate their Total Reporting Year Emission Reductions by using the following integrated formula (note: this formula may be used even if the entity did not generate energy in its base period):

$$\text{Emission Reductions}_{\text{Reduction Year}} = \text{'Exported' Emissions}_{\text{Base period}} + [\text{Incremental Generation} * \text{Benchmark}] - \text{'Exported' Emissions}_{\text{Reduction Year}}$$

**Where:**

| | | |
|---|---|---|
| **Benchmark** | **=** | **DOE-determined emissions intensity value for energy generation (tons $CO_2$ / MWh or tons $CO_2$ / MMBtu)** |
| **Emission Reductions$_{Reduction\ Year}$** | **=** | **Emission Reductions reportable during the reporting year (tons $CO_2$)** |
| **Incremental Generation** | **=** | **Increase in generation during the Reduction Year, relative to the Base period (MWh or MMBtu)** |
| **'Exported' Emissions$_{Base\ period}$** | **=** | **Total emissions associated with power exports in the Base period (tons $CO_2$)** |
| **'Exported' Emissions$_{Reduction\ Year}$** | **=** | **Total emissions associated with power exports in the Reduction Year (tons $CO_2$)** |

### 2.4.6.2. Estimating Emission Reductions from Renewable and Waste-to-energy Generation

Under the original 1605(b) Program, all types of energy generation, including renewable generation (e.g. biomass generation, solar, wind, hydro) and waste-to-energy generation (e.g., waste oil burning, tire and tire product burning, municipal waste burning and landfill gas generation) are treated equally with respect to calculating emission reductions. Reporters should refer to the following sections of the Inventory Chapter of the Technical Guidelines for guidance on estimating emissions from different types of energy generation:

- Part C, "Stationary Combustion:" Petroleum-based waste and byproduct fuels (e.g. tires, waste oil), biogenic fuels (e.g. bagasse, wood, wood waste, ethanol), municipal solid waste

- Part E, "Industrial Processes:" Coalmine methane, landfill methane, wastewater sludge and methane

- Part F, "Indirect Emissions:" Renewables

### 2.4.6.3. Estimating Emission Reductions from CHP Generators

Combined Heat and Power (CHP, also known as cogeneration) refers to a broad class of generators that simultaneously produce electricity and useful thermal energy, which can be used as process heat, to produce steam, to drive absorption chillers, or for a variety of other heating and chilling purposes.

While manufacturers use some 90 percent of the CHP systems in the United States, CHP plants vary widely in their size, fuel sources, and application. Although CHP generators are particularly well suited to processes that have a concurrent demand for thermal and electrical energy, it is common for CHP operators to sell some portion of their thermal or electrical generation if it is in

excess of their demand load. In some cases, CHP plants are operated exclusively as merchant plants, where both of the energy outputs are sold in their entirety. While the scale and the relative proportions of heat and electricity sold or used on-premises may vary, CHP generators fall into one of the following arrangements:

- Operator uses all heat and electricity on premises.
- Operator uses all heat on premises, sells all or some portion of electricity.
- Operator uses all electricity on premises, sells all or some portion of heat.
- Operator uses some portion of heat and electricity on premises, sells remaining.
- Operator sells all heat and all electricity off-premises.

**Reducing Emissions with CHP**

Entities that utilize CHP generators can achieve emissions reductions in two ways- by creating Avoided Emissions, or by reducing their entity-wide emissions intensity. Generators that export power for use outside of their entity boundaries can create Avoided Emissions if they increase exports relative to their Base Year. In contrast, emissions from power that is consumed within entity boundaries are factored into the reporting year estimate of product output emissions intensity. Due to its high fuel use efficiency, installing a CHP generator to meet on-site demands will typically reduce emissions relative to conventional sources. The resulting intensity-based reductions to entity-wide emissions may be direct, as in the case of replacing a boiler, or indirect, as in the case of reducing electricity purchases.

Emission reductions for CHP generators are calculated in the same manner as they are for conventional generators. Due to the fact that CHP generates multiple energy streams from a single fuel, and the variety of possible internal use/export arrangements, however, CHP operators must perform the additional step of allocating overall plant emissions to thermal and electrical generation before calculating reductions. This is accomplished in the two steps outlined below: first allocating fuel consumption to each generating stream, and then converting fuel consumption to emissions. Once emissions have been calculated for each generating stream, reductions should be calculated using the methods described under 'Estimating Reductions Associated with Energy Generation and Exports,' above.

### 2.4.6.3.1. Allocate Fuel Consumption to Thermal and Electrical Generation Streams

The first step in allocating emissions to electrical and thermal generation is to determine the fuel consumed by each process. The following formula allocates fuel consumption based on the efficiency of thermal generation and the assumption that any remaining fuel consumption is used for electricity generation:[191]

$$\text{Fuel use}_{\text{Thermal}} = \text{Output}_{\text{Thermal}} / \text{Efficiency}_{\text{Thermal}}$$

$$\text{Fuel use}_{\text{Electricity}} = \text{Fuel use}_{\text{Total}} - \text{Fuel use}_{\text{Thermal}}$$

**Where:**

| | | |
|---|---|---|
| **$\text{Efficiency}_{\text{Thermal}}$** | **=** | **Efficiency of thermal energy generation, expressed as a decimal percentage** |

[191] Method taken from: U.S. Energy Information Administration. *Annual Energy Review 2001* (November 2002), p. 370.

| | | |
|---|---|---|
| **Fuel use$_{Thermal}$** | **=** | **Fuel consumption attributable to thermal generation, measured in MMBtu** |
| **Fuel use$_{Electricity}$** | **=** | **Fuel consumption attributable to electricity generation, measured in MMBtu** |
| **Fuel use$_{Total}$** | **=** | **Total fuel consumption of CHP plant, measured in MMBtu** |
| **Output$_{Thermal}$** | **=** | **Thermal generation, measured in MMBtu** |

If the efficiency of thermal energy generation (Efficiency$_{Thermal}$) is unknown, reporters may use a default value of 0.8.

#### 2.4.6.3.2. Convert Fuel Use to Emissions

Reporters should refer to Part C of the Inventory Chapter of the Technical Guidelines, "Stationary Combustion," for guidance on how to convert fuel use to emissions.

#### 2.4.6.3.3. Calculate Reductions

Once emissions have been allocated to thermal and electrical generation, reductions for each (as applicable) can be calculated using the methods described under 'Estimating Reductions Associated with Energy Exports,' above.

## 2.5 Determining Registered Emission Reductions

For qualified reports, the quantity of registered emission reductions for any given Reporting Year is determined by summing the net changes in emissions, avoided emissions and sequestration for all subentities included in the entity's report to EIA. Using the formulas described in Section 2.4, above, any positive sum would be a net reduction, and any negative sum would be a net emissions increase. If the entity reported a net increase in emissions for a preceding year and that emission increase had not yet been fully offset by net emission reductions in subsequent years, the remaining quantity of emission increases (a negative number) would be summed with any net change for the current Reporting Year. The remainder, if positive, is the quantity of the entity's emission reductions eligible for registration.

Entities that wish to register emission reductions in any subsequent year must continue to submit qualifying reports for every year. These reports must include an annual assessment of their emission reductions and meet all of the other requirements for registering reductions, even if the assessment indicates that the entity did not achieve a net reduction of emissions.

The entity may also report offset reductions generated by non-reporting third parties. The quantity of offset emission reductions that is eligible for registration is determined independently for each third party, using the same procedure followed by each reporting entity and described above. For any given Reporting Year, this means that a reporting entity might not qualify for registered emission reductions, although it might still be receive recognition for registered reductions achieved by third parties covered by its report (or vice versa).

Summary data will be made available by EIA indicating, for each Reporting Year, the registered reductions attributed to each reporting entity and the third parties for whom it reported, including information on any net increases in emissions not yet offset by subsequent emission reductions. In addition, EIA will provide cumulative totals of the registered reductions and any net increases in emissions not yet offset by subsequent emission reductions.

## 2.6 Revising Previously Accepted Reports of Emission Reductions

Once a report on emission reductions has been accepted by EIA under the revised guidelines, it may be revised by the reporting entity only under certain conditions specified below and in the General Guidelines. Previously reported net changes in emissions, avoided emissions and sequestration for an entity or any of the third parties for which it is reporting may be made only to correct significant errors or omissions, including errors resulting from the estimation, rather than the measurement, of reporting year terrestrial carbon stocks. When using actual measurement of carbon stocks to correct prior year estimates, reporters may avoid revisions of multiple annual reports by assuming that all of the error occurred in the current reporting year. Such corrections may be submitted at any time and must be accompanied by a description of the corrections made, the significance of their effects on the net changes in emissions reported and an explanation of why they were needed. Previously submitted reports on emission reductions may not be modified to incorporate subsequent improvements in emission measurement or estimation techniques, nor may they be modified to incorporate reductions associated with acquisitions or divestitures that occurred after the affected reporting year.

# Glossary

[*Note to users*: The Glossary provides definitions for new terms used primarily in the draft Technical Guidelines, but also references terms defined in the General Guidelines, 10 CFR § 300.2.]

**Activity:** See General Guidelines, 10 CFR § 300.2

**Afforestation:** The establishment of forest or forest stands on lands that have not been recently forested.

**Aggregator:** See General Guidelines, 10 CFR § 300.2

**Agroforestry:** A land-use system that involves deliberate retention, introduction, or mixture of trees or other woody perennials in crop and animal production systems to take advantage of economic and/or ecological interactions among the components.

**Anaerobic lagoon:** A liquid-based organic waste management installation characterized by waste residing in water at a depth of at least 6 feet for periods of 30 to 200 days.

**Anaerobic decomposition:** Decomposition in the absence of oxygen, as in an anaerobic lagoon or digester, which produces $CO_2$ and $CH_4$.

**Avoided emissions:** See General Guidelines, 10 CFR § 300.2

**Base period:** See General Guidelines, 10 CFR § 300.2

**Base value:** See General Guidelines, 10 CFR § 300.2

**Biofuels:** Liquid fuels and blending components produced from biomass (plant) feedstocks, used primarily for transportation.

**Biogenic emissions:** See General Guidelines, 10 CFR § 300.2

**Biomass:** Non-fossilized organic matter available on a renewable basis, including organic material (both living and dead) from above and below ground, e.g., trees, crops, grasses, tree litter, roots, animals, and animal waste. Biomass includes forest and mill residues, agricultural crops and residues, wood and wood residues, animal wastes, livestock operation residues, aquatic plants, fast-growing trees and plants, and the organic portion of municipal and relevant industrial wastes.

**Calcining:** The process of thermally decomposing carbonate into quicklime, as in cement manufacturing.

**Carbon cycle:** The flow of carbon through the atmosphere, ocean, terrestrial biosphere, and lithosphere. Carbon exchange between carbon pools is driven by chemical, physical, geological, and biological processes. Also see **Carbon pool** below.

**Carbon dioxide equivalent ($CO_2e$):** The amount of carbon dioxide by weight emitted into the atmosphere that would produce the same estimated radiative forcing as a given weight of another radiatively active gas. Carbon dioxide equivalents are computed by multiplying the weight of the gas being measured (for example, methane) by its estimated global warming potential. The global warming potential (GWP) is the standard unit used for aggregating different greenhouse gases with dissimilar radiative forcing properties into a common unit. Also see Global warming potential below

**Carbon flow/carbon flux:** The movement of carbon from one carbon pool to another, expressed as a quantum transfer (flow), or as a rate per unit time (flux).

**Carbon pool:** Any reservoir of carbon. The four pools are atmosphere, biosphere, oceans and sediments.

**Carbon stocks:** See General Guidelines, 10 CFR § 300.2

**Chlorofluorocarbon (CFC):** Any of the various compounds of carbon, hydrogen, chlorine, and fluorine, typically used as refrigerants and for other purposes.

**Cogeneration facility:** A facility producing electricity and another form of useful energy (such as heat or steam) through sequential use of energy.

**Coke:** The solid black hydrocarbon left as a residual after the volatile hydrocarbons have been removed from bitumen by distillation. It is a fuel product often used in metal processing as a fuel and a reduction agent for oxide compounds, the use of which results in carbon dioxide emissions.

**Conversion factor:** A coefficient that converts units of one measurement system into corresponding units in another measurement system.

**Cropland:** A land cover/use category that includes areas used for the production of crops for harvest.

***De minimis* emissions:** See General Guidelines, 10 CFR § 300.2

**Deforestation:** The practice of managing forests to provide ecological, economic, social and cultural benefits for present and future generations. For the purposes of 1605(b) reporting, a determination of sustainably managed forests must be certified consistent with provisions of the Technical Guidelines, Chapter 1.I.3.5.

**Department** or **DOE:** See General Guidelines, 10 CFR § 300.2

**Direct emissions:** See General Guidelines, 10 CFR § 300.2

**Direct measurement:** Quantification of the greenhouse gas components of an exhaust stream by continuous emissions monitoring (CEM) or sufficient periodic sampling to closely approximate continuous monitoring.

**Direct monitoring:** See Direct measurement

**Double reporting**: When one entity submits emission or reduction data more than once or when two or more entities report the same emission or reduction.

**EIA** or **Energy Information Administration**: See General Guidelines, 10 CFR § 300.2

**Ecosystem carbon components:**

**Live tree –** A living woody perennial plant (capable of reaching at least 15 feet in height) with a diameter at breast height greater than 2.5 cm (1 inch), including the carbon mass in roots with diameters greater than 0.2 to 0.5 cm (note the specific diameter threshold will depend on sampling/estimation methods), stems, branches, and foliage.

**Tree seedling –** A trees less than 2.5 cm (1 inch) diameter at breast height.

**Standing dead tree –** A dead tree of at least 2.5 cm diameter at breast height that has not yet fallen, including the carbon mass of coarse roots, stems, and branches.

**Understory vegetation –** Roots, stems, branches, and foliage of tree seedlings, shrubs, herbs, forbs, and grasses.

**Forest floor –** Fine woody debris (smaller than 7.5 cm), tree litter, humus, and fine roots in the organic forest floor layer above mineral soil.

**Down dead wood –** Logging residue and other coarse dead wood on the ground (greater than 7.5 cm diameter), as well as stumps and the coarse roots of stumps.

**Soil –** Includes fine roots and all other organic carbon not included in the above pools, to a depth of one (1) meter.

**Harvested wood** – Wood removed from the forest ecosystem for the processing of various products. Logging debris (slash) left in the forest after harvesting is not included.

**Emissions:** See General Guidelines, 10 CFR § 300.2

**Emissions coefficient:** A unique value for scaling emissions to activity data in terms of a standard rate of emissions per unit of activity (e.g., pounds of carbon dioxide emitted per Btu of fossil fuel consumed).

**Emissions factor:** see Emissions coefficient

**Emissions, fugitive:** Any unintentional release of greenhouse gases to the atmosphere, including methane from the processing, transmission, and/or transportation of fossil fuels, HFCs from stationary and mobile air-conditioning and refrigeration equipment, $SF_6$ from electric power distribution, and methane from solid waste landfills.

**Emissions intensity**: See General Guidelines, 10 CFR § 300.2

**Emissions, process:** Emissions inherent in a productive process, as in cement or ammonia manufacture, as distinguished from those resulting from fuel combustion.

**Emissions source:** A discrete process, occurring at a particular location, which emits one or more Greenhouse Gases.

**Engineered sequestration:** An engineered process whereby carbon dioxide is captured from the point of emission and then stored in underground reservoirs (geologic sequestration), dissolved in deep oceans, or converted to rock-like solid materials.

**Enteric fermentation:** Animal digestion aided by methane-generating microbes in the animal rumen and intestine that produces greenhouse gas emissions, primarily methane.

**Entity** or **reporting entity:** See General Guidelines, 10 CFR § 300.2

**Entity boundary:** The limit in the scope of coverage for an entity's emission inventory and emission reduction report.

**Entity statement:** The 1605(b) participant's description of entity name, primary activities, covered sites and activities, emissions measurement method(s) and the applicability of each method to separate operations. In the case of entities seeking to register emission reductions, the entity statement also provides information on the methods used to define the operational boundaries of the entity and the resulting entity boundaries, shared ownership arrangements, designation of a start year, description of baseline methods, and identification of sub-entities to which different measurement methods may apply.

**Equity share:** The percentage interest in ownership, benefits, or control that may govern entitlements to emission reductions by participants in collective undertakings.

**Estimation method:** The technique, including key assumptions and data sources, used by a 1605(b) participant to derive reported emissions, emission reductions, and/or sequestration where actual measurement is not possible or practical.

**Financial control:** The ability to direct the financial and operating policies of an operation with a view to gaining economic benefits from its activities.

**First reduction year:** See General Guidelines, 10 CFR § 300.2

**Flaring**: The combustion of non-utilized gases prior to release into the atmosphere. See also Venting

**Forest land**: Land at least 10 percent stocked by forest trees of any size, or formerly having such tree cover, and not currently developed for non-forest uses. The minimum area considered for classification is one (1) acre.

**Forest management**: The practical application of biological, physical, quantitative, managerial, economic, social, and policy principles to the regeneration, tending, protection, harvest, access, utilization, and conservation of forests to meet specified goals and objectives while maintaining the productivity of the forest.

**Fugitive emissions:** See General Guidelines, 10 CFR § 300.2

**General Guidelines**: The emission and emission reduction Guidelines that appear in Part 300 of the U.S. Code of Federal Regulations.

**Geologic sequestration:** A type of engineered sequestration, where captured carbon dioxide is injected for permanent storage into underground geologic reservoirs, such as oil and natural gas fields, saline aquifers, or abandoned coal mines.

**Global warming potential (GWP):** An index used to compare the relative radiative forcing of different gases without directly calculating the changes in atmospheric concentrations. GWPs are calculated as the ratio of the radiative forcing that would result from the emission of one kilogram of a greenhouse gas to that from the emission of one kilogram of carbon dioxide over a fixed period of time, such as 100 years.

**Grassland:** Rangelands and pasturelands that are not considered cropland and would not become forestland without human intervention.

**Greenhouse gases (GHGs):** See General Guidelines, 10 CFR § 300.2

**Heating value:** The amount of thermal energy released per unit of a fuel that is burned completely.

**Hydrofluorocarbons (HFCs):** A class of anthropogenically created chemical compounds composed of one or more carbon atoms and varying numbers of hydrogen and fluorine atoms. Most HFCs have potent radiative forcing effects, with 100-year GWPs generally between 1,300 and 12,000 times that of carbon dioxide.

**Independent verifier:** One who is qualified to attest to the accuracy and completeness of emissions reports and who is capable of independent assessment by virtue of having no ties to the emitter that might create a conflict of interest.

**Independent verification:** See Verification

**Indirect emissions:** See General Guidelines, 10 CFR § 300.2

**Intergovernmental Panel on Climate Change (IPCC):** A panel established jointly by the World Meteorological Organization and the United Nations Environmental Program in 1988 to assess scientific, technical and socio-economic information relevant to climate change, its potential impacts, and options for adaptation and mitigation.

**Inventory:** A quantified account of an entity's total Greenhouse Gas emissions.

**Landfill gas:** Gas that is generated by the decomposition of organic material at landfill disposal sites. The average composition of landfill gas is approximately 50 percent methane and 50 percent carbon dioxide and water vapor by volume. The methane percentage, however, can vary from 40 to 60 percent, depending on several factors including waste composition (e.g. carbohydrate and cellulose content). The methane in landfill gas may be vented, flared, combusted to generate electricity or useful thermal energy on-site, or injected into a pipeline for combustion off-site.

**Large emitters:** For the purpose of 1605(b) reporting, entities that emit more than 10,000 tons of carbon dioxide equivalent in a single year or averaged over a multi-year period, determined at the time that the entity first reports.

**Life cycle:** The progression of a product or facility through its service life.

**Look-up tables:** Reference tables, typically provided to relate values of an observable parameter to corresponding values of less easily observed variables.

**Managed carbon stocks**: Stocks that are affected by human decision or action. Examples include managed forest, engineered carbon sinks, or certain agricultural practices.

**Mass balance:** A method for calculating emissions based on the mass and composition of fuel inputs, appropriate emissions factors, and combustion performance.

**Materials balance calculation:** A computation of carbon flow through an industrial process.

**Mineral soils:** A soil consisting predominantly of, and having its properties determined predominantly by, mineral matter. Usually contains less than 200 g/kg organic carbon (less than 120-180 g/kg if saturated with water), but may contain an organic surface layer up to 30 cm thick.

**Mobile source emissions:** Transportation emissions, plus emissions from small engines such as lawnmowers and equipment used at commercial and industrial sites, non-road equipment used in farming and forestry, at airports, and at railroad and marine terminals.

**Municipal solid waste:** Residential solid waste and some non-hazardous commercial, institutional, and industrial wastes.

**Natural disturbances:** Processes or events such as insect outbreaks, fire, disease, flooding, windstorms and avalanches that cause ecosystem change.

**Net carbon flow:** The sum of all transfers of carbon between the land and the atmosphere over a specified period. See also Carbon flow/carbon flux

**Net emission reductions** or **net entity-wide emission reductions:** See General Guidelines, 10 CFR § 300.2

**Offset:** See General Guidelines, 10 CFR § 300.2

**Operational control:** The authority to introduce and implement operating policies in an organization.

**Operations data system:** A data collection system that reports the physical quantities of inputs utilized and products manufactured. These data are typically produced for management and regulatory compliance needs and are usually held at the facility level in the organization.

**Organic growth/decline:** Increases/decreases in greenhouse gas emissions as a result of changes in production levels, net investment in new capacity, and changes in product mix, as distinguished from acquisitions and divestitures.

**Organic soils:** Soil materials that are saturated with water and have 174g/kg or more organic carbon if the mineral fraction has 500 g/kg or more clay, or 116 g/kg organic carbon if the mineral fraction has no clay, or has proportional intermediate contents. If these materials were never saturated with water they would have 203 g/kg or more organic carbon.

**Organizational boundary**: The scope of the entity covered by 1605(b) reporting, as defined in the entity statement. Generally, the organizational boundary of an entity encompasses all facilities and operations that are under the management control of the entity, which usually includes all land, facilities and vehicles that are wholly or majority owned or under long-term lease by the entity, as well as certain other facilities, vehicles or land that are under the management control of the entity. See also Entity Boundary

**Outsourcing: C**ontracting out activities by an entity to other businesses, where the output of the outsourced activity is later re-integrated into the entity's products or is otherwise integral to the entity's operations.

**Permanence: T**he longevity of carbon in a carbon sink (such as forest land).

**Perfluorocarbons (PFCs):** A group of man-made chemicals composed of one or six carbon atoms and four to fourteen fluorine atoms, containing no chlorine. PFCs are compounds derived from hydrocarbons by replacement of hydrogen atoms by fluorine atoms. PFCs have several commercial uses and are emitted as a byproduct of aluminum smelting and semiconductor manufacturing. PFCs have very high 100-year Global Warming Potentials and are very long-lived in the atmosphere.

**Prescribed fire:** Intentionally set and managed forest burns, which further specific resource management objectives.

**Process emissions:** See Emissions, process

**Process models:** Mathematical representations of ecosystem processes, such as nitrogen and carbon cycles.

**Reforestation:** The re-establishment of forest cover, naturally or artificially, on lands that have recently been harvested or otherwise cleared of trees.

**Regeneration:** The natural (by natural seeding, coppice, or root suckers) or artificial (by direct seeding or planting) process of re-establishing tree cover on forestland.

**Registration:** The recognition offered for emission reductions submitted under the 1605(b) reporting Guidelines, supported by a conforming inventory and accepted by DOE. An entity may

have entity-wide emissions and emission reductions registered by conforming to the requirements of §§ 300.1, 300.6, and 300.7.

**Reporting:** If an entity does not choose to report emissions in a manner that conforms to the registration requirements, including those set forth in §§ 300.6 and 300.7 of these Guidelines, then the entity may choose to report on any emissions or any emission reductions by complying with the other requirements of Part 300 of these Guidelines.

**Reporting Year:** See General Guidelines, 10 CFR § 300.2

**Sequestration:** See General Guidelines, 10 CFR § 300.2

**Simplified Inventory Estimation Tool (SIET):** See General Guidelines, 10 CFR § 300.2

**Silviculture:** The art and science of controlling the establishment, growth, composition, health, and quality of forests and woodlands.

**Sink:** See General Guidelines, 10 CFR § 300.2

**Small emitters:** For the purposes of 1605(b) reporting, entities whose operations emit 10,000 tons or less of carbon dioxide equivalent annually, determined at the time that the entity first reports and periodically thereafter.

**Source:** See General Guidelines, 10 CFR § 300.2

**Start year**: See General Guidelines, 10 CFR § 300.2

**Stationary sources**: Emission sources at fixed locations, such as power plants, factories, refineries, mines, heating plants or waste conversion facilities.

**Subentity:** See General Guidelines, 10 CFR § 300.2

**Sustainable Forest Management:** Forest and forest lands stewardship and use that integrates the reforestation, management, growing, nurturing, harvesting, and utilization of the trees for useful products with the conservation of soil, air, and water quality, wildlife and fish habitat, and aesthetics to meet present and future needs.

**Technical Guidelines:** Detailed explanatory supplements to the 1605(b) General Guidelines.

**Terrestrial sequestration:** Biotic sequestration of carbon in above- and below-ground biomass and soils.

**Total emissions**: See General Guidelines, 10 CFR § 300.2

**Total entity-wide emission reductions**: The sum of all annual changes in emissions, carbon stocks and avoided emissions of the greenhouse gases specifically identified in Section 300.6(f), determined in conformance with §§ 300.7 and 300.8 of these Guidelines. In calculating this total, decreases in emissions and increases in carbon stocks and avoided emissions are expressed as positive values.

**Transportation sources:** In the context of emissions, transportation sources include vehicles that operate on roads and highways, as well as non-road vehicles, engines, and equipment, but exclude farm equipment associated with particular farm premises. Examples of transportation sources include cars, trucks, buses, earth-moving equipment, lawn and garden power tools, ships, railroad locomotives, and airplanes.

**United States or U.S.:** See General Guidelines, 10 CFR § 300.2

**Venting:** Release of gases into the atmosphere without combustion. See also Flaring

**Verification:** A process by which an organizationally independent source assess the accuracy, completeness and conformity with DOE Guidelines of proffered entity reports of emissions and emission reductions, in accord with 1605(b) Guidelines.

**Wood products**: Products derived from the harvested wood from a forest, including fuel-wood and logs and the products derived from them such as cut timber, plywood, wood pulp, paper, etc. Includes both products in use and in disposal systems such as landfills (but which have not yet decayed, releasing carbon to the atmosphere as carbon dioxide and/or $CH_4$).