

Calculation Tools for Estimating Greenhouse Gas Emissions from Wood Product Facilities

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CALCULATION TOOLS FOR ESTIMATING GREENHOUSE GAS EMISSIONS FROM WOOD PRODUCTS MANUFACTURING FACILITIES

EXECUTIVE SUMMARY

This report presents the results of a review of existing greenhouse gas (GHG) inventory protocols and calculation tools designed to assist companies in preparing GHG inventories. It is intended that these industry-specific tools be used in conjunction with a GHG accounting protocol, such as the “Greenhouse Gas Protocol” issued by the World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD), the “Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance” issued by the United States EPA (USEPA), the “Challenge Registry Guide to Entity and Facility-Based Reporting” issued by the Voluntary Challenge and Registry (VCR), or other protocol for corporate GHG inventories.

These tools reflect many of the features of well-known and widely accepted protocols. In addition, they anticipate a number of questions that wood products plants must address when preparing facility-level or company-level inventories. A special effort has been made to ensure that the tools are consistent with guidance issued by the Intergovernmental Panel on Climate Change (IPCC) and the WRI/WBCSD.

These tools estimate CO₂ emissions from fossil fuel combustion based on the carbon content of the fuel (or a comparable emission factor) and the amount burned. Carbon dioxide emissions from biomass combustion are not counted as GHG emissions, a convention common to most of the protocols examined in this review, but if a company elects to it can report them separately. Companies that wish to comply with the WRI/WBCSD GHG Protocol should include these biomass combustion CO₂ emissions, and they should be reported separately from direct GHG emissions. Regardless of the reporting approach chosen, it is important to clearly separate estimates of CO₂ emissions from fossil fuel combustion from those of CO₂ emissions from biomass combustion. Methods for estimating CO₂ emissions originating from resins contained in wood residual fuels are also provided. Methane and nitrous oxide emissions from combustion processes, both fossil fuel and biomass, are estimated using fuel-based emission factors and activity data. Greenhouse gas emissions from landfills and wastewater treatment plants are estimated using methods derived from those suggested by IPCC, as are emissions from vehicles and other fossil fuel-fired equipment. In all cases, however, companies may use site-specific information where it yields more accurate estimates of GHG emissions than the tools outlined in this report. Annex H contains tables populated with the recommended GHG emission factors discussed throughout the body of the report.

Using these tools, indirect emissions related to imports of electricity or steam are included in the inventory results but are tracked separately from direct emissions. Emissions attributable to exports of electricity or steam, which are a subset of direct emissions, are explicitly delineated in order to demonstrate that at some facilities a portion of the direct emissions are associated with energy streams that are exported to other end users. Emissions from combined heat and power (CHP) plants are allocated using the WRI/WBCSD “efficiency method.”

The calculation tools allow companies to develop their corporate inventories, including all direct emission sources from within their organizational boundaries (e.g., company-owned truck fleets) as well as indirect emission sources outside of the organizational boundaries (e.g., emissions from electricity, heat, and steam purchased and consumed), and on-site manufacturing operations outside the organizational boundary. It is understood, however, that companies will include the indirect emissions sources that are best suited to the objectives of the inventory. For most plants, the GHG profile will be dominated by stationary fossil fuel combustion emissions and emissions attributable to purchases of power and steam, emissions that are discussed in Sections 8 and 10.

Annexes I and J contain a series of example calculations, both in SI and in “English” units, designed to illustrate the recommended methods for estimating emissions as discussed in the report. For inventories which consider CO₂ emissions only (i.e., CH₄ and N₂O emissions are not included in the emissions inventory), it may be appropriate to estimate emissions based solely on facility-level fuel consumption activity data and CO₂ emission factors. In certain situations, CH₄ and N₂O emissions may be estimated adequately using facility-level activity data as well.

To aid in interpreting the results of the inventory, these tools recommend that the results include a description of the operational boundaries of the inventory and a list of emission factors used to estimate emissions. The format suggested for presenting the results of the inventory allows a company to separate direct emissions (those from sources owned or controlled by the company) from indirect emissions (those that are a consequence of the activities of the company, but occur from sources owned or controlled by another company). The company is free to select a method for determining the ownership of emissions, but the method should be explained in the inventory results. The user is directed to the WRI/WBCSD GHG Protocol for guidance on how to determine ownership of emissions from partly-owned or partly-controlled sources.

An Excel[®] workbook is available to assist in performing the calculations described in this report.

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CALCULATION TOOLS FOR ESTIMATING GREENHOUSE GAS EMISSIONS FROM WOOD PRODUCTS MANUFACTURING FACILITIES

1.0 INTRODUCTION

Responding to the need for improved methods for estimating greenhouse gas (GHG) emissions from wood products manufacturing facilities, in 2002 the American Forest and Paper Association (AF&PA) and the Forest Products Association of Canada (FPAC) requested that the National Council for Air and Stream Improvement, Inc. (NCASI) review existing GHG protocols and assist the industry in developing calculation tools for estimating GHG emissions. The goals of this activity are to:

- enable harmonized collection of credible, transparent, and comparable data
- address the forest products industry's unique attributes
- establish a framework that will assist in implementing a variety of programs that might make use of carbon inventory data

The results of that effort are contained in this report. The calculation tools are described in the body of the report. The Annexes summarize relevant features of the calculation methods used in a number of existing GHG protocols and provide additional details on estimation methods. The Annexes contain many of the country-specific data and factors published by national authorities. The information in the Annexes was current as of the end of 2001.¹

This material encompasses only manufacturing-related emissions from wood products production. Issues related to carbon sinks or forest sequestration are not addressed.²

These calculation tools will assist companies in preparing GHG emission inventories for a number of purposes, including internal company benchmarking, public reporting, product profiles, and carbon trading. The rules governing the development of a GHG inventory, however, can vary substantially from one program to another, so the user of these tools should always be familiar with the requirements imposed by the intended use of the inventory results.

These industry-specific tools should be used in conjunction with an accepted GHG accounting protocol such as the “Greenhouse Gas Protocol” issued by the World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD), the “Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance” issued by the United States EPA (USEPA), the “Challenge Registry Guide to Entity and Facility-Based Reporting” issued by the Voluntary Challenge and Registry (VCR), or other protocols for corporate GHG inventories. Those protocols provide valuable information on issues ranging from defining the objectives for a GHG inventory to options for verifying the results—issues beyond the scope of the industry-specific calculation tools in this report. Georgia-Pacific

¹ Some of the information in the annexes has been updated to reflect changes incorporated to the March 2004 GHG Protocol Revised Edition (WRI 2004). Where updates have been made they are noted in footnotes.

² IPCC has developed methods that countries are using to characterize sequestration (IPCC 1997a, b, c, 2000b), and a great deal of work is underway to improve the understanding of sequestration and its measurement. Some of these studies are summarized by Skog and Nicholson 1998; Apps et al. 1999; Matthews 1996; and Birdsey 1996.

Corporation's protocol is an example of how one company developed a protocol specific to the forest products industry (GP 2002).

2.0 FOREST PRODUCTS INDUSTRY GREENHOUSE GAS EMISSIONS IN PERSPECTIVE

The forest products industry has an important and complex role in the global carbon cycle. Forests supply the industry's primary raw material. The sustainable management of these forests sequesters massive amounts of carbon and provides needed products that contribute to significant carbon pools during their use and after being discarded. In addition, forests provide multiple environmental, societal, and economic benefits.

Efforts to expand the amount of forested land are increasing carbon storage in most of the developed world and new plantations are being established in many areas of the developing world. Research is ongoing to identify forest management practices capable of optimizing carbon storage in existing forests while maintaining or enhancing forest productivity and protecting the environment.

Carbon is also stored when forests are managed to produce needed products because many of these products store carbon for extended periods of time as they are used and after disposal. Recycling is an important part of the carbon cycle because it can help extend the time during which carbon is stored in products. It has been estimated that the amount of carbon stored in forest products is increasing by 139 million metric tons of carbon per year on a global basis (Winjum, Brown, and Schlamadinger 1998).

The forest products industry relies heavily on biomass fuels that displace fossil fuels, the primary contributor to rising atmospheric levels of carbon dioxide. In a number of countries, more than half the industry's energy requirements are met using biomass fuels. Forest products that are not recycled can provide a source of biomass fuels.

The forest products industry is one of the global leaders in the use of combined heat and power (CHP) systems, also called cogeneration systems. CHP systems produce electrical power and thermal energy from the same fuel, yielding twice as much or more usable energy from the fuel as normal methods for generating power and steam. This reduces GHG emissions by reducing the demand for fossil fuels.

The industry's interactions with the global carbon cycle are extensive and complex. It is important, therefore, that the industry's GHG emissions not be viewed in isolation. It is only within the context of the overall forest products carbon cycle that the significance of the industry's emissions can be properly evaluated.

3.0 RELATIONSHIP OF THESE CALCULATION TOOLS TO OTHER GREENHOUSE GAS PROTOCOLS

There are many protocols for estimating and reporting GHG emissions. Most of the existing protocols are based on a common set of general principles with differences primarily attributable to the differing purposes of the protocols (e.g., national inventories, corporate inventories, etc.). The general principles for GHG inventory development are important and

should be addressed in preparing any inventory of GHG emissions. This report, however, devotes relatively little attention to such issues because the principles are generic and information is available in a variety of other places.

Some especially helpful sources of general information on inventory preparation are:

- the Intergovernmental Panel on Climate Change (IPCC) (IPCC 1997a, b, c, 2000a)
- the World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD) (WRI 2001a, 2004)
- the PEW Center on Global Climate Change (Loreti, Wescott, and Isenberg 2000; Loreti, Foster, and Obbagg 2001)
- the United States Environmental Protection Agency (USEPA 2003)
- Canada's Climate Change Voluntary Challenge and Registry (VCR 2003)

The WRI/WBCSD and PEW Center documents are especially relevant for companies using these calculation tools because they focus on company-level reporting. Instructions on how to obtain these documents are included in the literature citations. The WRI/WBCSD and PEW Center documents provide helpful information on these generic, but important, issues:

- GHG accounting and reporting principles (e.g., relevance, completeness, consistency, transparency, accuracy)
- defining corporate objectives for inventories (e.g., public reporting, voluntary initiatives, carbon trading)
- establishing organizational and operational boundaries
- establishing historical reference data and tracking emissions over time
- managing inventory quality
- verification

The wood products industry calculation tools in this report are intended to assist companies in developing data that can be used to fulfill the requirements of a number of protocols, including the WRI/WBCSD GHG Protocol. Figure 1 graphically illustrates some of the potential uses of the calculation tools in the context of an example corporate GHG inventory.

Given the widespread acceptance of the WRI/WBCSD GHG Protocol, it is important to note that there is one area where these calculation tools may yield information that is not completely sufficient for reporting under the WRI/WBCSD GHG Protocol. Specifically, the GHG Protocol suggests that companies report emissions of hydrofluorocarbons (HFCs) from air conditioning and refrigeration, but HFC emissions are not addressed in these wood products plant calculation tools. WRI/WBCSD has a calculation tool for estimating HFC and PFC emissions (*Tool for Calculating HFC and PFC Emissions from the Manufacturing, Installation, Operation and Disposal of Refrigeration and Air-conditioning Equipment, Version 1.0*), available for download from the GHG Protocol website (www.ghgprotocol.org). The IPCC has also issued guidance that companies wanting to estimate these emissions might find helpful (IPCC 1997c, Section 2.17.4.2).

There are other differences between the WRI/WBCSD GHG Protocol and the calculation tools presented here, but the differences result in these tools providing additional information not required by the GHG Protocol or providing it in a slightly different format.

Perhaps the only significant variance from IPCC's recommended approaches is in the area of landfill emissions. IPCC's approach relies on generic estimation methods, while these tools suggest that site-specific landfill gas collection data can often be used as the basis for the estimates where these data are available.

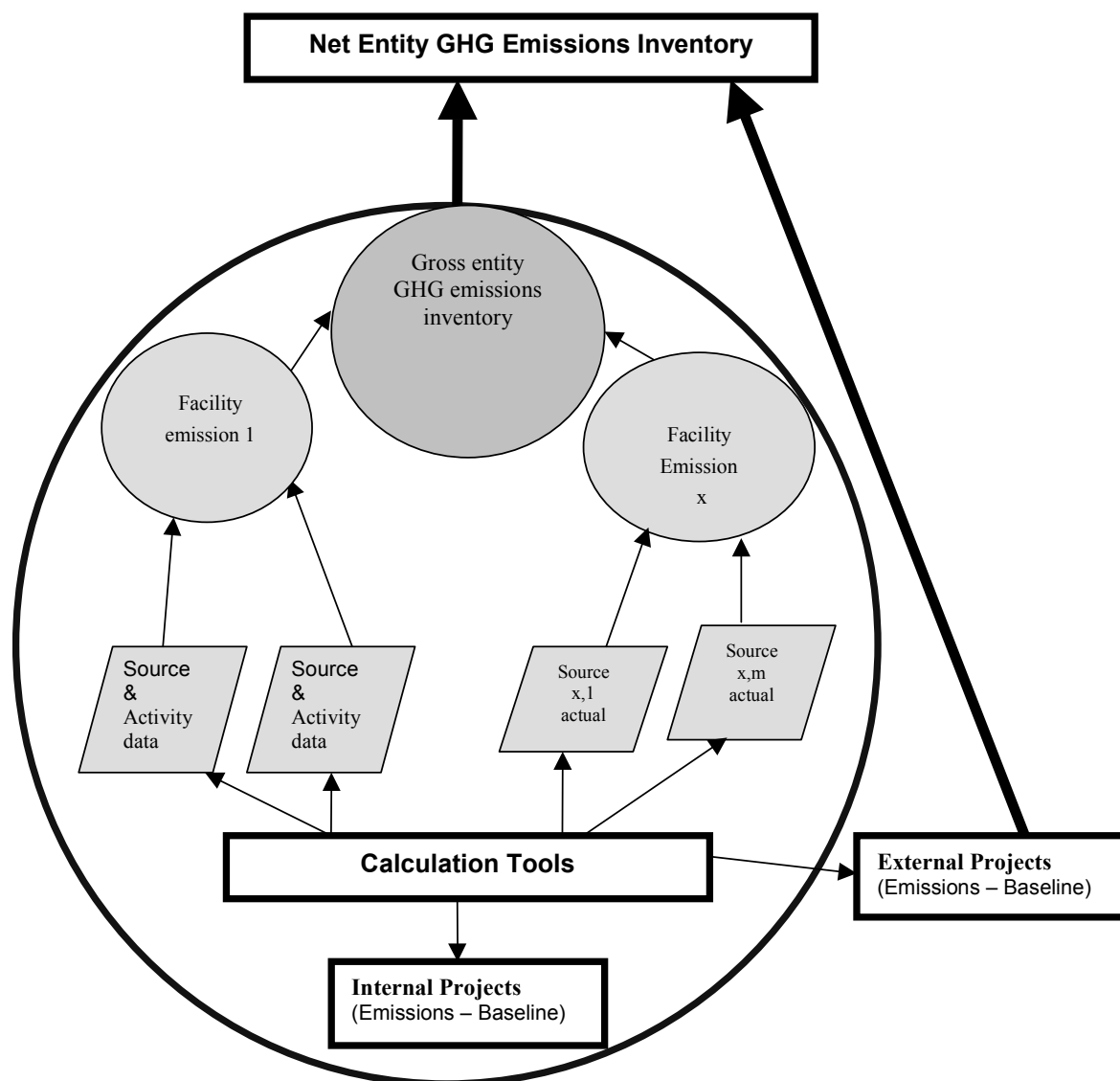


Figure 1. Some of the Possible Uses of the Calculation Tools in the Context of an Example Corporate GHG Inventory

4.0 OVERVIEW OF THE CALCULATION TOOLS

4.1 Steps Involved in Applying the Calculation Tools

In general terms, the calculation tools involve the user performing the following steps, most of which are described in detail in later sections of this report.

4.1.1 *Determining the Objectives of the Inventory*

Most protocols for developing corporate GHG inventories, including the WRI/WBCSD GHG Protocol, can help companies understand the variety of uses for GHG inventory results (WRI 2001a, 2004). The way the inventory is designed and conducted will depend largely on the intended uses of the results. Before undertaking a GHG inventory, therefore, companies should assure themselves that the methods used to develop the inventory meet the requirements imposed by its objectives.

4.1.2 *Identifying Boundary Conditions*

There are two types of boundaries that must be considered in a GHG inventory—operational and organizational. Organizational boundaries reflect ownership or control of the company’s operations and legal structure. The GHG Protocol (WRI 2004) provides extensive guidance regarding determination of organizational boundaries. It describes the process of setting organizational boundaries as “select[ing] an approach for consolidating GHG emissions and then consistently apply[ing] the selected approach to define those businesses and operations that constitute the company for the purpose of accounting and reporting GHG emissions.” The GHG Protocol recommends that either of two approaches be used to consolidate GHG emissions in setting organizational boundaries: the equity share and the control approaches. An extensive discussion of determining organizational boundaries, including examples, is provided in the GHG Protocol (WRI 2004).

The operational boundaries define the emission sources that need to be included in order to satisfy the objectives of the inventory, categorize them into “direct” and “indirect” emissions, and determine the scope of accounting and reporting for indirect emissions. Direct and indirect emissions are defined as follows (WRI 2001a, 2004):

- **Direct emissions** are “emissions from sources that are owned or controlled by the [reporting] company.”
- **Indirect emissions** are “emissions that are a consequence of the activities of the [reporting] company but occur at sources owned or controlled by another company.”

Of course, there is an almost endless chain of upstream and downstream “consequences” that, at least theoretically, can be connected to a company’s activities. GHG protocols, however, usually require only a limited set of indirect emissions—those associated with transfers of electrical power, steam, and heat consumed by the company but produced by another entity—and these are the indirect emissions addressed in these calculation tools.

The tools have been developed to address:

- direct emissions from on-site operations (e.g., company-owned power boilers)
- direct emissions from off-site operations (e.g., company-owned harvesting equipment)
- the portion of direct emissions attributable to exported power or steam
- indirect emissions related to imports of power or steam (including those from outsourced power islands)
- indirect emissions from on-site operations not involving power and steam transfers (e.g., outsourced but on-site wastewater treatment operations)

Companies preparing reports meeting the requirements of the GHG Protocol need to include all direct emissions as well as those indirect emissions attributable to imported electricity, steam, and heated or cooled water (WRI 2004).

Emissions from operations that are not part of the normal wood products manufacturing process are not included within the scope of these tools, although companies may sometimes need to include them to satisfy the objectives of the inventory (e.g., if they are within the organizational boundaries of the company). Tools for many of these other types of operations are available on the GHG Protocol website (WRI 2004).

4.1.3 Estimating Emissions

The next step is estimating the GHG emissions. The calculation tools in this report address:

- CO₂ emissions from stationary fossil fuel combustion
- CH₄ and N₂O emissions from fossil fuel-fired units and biomass-fired boilers and wood and panel dryers
- CO₂, CH₄, and N₂O emissions from transportation and mobile sources (including company-owned harvesting equipment and company-owned truck fleets)
- CH₄ emissions attributable to plant wastes in landfills and anaerobic waste treatment operations
- GHG emissions associated with power and steam that is imported and consumed
- GHG emissions attributable to power and steam exports

These tools for estimating GHG emissions from wood products manufacturing facilities allow companies to estimate CO₂ releases derived from biomass, but this carbon is not included in GHG emission totals (i.e., it is tracked separately) because it is considered “carbon neutral.” Biomass carbon is considered “carbon neutral” because the carbon in biomass originates in the atmosphere. The burning of biomass recycles carbon to the atmosphere, unlike the burning of fossil fuels, which adds new carbon to the atmosphere. The GHG Protocol follows a reporting convention consistent with that used in national inventories, where CO₂ emissions from the combustion of biomass are included for informational purposes but are not included in national emissions totals. Emissions of biomass-derived CO₂ are addressed in Annex G.

Although not addressed in these calculation tools, fuel gas system piping (e.g., piping associated with a natural gas boiler) may have methane equipment leaks. Where users wish to address such fugitive emissions, which would probably be small in relation to the GHG emissions categories listed above, more information can be obtained in the USEPA publication *Protocol for Equipment Leak Emission Estimates* (USEPA 1995).

4.1.4 Presenting Results

The calculation tools emphasize the disaggregated and transparent presentation of results. Section 14 includes an example format for reporting inventory results, which provides the company an opportunity to convey transparent and disaggregated information (however, the reporting company may choose to report using a different format). An example format for providing additional information on emissions of biomass-derived CO₂ is shown in Annex G.

4.2 Data Quality

The calculation tools described in this report can be used to develop estimates for a number of purposes. To a large extent, the purpose of the inventory will dictate the quality of the data that are needed and the approach used to develop the inventory. In developing corporate benchmarking data, for instance, it might be acceptable to use a generic emission factor for coal burning, but a carbon trading program might require that emission estimates be based on the carbon content of the specific coal being burned. The data quality requirements imposed by the intended use of the inventory should be defined before the company begins the inventory.

For most purposes, it is acceptable for companies to estimate GHG emissions using emission factors and corresponding “activity data” (e.g., amount of fuel consumed or miles traveled). For most plants, the largest sources of GHG emissions are fossil fuel-fired stationary combustion units. Fortunately, in most cases these emissions can be accurately estimated. Because facilities must pay for fossil fuels, companies usually have excellent records of the types and amounts of fossil fuel being purchased and consumed. CO₂ emissions from these sources are directly related to fuel carbon content as reflected in widely accepted emission factors.

For most other sources, however, the quality of GHG emission estimates is much lower, sometimes because of inadequate activity data, but more often due to emission factors that are based on very few data. Because of the importance of emission factors to the results of a GHG inventory, these calculation tools include a table (Table 14) that companies are encouraged to use to show the emission factors used to develop the inventory.

It can be expected that many more emission measurements will be made in coming years and improved emission factors will be developed reflecting these new data. Users of emissions inventory data need to understand this process and the resulting impact it will have on GHG inventory results. One can be certain that the quality of the estimates will improve over time, but it is impossible to forecast whether the estimates will be adjusted upward or downward in the process. The changes are expected to be relatively unimportant to the GHG profile of most plants, however, because the largest sources of GHGs from most wood products plants, stationary fossil fuel combustion units, are well understood.

4.3 Units

Different countries use different units of measure (e.g., short tons versus metric tonnes, US gallons versus UK gallons). This can create considerable confusion when emission factors and estimation techniques are applied internationally. In this report both the SI (metric) system and the “English” system of units are used. Tables of emission factors are provided in both unit sets, as are the example calculations provided in Annexes I and J. Information contained in the other Annexes contains emission factors and other parameters in the units preferred by the authority or country responsible for the information. Annex K presents factors that can be used to convert between differing units of measure. Some of the important issues related to units of measurement are highlighted here.

4.3.1 Units of Measure for Greenhouse Gases

Greenhouse gases are often compared on the basis of their estimated potential to cause global warming. Factors called Global Warming Potentials (GWPs) have been developed which can be used to convert a quantity of non-CO₂ greenhouse gas into an amount of CO₂ with an equivalent warming potential. Although the derivation of these factors involves a large number of assumptions, GWPs are almost universally used to compare one greenhouse gas to another. The GWP for CH₄ is 21 so, from the standpoint of potential global warming, every gram of CH₄ is equivalent to 21 grams of CO₂. The GWP for N₂O is 310.³ The derivation of these factors is explained elsewhere (IPCC 1996). When an emission estimate is the sum of several GHGs expressed as the equivalent amount of CO₂, the estimate is said to be in CO₂-equivalents, sometimes abbreviated as CO₂e, CO₂eq, or CO₂-equiv. To convert CO₂, CH₄, and N₂O emissions into CO₂-equivalents, multiply CH₄ emissions by 21 and N₂O emissions by 310, then add both to CO₂ emissions.

CO₂-equivalents are also sometimes reported as the weight of the carbon in the CO₂-equivalents, usually reported in metric tons of carbon equivalents (MTCEs). MTCEs are calculated by multiplying the weight (in tonnes, equal to 1000 kg) of CO₂-equivalents by 12/44, the weight fraction of carbon in carbon dioxide.

For purposes of transparency and to avoid confusion, in these calculation tools greenhouse gas quantities are usually reported in terms of the mass of the individual GHG rather than in CO₂-equivalents or MTCEs. In some cases, however, companies may find that it is appropriate to use emission factors that are based on the combined emissions of several GHGs expressed in terms of CO₂-equivalents or MTCEs. This is acceptable provided it is made clear in the results.

4.3.2 Heat Content of Fuels – HHV vs. LHV

Some countries measure fuel according to its higher heating value (HHV) or gross calorific value (GCV), while other countries use lower heating value (LHV) or net calorific value (NCV). The distinction between HHV and LHV arises from the different physical states (liquid or gaseous) water may be in following combustion. The HHV includes the latent energy of condensation of water following combustion. The LHV is computed for product water in the gaseous state (i.e., not condensed). The latent energy of vaporization of water is deducted from the HHV. When a moist fuel is combusted, two sources of product water exist—the moisture present in the fuel and the water formed from the hydrogen in the fuel during combustion.

The LHV of a fuel at any moisture content can be determined as (Kitana and Hall 1989, p. 883):

³ Recent research summarized in IPCC 2001 suggests that the GWP for CH₄ should be higher (23) and that for N₂O should be lower (296) than the values previously recommended by IPCC (1996). However, the revised GWPs have not been widely adopted at this time. Therefore, this report uses the GWP values recommended by IPCC (1996) (21 for CH₄ and 310 for N₂O).

$$LHV = (1 - M_{wet})[HHV_{solids} - \lambda(M_{dry} + 9H)] \quad (Eq. 1)$$

where: LHV = net calorific value at any moisture content
 HHV_{solids} = gross calorific value of dry fuel (zero moisture content)
 λ = latent heat of vaporization of water (2.31 MJ/kg at 25 °C)
 M_{wet} = moisture content of fuel on a wet basis (expressed as a fraction)
 M_{dry} = moisture content of fuel on a dry basis (expressed as a fraction)
 H = mass fraction of hydrogen in dry fuel (expressed as a fraction)

If the LHV is to be expressed in terms of dry fuel (e.g., corresponding to the dry solids in the fuel) it can be determined from the HHV of the dry fuel (HHV_{solids}):

$$LHV_{solids} = HHV_{solids} - 9\lambda H \quad (Eq. 2)$$

where: LHV_{solids} = net calorific value of dry fuel (zero moisture content)

A commonly accepted approximation is that LHV is 95% of HHV for coal and oil and 90% of HHV for natural gas (IPCC 1997c). IPCC does not provide a relationship between LHV and HHV for biomass fuels, presumably because the moisture content of biomass fuels can vary extensively. However, in most instances the forest products industry characterizes the energy content of biomass fuels (e.g., spent pulping liquors, hogged fuels, etc.) in terms of the energy in the dry solids of the biomass. Therefore, Equation 2 can be used to develop a relationship between NCG and HHV for biomass fuels on a dry basis. A hydrogen content value representative of many wood species is approximately 6% (based on dry wood, expressed as the fraction 0.06) (Browning 1975, Table VI, p. 74). A typical LHV_{solids} value for wood is 20 MJ/kg (IPCC 1997c). Therefore:

$$\begin{aligned} LHV_{solids} &= 20 \text{ MJ/kg dry wood} = HHV_{solids} - 9 \times (2.31 \text{ MJ/kg water}) \times (0.06) \\ \therefore HHV_{solids} &= 20 \text{ MJ/kg dry wood} + 9 \times (2.31 \text{ MJ/kg water}) \times (0.06) \\ &= 21.25 \text{ MJ/kg dry wood} \end{aligned} \quad (Eq. 3)$$

An approximate relationship between LHV_{solids} and HHV_{solids} can be developed using this result:

$$\therefore \frac{LHV_{solids}}{HHV_{solids}} = \frac{20}{21.25} = 0.94 \cong 0.95 \quad (Eq. 4)$$

It is important to realize that this relation is only valid when the energy contents (in terms of both HHV and LHV) are expressed in terms of the dry fuel (i.e., energy expressed in terms of biomass solids, such as 20 GJ LHV per tonne dry wood).

LHV (NCV) is used in this report. In some cases, the emission factors have been converted from HHV (GCV) units, as listed in the sources for the factors, using the approximations described above. In the Annexes, energy-related parameters are expressed in the units used by the authorities or countries that developed the information. Except where noted, the Annexes use LHV (LHV).

5.0 DETERMINING THE ORGANIZATIONAL BOUNDARIES OF THE INVENTORY

Organizational boundaries define the company for the purpose of accounting for GHG emissions. There are a large number of possible ownership arrangements, making it difficult to provide specific instructions on how to derive organizational boundaries. Perhaps the most thorough discussion of methods for determining organizational boundaries is contained in the WRI/WBCSD GHG Protocol (WRI 2004). Companies whose organizational boundaries include partially-owned or partially-controlled sources will want to obtain that document. The approach outlined in the GHG Protocol is summarized herein.

Where the allocation of GHGs is specified contractually, that allocation is to be used. Otherwise the GHG Protocol suggests that allocation be done in one of two ways: according to control or according to equity share. Of course, if the reporting company owns all of the operations considered in the inventory the organizational boundaries will be the same when determined by either approach. The GHG Protocol also outlines different selection criteria that will facilitate the choice of approach, including consistency with financial accounting (WRI 2004).

After the organizational boundaries of the company have been determined, operational boundaries categorize direct and indirect emissions using the approach chosen under organizational boundaries (i.e., either ownership or control). The situation is usually straightforward for the consumption of purchased electricity or steam because the emissions are usually from sources outside the company's ownership and control and are, therefore, indirect.

Companies using these calculation tools may encounter situations where the inventory includes emission sources from which only a portion of the emissions will be reported (or "consolidated") as direct emissions at the corporate level, as they are from operations or companies jointly owned or controlled. In other cases (e.g., outsourced operations that are not owned or controlled) emissions might be reported fully as indirect. Some examples include:

- combined heat and power operations where the plant is a partial owner of the generating facilities
- power islands that are owned, at least in part, by other corporate entities
- wastewater treatment or landfill operations owned or operated by third parties
- plants where multiple parties share ownership of the facility

6.0 IDENTIFYING WOOD PRODUCTS MANUFACTURING OPERATIONS TO BE INCLUDED WITHIN THE INVENTORY

A table is included in this report (Table 11) which can be used to document the operations included in the inventory. Companies may use other formats to summarize this information, but a description of the inventory boundaries and the operations included in the inventory can be very helpful in interpreting the results and is recommended.

Considerations involved in setting organizational boundaries and in assigning ownership and control of emissions (i.e., setting organizational boundaries) are addressed in many protocols, including the WRI/WBCSD GHG Protocol (WRI 2004a).

Examples of wood products manufacturing operations with the potential to emit greenhouse gases include:

- power boilers, gas turbines, and other combustion devices producing steam and/or power for the plant
- incinerators and fossil fuel-fired emission control devices
- fossil fuel direct-fired and biomass fuel direct-fired dryers
- fossil fuel- or biomass-fired lumber kilns
- anaerobic wastewater treatment or sludge digestion operations (usually included in the boundaries of the inventory only if on-site or owned by the company)
- landfills used to dispose of plant wastes (usually included in the boundaries of the inventory only if on-site or owned by the company, i.e., Scope 1, but may be used to estimate Scope 3 emissions if that is consistent with the objectives of the inventory)
- on-site vehicles and machinery
- harvesting equipment used to supply the plant (usually included in the boundaries of the inventory only if owned or controlled by the company)
- trucks used to transport raw materials, products, or wastes for the plant (usually included in the boundaries of the inventory only if owned or controlled by the company)

Examples of wood products manufacturing operations that may be associated with the *indirect* emission of greenhouse gases because they sometimes consume purchased power or steam include:

- de-barking and preparation of wood furnish
- product and material conveying devices
- normal office and building operations for plant employees
- equipment for incoming process water treatment and waste treatment
- non-fossil fuel fired emission control devices (e.g., ESPs, biofilters, etc.)

There are several types of ancillary operations that may be associated with plant facilities but in some cases are not within the organizational and operational boundaries of the inventory. The decision on whether or not to include emissions from these sources will depend on the boundaries of the inventory. Examples of these ancillary operations include:

- merchant power plants located adjacent to the manufacturing facility whose primary business is selling electricity

7.0 MATERIALITY AND INSIGNIFICANT EMISSIONS

Greenhouse gas protocols generally allow facilities to ignore emissions that are so small that they do not significantly impact the estimate of overall emissions. This concept of “materiality” is drawn from financial reporting, where a material difference is sometimes taken to be a discrepancy of more than 5% between reported and audited values (though this is not an absolute standard) (Loreti, Foster, and Obbagy 2001). There is no generally accepted standard, however, for materiality in GHG inventories (Loreti, Foster, and Obbagy

2001). The GHG Protocol provides the general guidance that “information is considered to be material if, by its inclusion or exclusion, it can be seen to influence any decisions or actions taken by users of it” (WRI 2004). The GHG Protocol continues this discussion, “while the concept of materiality involves a value judgment, the point at which a discrepancy becomes material (materiality threshold) is usually pre-defined. As a rule of thumb, an error is considered to be materially misleading if its value exceeds 5% of the total inventory for the part of the organization being verified.” However, “a materiality threshold is not the same as de minimis emissions, or a permissible quantity of emissions that a company can leave out of its inventory.” It also observes that “in order to utilize a materiality specification, the emissions from a particular source or activity would have to be quantified to ensure they were under the threshold. However, once emissions are quantified, most of the benefit of having a threshold is lost” (WRI 2004).

These tools contain no specific recommendations on how to determine whether emissions are so small that they can be omitted without causing a material discrepancy in a GHG inventory, but the tools do contain emission factors and example calculations that may aid companies in deciding which emissions are material for the purpose of reporting and which are not. The decision on whether, or how, the estimates should be reported must be left to the company or may depend on who it is reporting to. That decision may depend, in part, on a company’s assessment of the quality of the data used to develop the estimate and the intended use of the inventory results. In the results of the inventory, however, companies should justify any exclusions of emissions based on materiality considerations. Furthermore, it is important to recognize that if several minor emission sources are omitted from the inventory, each of which were determined to be immaterial, the cumulative effect may affect the inventory by over 5% and thus be a material omission.

Table 1 has been developed from representative emission factors discussed in this report and its annexes. The information may assist companies in determining which sources must be included in the inventory and which are so small that they can be ignored. Subsequent sections of this report provide emission factors from the IPCC and other references. The factors in Table 1 clearly illustrate the importance of CO₂ emissions from fossil fuel combustion. In most cases, CH₄ and N₂O contribute relatively small quantities to a plant’s GHG emissions, even on a CO₂-equivalents basis. In addition, sources other than fossil fuel combustion will be comparatively small. Example calculations presented in Annexes I and J may be helpful in identifying insignificant sources. The ultimate decision on which emissions to include, however, must be made by the company or may be specified in the GHG reporting program guidance.

Table 1 does not include CO₂ from biomass combustion because, under the GHG Protocol, this CO₂ is not included in GHG totals but is reported separately as in national GHG inventories.

Table 1. Emission Factor Ranges Useful in Identifying Significant and Insignificant Sources of GHGs[†]

	Units	Fossil-CO ₂	CH ₄ (CO ₂ -equiv)*	N ₂ O (CO ₂ -equiv)*	Tables in Report Containing Values
Natural gas used in boilers	lb CO ₂ -equiv/MMBtu (HHV)	117 – 119	.0272 – .746	.0648 – 1.30	2, 5, 6
Residual oil used in boilers	lb CO ₂ -equiv/MMBtu (HHV)	168 – 172	.0287 – .139	.206 – 3.43	2, 5, 6
Coal used in boilers	lb CO ₂ -equiv/MMBtu (HHV)	205 – 278	.0332 – .650	.343 – 65.9	2, 5, 6
Bark and wood residual fuels	lb CO ₂ -equiv/MMBtu (HHV)	0	<.0464 – 1.90	<.685 – 17.8	5, 6
Diesel fuel used in vehicles	lb CO ₂ -equiv/MMBtu (HHV)	164 – 166	.181 – .511	1.37 – 21.6	8, 9
Gasoline in non-road mobile sources and machinery – 4-stroke engines	lb CO ₂ -equiv/MMBtu (HHV)	153 – 166	.186 – 68.3	.206 – 5.7	9
Gasoline in non-road mobile sources and machinery – 2-stroke engines	lb CO ₂ -equiv/MMBtu (HHV)	153 – 166	21.8 – 358	.274 – 1.90	9
Anaerobic wastewater treatment	lb CO ₂ -equiv/lb COD treated	0	5.25 ^η	0	Eq. 7, 8
Mill solid waste landfills	lb CO ₂ -equiv/dry ton solid waste	0	5,250 [∞]	0	Eq. 4, 5, 6 and Table 10

[†] last column indicates which tables later in this report contain more detailed information (because emission factors in this table are condensed from more detailed sources, they are not recommended for use in developing emissions inventories)

* CO₂-equivalents are calculated from IPCC Global Warming Potentials (CH₄ = 21 and N₂O = 310)

^Θ reported N₂O emission factors greater than 3.32 lb CO₂-equiv/MMBtu (HHV) are generally limited to fluidized bed boilers

^η assumes no capture of gas from the treatment plant

[∞] assumes that 50% of landfilled waste is degradable organic carbon, 50% of the degradable organic carbon degrades to gas, 50% of the carbon in the gas is contained in methane, none of the methane is oxidized in the landfill cover or captured, and all is released in the same year that the waste is landfilled (this method is used here only to generate an emission factor for considering whether to include this source in the inventory; more refined methods, which will normally yield lower estimates of emissions, are explained in the calculation tools)

In the results of the inventory, companies should identify situations where emissions have been estimated to be too small to materially impact the inventory results. The example reporting format presented in this report allows these situations to be identified by reporting these releases as “non-material” or “NM” in the results. Companies should also indicate in the results the criteria used to decide whether emissions are non-material. A footnote can be added, for instance, indicating that the emissions are non-material because they represent less than a certain percent of the plant’s or company’s direct emissions.

8.0 GREENHOUSE GAS EMISSIONS FROM STATIONARY FOSSIL FUEL COMBUSTION

8.1 Carbon Dioxide

Carbon dioxide emissions from stationary fossil fuel combustion represent the majority of GHG emissions for most wood products plants. Emissions of CO₂ are estimated from the carbon content of, or emission factors for, all fossil fuels being burned. In some cases, a correction (i.e., a reduction) is made for unoxidized carbon. Companies can use data from one of these sources, with the preferred sources listed first:

- data on the specific fuels being used at the plant
- the most appropriate data recommended by national authorities
- the most appropriate data available from other sources, such as the IPCC

It is prudent to recognize that the intended purpose of the emissions inventory may influence the required level of resolution of the emission estimates, and thus the required specificity of the emission factors used (i.e., an inventory developed for internal company use may not require the same accuracy and resolution as an inventory developed for participation in an emissions trading program).

Where possible and appropriate, it is preferable to obtain emission factors for fuels combusted at the facility, which are often available from the fuel vendor. This may be particularly important for coal, as the carbon, moisture, and ash contents and the heating values for differing grades of coal can vary widely. Emission factors for natural gas may also vary, depending upon, among other factors, whether or not non-methane hydrocarbons have been stripped from the raw gas. CO₂ emission factors and information on fossil fuel carbon content and unoxidized carbon are available from most national authorities and a variety of existing protocols. Some of this information is included in Annex A to this report. In cases where the Annex contains both country-specific information and IPCC information, the country-specific information may be preferred because it may reflect country-specific data on fuel carbon content. IPCC generic (Tier 1) emission factors are shown in Table 2 (converted from a LHV basis using the relation discussed in Section 4.3.2).

To correct CO₂ emission estimates for unoxidized carbon, IPCC recommends default correction factors of 0.98 for coal, 0.99 for oil and oil products, 0.995 for gas, and 0.99 for peat (non-household use combustion) (IPCC 1997c). The IPCC emission factors in Table 2 are presented as uncorrected and as corrected for unoxidized carbon based on these recommendations. IPCC points out, however, that in the case of coal, unoxidized carbon can be much higher than the default values and cites an Australian study of coal-fired boilers

wherein unoxidized carbon ranged from 1 to 12% of the carbon fed to the boiler. Unfortunately, there is not a consensus among different GHG accounting and reporting protocols with respect to the most appropriate correction factors for unoxidized carbon, as illustrated by the information in Table 3. Unless stated otherwise, the factors and example calculations presented in these tools incorporate corrections for unoxidized carbon based on IPCC recommendations.

Table 2. IPCC Default CO₂ Emission Factors for Fossil Fuels (after IPCC 1997b)

Fossil Fuel	Uncorrected Emission Factor*		Emission Factor Corrected for Unoxidized Carbon	
	kg CO ₂ /TJ (HHV)	lb CO ₂ /MMBtu (HHV)	kg CO ₂ /TJ (HHV)	lb CO ₂ /MMBtu (HHV)
Crude oil	69,700	162	69,000	160
Gasoline	65,800	153	65,200	152
Kerosene	68,300	159	67,600	157
Diesel oil	70,400	164	69,700	162
Residual fuel oil	73,500	171	72,800	169
LPG	59,900	139	59,300	138
Petroleum coke	95,800	223	94,800	221
Anthracite coal	93,400	217	91,500	213
Bituminous coal	89,900	209	88,100	205
Sub-bituminous coal	91,300	212	89,400	208
Lignite	96,100	224	94,200	219
Peat	101,000	234	99,700	232
Natural gas	50,500	117	50,200	117

* these factors assume no unoxidized carbon; to account for unoxidized carbon, IPCC suggests multiplying by these default factors: coal = 0.98, oil = 0.99, and gas = 0.995 (factors presented in the table are rounded to three significant figures)

Table 3. Recommended Correction Factors for Unoxidized Carbon from Various Guidance Documents

Source	Coal	Oil	Natural Gas
IPCC (1997c)	98%	99%	99.5%
Environment Canada (2002)*	99%	99%	99.5%
EPA Climate Leaders (USEPA 2003)	99%	99%	99.5%
DOE 1605b (USDOE 1994)	99%	99%	99%
EPA AP-42 (USEPA 1996, 1998a,b,c)	99%	99%	99.9%

* The emission factors presented in VCR (2003) do not specify correction factors for unoxidized carbon, however all emission factors presented in VCR (2003) are drawn from Environment Canada 2002

In many cases, total CO₂ emissions from all sources burning a single fossil fuel at a manufacturing facility can be estimated without estimating the emissions from each combustion unit separately. For instance, if a plant is burning natural gas in a boiler for steam production and in several dryers, the CO₂ emissions from natural gas burning can be estimated from the total gas consumed, which can be determined from fuel metering devices or from facility purchasing records. In fact, many wood products plants lack the fuel metering devices that would be required to estimate emissions from each unit separately.

NCASI has access to data which indicate that in some natural gas-fired combustion devices such as gas-fired dryers, and emission control devices such as Regenerative Catalytic Oxidizers (RCOs) and Regenerative Thermal Oxidizers (RTOs), but not power boilers, a portion of the fuel may not be combusted but rather can exit the combustion device with the emissions as methane. This condition may exist in combustion devices that operate with low burner temperatures (the autoignition temperature of natural gas is approximately 1000°F, and combustion temperatures of approximately 1475°F are required to achieve 99% combustion efficiency (Lewandowski 2000)), in situations where the burner is operated at heat input rates below or at the low end of its design operating range, or in devices where the natural gas burners are damaged or poorly maintained. Data provided to NCASI indicate that unburned methane entering an RCO either from the process or from a natural gas burner within the RCO will pass through uncombusted because the catalyst does not oxidize methane at the normal operating temperature of an RCO. Natural gas in emissions from the process are typically oxidized in an RTO, where operating temperatures are above the autoignition temperatures of methane. However, natural gas-fired RTOs operated in fuel mode (where natural gas is injected into the inlet of the RTO along with the process gases being controlled) may emit higher levels of uncombusted methane than those operated in burner mode (where natural gas is combusted in the burner(s) of the RTO). This effect can be more pronounced in RTOs that operate without a purge cycle. The data currently available to NCASI indicate that the amounts of unburned methane are highly variable.

Under most circumstances, companies will estimate CO₂ emissions at wood products manufacturing facilities by using fuel consumption (activity) data in combination with the most appropriate emission factor. If a company has reliable information on methane emissions from natural gas-fired combustion devices (e.g., emission testing results) it may use this information to adjust the emission factor-derived estimates of CO₂ emissions to account for the unburned fuel. Example calculations illustrating how to make these adjustments can be found in Annexes I and J (calculations I13 and J13).

Municipal solid waste (MSW) or materials derived from MSW are sometimes used as fuel. MSW contains a combination of fossil carbon (primarily in plastics) and biomass carbon (primarily in paper and food waste). IPCC recommends that the composition of the MSW (i.e., its fossil carbon content) be used to estimate emissions of fossil-CO₂. Where no other data are available, IPCC recommends assuming that 16% of the wet weight of MSW is fossil carbon and 5% of the fossil carbon is unburned (IPCC 2000a). These combined assumptions yield a fossil-CO₂ emission factor of 557 kg CO₂/wet tonne MSW burned.

8.1.1 Combustion of Resin-Containing Wood Residuals

Some wood products plants burn wood residuals that contain resins formulated from petroleum or natural gas raw materials. These resin-containing wood residuals originate from trim and sander dust that is often collected and burned for energy recovery. Carbon dioxide emitted from combustion of biomass fuels, such as wood and wood residuals, is not included in GHG inventory results (see Section 9.1). However, CO₂ emissions from burning the resins in these fuels can be included in the inventory results if the resins are formulated from fossil fuel-based raw materials. It is important to realize that some resins are formulated from methanol, which in turn was produced from agricultural (biomass) feedstocks. In these cases, the CO₂ from resin combustion would not be included in the GHG inventory results.

In order to estimate emissions from resin-containing wood residuals, information on the carbon content of the resin and the amount of resin added to the wood are required. Information on the carbon content of the resin may be obtained from the manufacturer or vendor or from its material safety data sheet (MSDS). Carbon content can sometimes be computed from the resin's molecular formula. However, some resin formulations release water and other gases as they cure, so it is important to use a chemical formula that represents the cured resin when calculating the carbon content in this fashion.

Some of the more common resins used in the forest products industry are urea formaldehyde (UF), phenol formaldehyde (PF), melamine formaldehyde (MF), melamine urea formaldehyde (MUF), methylene di-p-phenyl diisocyanate (MDI), and waxes. Table 4 contains representative carbon content information for these resins in their cured forms, determined by curing resin samples and analyzing for carbon (unpublished memo from P. Dopico, Georgia-Pacific Corporation, March 11, 2004).

Table 4. Carbon Content and CO₂ Emission Factors for Commonly Used Resins

Resin	Weight Percent Carbon (cured resin, assume can vary by ±10%)	Cured Resin Emission Factor (lb CO ₂ /lb cured resin)
Urea formaldehyde (UF)	31	1.1
Phenol formaldehyde (PF)	54	2.0
Melamine formaldehyde (MF)	31	1.1
Melamine urea formaldehyde (MUF)	31	1.1
Methylene di-p-phenyl diisocyanate (MDI)	72 ^{a,b}	2.6
Waxes	86 ^{a,c}	3.2

^a MDI and waxes do not evolve chemicals during curing, so it is appropriate to estimate carbon content based on their chemical formulae

^b based on chemical formula, C₁₅H₁₀N₂O₂

^c based on chemical formula, approximated by CH₂

The amount of resin on the wood residuals should be characterized as the quantity of **cured** resin on the wood. This quantity is the resin application percentage, as is typically stated in the industry. If this information is not available, it may be necessary to assume that the

amount of cured resin in the wood residuals is equivalent to the amount of uncured resin added to the wood furnish. Once the carbon content of the resin and the amount of resin added to the wood are known, an emission factor for the resinated wood residuals can be developed. An example is provided herein, computed in two ways: using a resin emission factor as provided in Table 4; and using the carbon content of the resin.

Example based on resin emission factor:

Amount of cured resin on wood residuals: 2.5% by weight (dry basis)
 Emission factor of cured resin: 1.1 lb CO₂/lb cured resin
 Wood residuals CO₂ emission factor:

$$\left(\frac{0.025 \text{ lb resin}}{1.025 \text{ lb resinated wood (dry basis)}} \right) \times \left(\frac{1.1 \text{ lb CO}_2}{1 \text{ lb cured resin}} \right) = 0.027 \text{ lb CO}_2/\text{lb resinated wood residuals (dry basis)}$$

Example based on resin carbon content:

Amount of cured resin on wood residuals: 2.5% by weight (dry basis)
 Carbon content of cured resin: 31% by weight
 Wood residuals CO₂ emission factor:

$$\left(\frac{0.025 \text{ lb resin}}{1.025 \text{ lb resinated wood (dry basis)}} \right) \times \left(\frac{0.31 \text{ lb C}}{1 \text{ lb resin}} \right) \times \left(\frac{44 \text{ lb CO}_2}{12 \text{ lb C}} \right) = 0.028 \text{ lb CO}_2/\text{lb resinated wood residuals (dry basis)}$$

Sometimes multiple resins are added to the furnish. In these cases, an emission factor can be developed that includes the carbon contribution from each resin. To develop an emission factor for resin-containing wood residuals, the relation in equation 5 can be used:

$$\frac{\text{lb CO}_2}{\text{lb resinated - wood}} = \left\{ \left[\left(\frac{\text{lb resin}_a}{\text{lb resinated wood}} \right) \times \left(\frac{\text{lb carbon}}{\text{lb resin}_a} \right) \times \left(\frac{44 \text{ lb CO}_2}{12 \text{ lb C}} \right) \right] + \left[\left(\frac{\text{lb resin}_b}{\text{lb resinated wood}} \right) \times \left(\frac{\text{lb carbon}}{\text{lb resin}_b} \right) \times \left(\frac{44 \text{ lb CO}_2}{12 \text{ lb C}} \right) \right] + \dots + \left[\left(\frac{\text{lb resin}_n}{\text{lb resinated wood}} \right) \times \left(\frac{\text{lb carbon}}{\text{lb resin}_n} \right) \times \left(\frac{44 \text{ lb CO}_2}{12 \text{ lb C}} \right) \right] \right\} \quad (Eq. 5)$$

where: a, b, ... n = designators for different resins incorporated into the wood furnish.

The resin-containing wood residuals emission factor can then be used to estimate CO₂ emissions by multiplying the amount of resin-containing wood residuals combusted by the calculated emission factor.

At some facilities, such as particleboard plants, it is common practice to add differing amounts of resins to the furnish used for the core of the panel and to the furnish used for the surface of the panel. In these situations, sander dust (which only contains material from the surface of the panel) may contain different amounts of resin than trim (which contains material from the surface and the core of the panel). An example of this situation could occur at plywood plants, where sander dust may have no resin, whereas trim will contain resin. If the amount of resin in the sander dust is vastly different than the amount in the trim, the facility may want to develop separate emission factors for sander dust and trim, and estimate emissions from each type of wood residual fuel separately.

8.2 Methane and Nitrous Oxide

Methane and nitrous oxide emissions from fossil fuel combustion are usually very small compared to CO₂ emissions. Indeed, some inventory protocols, including the WRI/WBCSD GHG Protocol, do not address CH₄ and N₂O from fossil fuel combustion. Because some inventories include CH₄ and N₂O, however, they are addressed in these calculation tools.

Companies will often be able to use the data in Table 1 to demonstrate that emissions of CH₄ and N₂O from fossil fuel combustion are insignificant compared to CO₂ emissions. In other cases, a single emission factor might be available that includes fossil-CO₂, CH₄, and N₂O emissions expressed as CO₂-equivalents. In this case, the company may not need to report the three gases separately. As noted in Section 8.1, however, some types of combustion units at wood products plants (not including power boilers) have the potential to emit unburned natural gas (methane, in particular) in larger quantities than suggested by power boiler emission factors. This is discussed in more detail in Section 8.2.2.

Estimating CH₄ and N₂O emissions will usually involve selecting the emission factors best suited to the fuels being burned and the type of combustion unit. For normal fossil fuel-fired combustion devices, recommended emission factors follow this order of preference:

- data on the specific fuels and combustion devices being used at the plant
- the most appropriate data recommended by national authorities
- the most appropriate data available from other sources

It is prudent to recognize that the intended purpose of the emissions inventory may influence the required level of resolution of the emission estimates, and thus the required specificity of the emission factors used (i.e., an inventory developed for internal company use may not require the same accuracy and resolution as an inventory developed for participation in an emissions trading program).

A number of existing protocols and most national authorities publish factors for estimating emissions of CH₄ and N₂O from fossil fuel-fired boilers and other combustion devices. Many of these emission factors are listed in Annex A to these tools.

IPCC provides Tier 1 and Tier 2 emission factors for methane and nitrous oxide. The Tier 1 method for estimating emissions is described by IPCC as one in which emissions from all sources of combustion (of a particular fuel) are estimated on the basis of the (total) quantities of fuel consumed and average emission factors (IPCC 1997b,c). IPCC describes the Tier 2

method as one in which emission estimates are based on detailed fuel and technology information. In other words, a Tier 1 analysis could be performed based on facility-level fuel consumption data, whereas a Tier 2 analysis would require source by source fuel consumption data and associated source-specific emission factors. As an example of a Tier 1 approach, a plant combusting natural gas in one boiler, one dryer, and one RTO estimates emissions by summing the total natural gas used in these three devices and multiplying this quantity by an emission factor for natural gas. An example of a Tier 2 approach for the same facility would be to estimate emissions from the boiler by multiplying the boiler fuel consumption by an emission factor developed specifically for that type of boiler, estimate emissions from the dryer using the dryer fuel consumption data and an emission factor developed for that type of dryer, and so on. The Tier 2 method is more detailed than the Tier 1 method, and if source-specific fuel consumption data and emission factors are available the Tier 2 method may return more accurate results than the Tier 1 method.

IPCC's Tier 1 emission factors for methane and nitrous oxide are presented in Table 5. IPCC's Tier 2 emission factors, shown in Table 6 for many of the fossil fuels and combustion devices of interest to the forest products industry, are usually preferred because they are more specific to fuel type and combustion device. Unfortunately, IPCC does not provide emission factors for some production and emissions control equipment (e.g., dryers, RTOs, etc.). In these cases, use of the Tier 1 factors may be more appropriate.

Table 5. IPCC Tier 1 CH₄ and N₂O Emission Factors for Stationary Combustion*
(from IPCC 1997c)

	CH ₄ Emission Factors		N ₂ O Emission Factors	
	lb/MMBtu HHV	kg/TJ HHV	lb/MMBtu HHV	kg/TJ HHV
Coal	0.02	10	0.0031†	1.3†
Natural gas	0.01	5	0.0002	0.1
Oil	0.004	2	0.001	0.6
Wood/wood residuals	0.07	30	0.009	4

* converted from a basis of LHV to HHV using the IPCC recommended multipliers 0.90 for natural gas and 0.95 for all other fuels; rounded to one significant digit, unless noted otherwise

† rounded to two significant digits

Both the Tier 1 and the Tier 2 emission factors for methane and nitrous oxide are based on uncontrolled emissions. This is unimportant for methane because most emission control devices have little impact on methane emissions (IPCC 1997c) (exceptions may include thermal oxidizers such as RTOs, which under some operating configurations can oxidize methane). Nitrous oxide emissions can be impacted by control devices, but the data are very limited (IPCC 1997c). Where N₂O emissions are important to inventory results, companies may want to develop emissions data. In most cases, however, the difference between controlled and uncontrolled emissions is expected to have little effect on total GHG emissions. Therefore, companies will probably want to use the Tier 1 or Tier 2 emission factors shown in Tables 5 and 6 unless other factors that are more suited to individual plant circumstances are available.

Methane and nitrous oxide emission factors for stationary internal combustion engines (e.g., those used to drive emergency generators or turbines) fired with diesel or gasoline can be approximated by the factors for non-road mobile sources shown in Table 8.

Fossil fuels can be used in a number of different combustion units common in the forest products industry. Some specific recommendations for estimating CH₄ and N₂O emissions from certain types of units found exclusively or primarily in the forest products industry are shown herein.

Table 6. IPCC Tier 2 Uncontrolled CH₄ and N₂O Emission Factors for Industrial Boilers (from IPCC 1997c)

Fuel	Technology/Configuration	CH ₄ Emission Factors		N ₂ O Emission Factors	
		lb/MMBtu (HHV)	kg/TJ (HHV)	lb/MMBtu (HHV)	kg/TJ (HHV)
Bituminous coal	Overfeed stoker boilers	0.002	0.95	0.0035	1.5
Sub-bituminous coal	Overfeed stoker boilers	0.002	0.95	0.0035	1.5
Bituminous coal	Underfeed stoker boilers	0.031	13	0.0035	1.5
Sub-bituminous coal	Underfeed stoker boilers	0.031	13	0.0035	1.5
Bituminous coal	Pulverized/dry bottom, wall fired	0.0015	0.7†	0.0035	1.5
Bituminous coal	Pulverized/dry bottom, tangentially fired	0.0015	0.7†	0.001	0.5†
Bituminous coal	Pulverized/wet bottom	0.002	0.9†	0.0035	1.5
Bituminous coal	Spreader stoker	0.002	0.95	0.0035	1.5
Bituminous coal	Fluidized bed/circulating or bubbling	0.002	0.95	0.21	91
Sub-bituminous coal	Fluidized bed/circulating or bubbling	0.002	0.95	0.21	91
Anthracite		0.02*	10*†	0.0031*	1.3*
Residual oil		0.007	2.9	0.0007	0.3†
Distillate oil		0.0004	0.2†	0.0009	0.4†
Natural gas	Boilers	0.0029	1.3	0.0002*	0.1*†
Natural gas	Turbines	0.001	0.5	0.0002*	0.1*†
Natural gas	Int. combustion engine/ 2-cycle lean burn	0.036	15	0.0002*	0.1*†
Natural gas	Int. combustion engine/ 4-cycle lean burn	0.027	12	0.0002*	0.1*†
Natural gas	Int. combustion engine/ 4-cycle rich burn	0.0061	2.6	0.0002*	0.1*†

* IPCC Tier 1 generic emission factors for coal and natural gas; Tier 2 emission factors are not available

† due to rounding to the appropriate number of significant digits, the factor in terms of HHV is numerically equivalent to the factor as provided in IPCC 1997c in terms of LHV

8.2.1 Combination Fuel-Fired Boilers Burning Biomass and Fossil Fuels

Methane and nitrous oxide releases from boilers are sensitive to combustion conditions, especially combustion temperature. In most cases, the combustion conditions in combination fuel boilers are more like those in biomass-fired boilers than in fossil fuel-fired boilers.

Therefore, unless data are available from site-specific testing on similar boilers burning a comparable mix of fuels, it is recommended that the CH₄ and N₂O emissions from combination fuel-fired boilers be estimated from the total heat input to the boiler and CH₄ and N₂O emission factors for biomass. These emission factors are summarized in Section 9.2.

In some cases, a facility may operate a combination fuel boiler where fossil fuel comprises a major portion of the total fuel to the boiler. Although estimating CH₄ and N₂O emissions using the approach outlined in the previous paragraph is appropriate in these cases, it is also valid to estimate these emissions based on consumption rates of each fossil fuel multiplied by the fuel's emission factors, plus the consumption rate of biomass fuel multiplied by the biomass fuel's emission factors.

8.2.2 *Production and Emission Control Devices, Incinerators, and Other Miscellaneous Sources*

Some combustion devices and production equipment at wood products plants may emit levels of CH₄ and/or N₂O that are difficult to estimate based on fuel consumption using a Tier 2 approach. The difficulty arises from three potential sources. First, certain combustion sources at some wood product plants (e.g., natural gas-fired dryers) often lack fuel metering devices, so amounts of fuel combusted in the particular combustion device are not known. Second, there are no published Tier 2 emission factors for methane emissions from burners in gas-fired veneer or lumber dryers or from RCO or RTO burners. Third, the emissions from some combustion sources are controlled by operations which are also combustion sources, and these emission control devices may alter the GHG emission profile of the original combustion source (e.g., natural gas-fired dryers whose emissions are controlled by RTOs that also burn natural gas). Thus, it may be appropriate in some cases to estimate emissions based on a Tier 1 method, using facility-level fuel consumption data and Tier 1 emission factors (Table 5). Alternatively, where CH₄ and N₂O emissions are important to inventory results, companies may want to develop emissions data.

However, as discussed in Section 8.1, some types of natural gas-fired production and emission control devices at wood products facilities (e.g., direct natural gas-fired dryers and RTO/RCOs) may, for a variety of reasons, emit a portion of the fuel (methane), uncombusted, to the atmosphere. The limited data available to NCASI at this time indicate that, in some situations, this can result in methane emissions from natural gas fired dryers and emission control devices which are several times higher than predicted by Tier 1 methane emission factors. Furthermore, some companies have reported that the catalysts used in RCOs do not readily catalyze methane oxidation. Therefore, any methane in the gas stream controlled by RCOs may pass through the RCO and be emitted to the atmosphere.

Unfortunately, the case-specific nature of this phenomenon and a lack of emissions data preclude development of emission factors specific to direct natural gas-fired dryers and RTO/RCOs at this time. However, if a company has reliable information on methane emissions from direct natural gas-fired combustion devices (e.g., emission testing results), it may use this information to develop emission estimates. Example calculations that illustrate

estimating emissions from these devices based on source testing results are provided in Annexes I and J (calculation I13 and J13).

8.2.3 *Summary of Guidance for Estimating Methane and Nitrous Oxide Emissions*

Based on the information in Sections 8.2 and 8.2.2, the following general guidance is provided for estimating methane and nitrous oxide emissions at wood products manufacturing facilities.

- If the facility has access to facility-level fuel consumption data only, this activity data can be used in conjunction with Tier 1 emission factors to estimate emissions.
- If the facility has access to combustion device-specific fuel consumption data, this activity data can be used with the appropriate Tier 2 (source-specific) emission factors where available, and with Tier 1 emission factors for combustion devices for which no Tier 2 factors are available (e.g., gas-fired dryers, RTOs, etc.) to estimate emissions.
- If the facility has access to methane emissions data from source testing of devices such as natural gas-fired dryers and RTOs/RCOs, this information can be used to adjust the emission estimates derived from emission factors and fuel consumption (activity) data. Example calculations are provided in Annexes I and J (calculations I13 and J13).

9.0 EMISSIONS FROM STATIONARY COMBUSTION OF BIOMASS FUELS

9.1 Releases of Biomass-Derived Carbon Dioxide from Burning Biomass Fuels

Many wood products plants generate more than half their energy needs from biomass fuels recovered from the industry's waste and process streams. The CO₂ generated when biomass fuels are burned is not included in GHG emissions totals. The GHG Protocol, however, requires that biomass-derived CO₂ be reported as additional information. This is the approach generally prescribed for national inventories by the United Nations Framework Convention on Climate Change. Therefore, in keeping with well-established practices, the GHG inventory results generated using these calculation tools do not include CO₂ emissions from biomass burning, but methods are provided for estimating biomass-derived CO₂ so that it can be reported where needed (see Annex G).

IPCC provides a list of biomass fuels (IPCC 1997a, c):

- wood and wood residuals (although biogas from wood residuals and other biomass is not specifically listed by IPCC, it clearly falls within the general definition of biomass)
- charcoal
- dung
- agricultural residues and wastes
- municipal and industrial wastes (where the organic material is biological in origin) (this would include wastewater treatment sludges from wood products plants)
- bagasse
- bio-alcohol
- black liquor
- landfill gas
- sludge gas

CO₂ emissions from peat burning are usually considered to be GHGs and they are included in the emissions from fossil fuel burning (Table 2).

Combustion of wood residuals containing resins used in the manufacturing process may result in emissions of carbon dioxide that could be considered a greenhouse gas (e.g., CO₂ from the oxidation of fossil-derived resins). This topic is discussed in detail in Section 8.1.1

Annexes I and J contain examples of estimating CO₂ emissions from biomass fuels (see calculations I3, I11, and I12, or J3, J11, and J12).

9.2 Methane and Nitrous Oxide Emissions from Burning Biomass Fuels

Although CO₂ from biomass burning is almost universally excluded from GHG inventories, CH₄ and N₂O from biomass burning are sometimes included because these gases do not participate in the atmospheric CO₂ sequestration-recycling process explained in Section 9.1. Calculation tools are provided, therefore, to assist in estimating these emissions.

If a company has reliable site-specific data allowing it to estimate CH₄ and N₂O emissions from biomass combustion, it should use those data. Otherwise, it will be necessary to use the most appropriate emission factors available. Unfortunately, there are few data on CH₄ and N₂O emissions from biomass combustion. Some of the available emission factors are shown here and discussed in more detail in Annex B.

IPCC's Revised 1996 Inventory Guidelines used emission factors developed by EPA. This is also true for a number of countries. EPA has since revised these factors (USEPA 2001). Even the updated EPA factors, however, are based on very few data. Table 7 provides a summary of the available information on methane and nitrous oxide emissions from biomass boilers. The IPCC Tier 1 emission factors for combustion of "wood, wood residuals, and other biomass and wastes" are also shown in Table 7. The many individual country factors that are based on IPCC or EPA factors are not shown. The variability in the data reflects the many different types and ages of boilers tested, operating conditions, control equipment, and fuel characteristics. (Many of the values in Table 7 were provided in terms of LHV by the referenced source, and were converted to terms of HHV using the multiplier 0.95.)

Where an emission factor shown in Table 7 was developed for circumstances that match conditions at a plant, the company may want to select that emission factor for estimating emissions. For instance, companies with fluidized bed boilers may want to use the Fortum emission factors because they were developed on fluidized bed boilers while the other emission factors were developed on stoker boilers or on boilers of an unspecified design. In many cases, however, because of the ranges in emission factors and the limited ability at this time to match emission factors to boiler designs, operating conditions, and fuels, it is reasonable to use the median emission factors shown in the table to characterize emissions from boilers. These median emission factors fall within the ranges cited in the CORINAIR emissions inventory (ranges also shown in the table) (EEA 1999). For wood-fired combustion equipment other than boilers (e.g., direct-fired dryers, etc.), it may be most appropriate to use the IPCC Tier 1 emission factors shown in Table 7. In some cases, a

facility may choose to base emission estimates on facility-level fuel consumption data in conjunction with the Tier 1 emission factors.

Table 7. Emission Factors for CH₄ and N₂O from Biomass Combustion

Emission Factor Description	CH ₄ Emission Factors		N ₂ O Emission Factors		Reference
	lb/MMBtu (HHV)	kg/TJ (HHV)	lb/MMBtu (HHV)	kg/TJ (HHV)	
Wood residual fuel-fired boilers					
Wood, wood residuals, and other biomass and wastes	0.07	30†	0.009	4†	Tier 1 – IPCC 1997c
Uncontrolled emissions from wood-fired stoker boilers	0.033	14	–	–	Tier 2 – IPCC 1997c
Average for wood residue combustion	0.021	9.0	0.013	5.6	USEPA 2001
Average for circulating fluidized bed boilers burning peat or bark	0.002	1†	0.019	8.4	Fortum 2001
Average for bubbling fluidized bed boilers burning peat or bark	0.004*	2*†	<0.004	<2†	Fortum 2001
Pre-1980 wood residue-fired stoker boilers sampled ahead of control devices	0.018	7.8	–	–	NCASI 1980
Pre-1980 wood residue-fired stoker boilers sampled after wet scrubbers	0.0060	2.6	–	–	NCASI 1985
Wood fired boiler	0.091 ^λ	39 ^λ	0.0069 ^λ	2.9 ^λ	JPA 2002
Wood as fuel	0.053 ^λ	23 ^λ	0.0075 ^λ	3.2 ^λ	AEA 2001
Wood residuals	0.07	30†	0.01	5†	Swedish EPA 2001
Median emission factors for wood residuals	0.027	11	0.009	4†	
	0.0-0.09	1-40†	0.0031-0.17	1.3-71	EEA 1999

† due to rounding to the appropriate number of significant digits, the factor in terms of HHV is numerically equivalent to the factor as provided in the original reference source in terms of LHV

* excludes one very high number associated with low oxygen-high carbon monoxide conditions

λ based on heat content of 21.1 GJ (HHV)/tonne (18.1 MMBtu (HHV)/ton) dry solids

It is recognized that some wood-derived fuels burned in wood products manufacturing facilities have higher nitrogen contents than typical wood residuals, due to inclusion of resins which can contain nitrogen compounds. However, given the combustion conditions in the units burning these fuels there is little reason to suspect significant formation of N₂O from this fuel-nitrogen.

Annexes I and J contain examples of estimating CH₄ and N₂O emissions from biomass fuels (see calculations I3, I11, and I12, or J3, J11, and J12).

9.2.1 *Combination Fuel-Fired Boilers Burning Biomass and Fossil Fuels*

As discussed in Section 8.2.1, methane and nitrous oxide releases from boilers are sensitive to combustion conditions, especially combustion temperature. In most cases, the combustion conditions in combination fuel boilers are more like those in biomass-fired boilers than fossil fuel-fired boilers. Methane and nitrous oxide emissions are often more directly related to combustion conditions than to fuel type. Because of the high moisture content of most wood-based fuels, a reasonable default is to assume that the combustion conditions in combination fuel-fired boilers reflect the impact of the wood residual fuels. Therefore, unless data are available from site-specific testing on similar boilers burning a comparable mix of fuels, or unless the combustion conditions in the combination fuel-fired boiler are more like fossil fuel-fired boilers than wood residual fuel boilers, it is recommended that the emissions from combination fuel-fired boilers be estimated from the total heat input to the boiler and CH₄ and N₂O emission factors for biomass.

In some cases, a facility may operate a combination fuel boiler where fossil fuel comprises a major portion of the total fuel to the boiler. Although estimating CH₄ and N₂O emissions using the approach outlined in the previous paragraph is appropriate in these cases, it is also valid to estimate these emissions based on consumption rates of each fossil fuel multiplied by the fuel's emission factors, plus the consumption rate of biomass fuel multiplied by the biomass fuel's emission factors.

Annexes I and J contain examples of estimating GHG emissions from combination-fired boilers (see calculations I3 and I11, or J3 and J11).

9.2.2 *“Beehive” or “Teepee” Burners*

Some companies operate “beehive” or “teepee” burners. These are combustion devices that are fired with wood residual fuels and do not incorporate any form of energy recovery. Due to a lack of data on methane and nitrous oxide emissions from these combustion sources, companies that wish to include CH₄ and N₂O emissions from these sources are advised to use the IPCC Tier 1 emission factors for wood/wood residuals (Table 7) in combination with the quantities of wood fuel fired to estimate emissions.

An example of estimating GHG emissions from beehive or teepee burners is presented in Annexes I and J (see calculation I12 or J12).

10.0 EMISSIONS ATTRIBUTABLE TO IMPORTS AND EXPORTS OF ELECTRICITY AND STEAM

The consumption of power or steam (or hot water) purchased from another company usually results in the generation of indirect emissions—i.e., “emissions that are a consequence of activities of the reporting company, but occur from sources owned or controlled by another company” (WRI 2004). Of course, virtually every raw material, energy source, and service used by a company has an indirect emissions impact. Many GHG accounting protocols, however, selectively include indirect emissions related to electrical power and steam consumption because they are applicable to a wide range of activities and can be a significant

component of a company's total GHG impact. The calculation tools presented in this report, therefore, address indirect emissions from electricity and steam (or hot water) transfers. Like most existing protocols, these tools recommend that indirect emissions be reported separately from direct emissions.

10.1 Emission Factors for Purchased Power and Steam

Electrical power companies and national authorities publish information on the emissions generated in producing electrical power on a national or regional basis, so it is relatively easy to estimate the indirect emissions associated with purchased power (sources for national and regional information are identified in Annex C). It is often difficult, however, to determine whether published emission factors for electrical power include all GHGs or only CO₂ emissions. The difference is usually unimportant because CO₂ represents the great majority of the emissions in most situations. For purposes of these calculation tools, therefore, it is assumed that purchased power emission factors address all GHGs and are reported in CO₂-equivalents. Where emission factors are available for individual gases associated with electrical power, the individual gases can be reported separately and then combined into carbon dioxide equivalents, or the individual emission factors can be combined into a single CO₂-equivalents emission factor.

Electrical power transmission losses vary from location to location. In some cases, they are so significant that they provide an important rationale for distributed power generation. However, published GHG emission factors for purchased power seldom incorporate the effects of transmission losses. The GHG Protocol, for example, states that “end consumers of ... purchased electricity do not report indirect emissions associated with [transmission and distribution] losses ... because they do not own... the [transmission and distribution] operation where the electricity is consumed ([transmission and distribution loss])” (WRI 2004). Furthermore, accepted GHG protocols seldom ask users of electrical power to account for transmission losses. Thus, these tools recommend the use of emission factors for purchased power that do not include transmission losses. If transmission losses are particularly important, however, this can be noted in the results and the impact can be estimated in supporting information.

In addition, some published emission factors for purchased power are “full fuel cycle” emission factors that include upstream emissions from fuel production. Because full fuel cycle emission factors are not the norm, these calculation tools recommend that purchased power emission factors be based only on the emissions from the power producers and not their upstream emissions. If companies must use full fuel cycle emission factors, to satisfy national reporting requirements, for instance, this should be noted in the results.

10.2 Electricity Imports

To estimate indirect emissions associated with imported power that is consumed, companies should use the most appropriate purchased power emission factor available; i.e., one that reflects the emissions generated during the production of the power being purchased. At most wood products plants, power imports are from base loads. In most cases, therefore, the base load or average emission factor should be used rather than the marginal or peak power

emission factor. Where companies can demonstrate that a peak power emission factor (or some other emission factor) is more appropriate, it can be used, but the justification should be noted in the results. In some cases, the emission factor for purchased power will reflect specific purchasing agreements with a power supplier (e.g., for “green” power).

In cases where imported power is generated by a nearby combined heat and power (CHP) system, the emissions associated with the imported power can be estimated using the method described in Section 10.7. Of course, if a manufacturing plant is using all of the heat and power from a CHP system, there is no need to allocate the emissions. In such a case, if the company owns or controls the source all the emissions will be reported as direct emissions. On the other hand, if the source is owned or controlled by another entity all the emissions will be reported as indirect emissions.

An example of estimating GHG emissions from purchased electrical power is presented in Annexes I and J (see calculation I4 or J4).

10.3 Electricity Exports

These calculation tools suggest a format for reporting results wherein a plant reports all direct emissions associated with the generation of power and steam, whether the power and steam is used internally or exported. In circumstances in which a company wants to delineate the amount of direct emissions attributable to exported power and steam, the example reporting tables provide a suggested format. The tables also suggest a format for companies to compare the carbon intensity of exported power (in kg CO₂/MWh) to the carbon intensity of the power on the grid into which the power is exported. Companies may find this helpful for highlighting the beneficial environmental attributes of exports of biomass-based power and power produced by CHP systems. Companies wanting to conform to the WRI/WBCSD GHG Protocol should not net imports and exports or the associated emissions. Electricity exports may be included in the optional information category, but emissions from the creation of electricity will still be included in the direct emissions category for the organization.

Estimating the emissions impact of exported power involves estimating the emissions generated by the plant to produce the exported power. Because exported electricity from manufacturing plants is usually generated in CHP systems, companies will often need to use the methods for CHP systems (Section 10.6) to estimate the emissions attributable to the exported power.

In the inventory results, companies can show the carbon intensity of exported power or steam (e.g., in kg CO₂/MWh or kg CO₂/GJ) compared to the carbon intensity of the grid into which the power or steam is exported. To estimate the carbon intensity of the grid, the plant should use the most appropriate grid emission factor available—i.e., one that reflects the emissions assumed to be displaced by the power being exported. Because plants usually export power into base loads (i.e., plants do not usually serve as suppliers of peaking power), the base load emission factor will be used in most cases rather than the marginal or peak power emission factor. Companies may use the peak or marginal emission factors, however, if they are more appropriate.

10.4 Steam Imports

In many cases where steam is imported by a manufacturing plant, it is produced by a nearby CHP system. In these cases, the indirect emissions reported by the plant can be estimated using the allocation method described in Section 10.7. In other cases, the contractual arrangement between the manufacturing plant and the power producer may define how the emissions from the power plant are to be allocated between the power and the steam sold by the power plant. In these cases, the allocation should be explained in the results. If the imported steam is not generated in a CHP system, best professional judgment must be used to estimate the emissions reported by the wood products manufacturing plant. In these calculations, the heat delivered to the plant can be adjusted to reflect the amount of heat in returned condensates. The method used to estimate the indirect emissions associated with imported steam should be described in the results of the inventory.

10.5 Steam and Hot Water Exports

As in the case of electricity, the total on-site emissions from company-owned boilers are shown as direct emissions whether steam or hot water is exported or not, but the emissions associated with exported steam or hot water can be shown separately. For example, in the GHG Protocol this information can be provided in the optional information section. The method for estimating these emissions is analogous to the method used for exported electricity. The method used to develop the estimate will depend on whether a CHP system is involved. If steam from a boiler is exported directly without first being used in a CHP system, the emissions from the boiler can usually be allocated in direct proportion to the amount of steam exported (as a fraction of the total amount of steam generated by the boiler). If, however, a CHP system is involved, the method described in Section 10.7 should be used to allocate emissions. In either case, the heat delivered by the plant can be adjusted to reflect the amount of heat in returned condensates. A variety of situations will require the use of best professional judgment. Exports of hot water are treated the same as exports of steam, on an energy content basis (i.e., one GJ of hot water energy is assumed to be equivalent to one GJ of steam energy, thermal losses during generation of hot water from plant-generated steam are assumed to be negligible).

10.6 Allocating Emissions from Combined Heat and Power (CHP) Systems

Where electricity is produced by combined heat and power (CHP) systems, it may be necessary to allocate the emissions from the CHP system to the various output energy streams. Of course, if the manufacturing plant owns the CHP system and uses all of its output, allocation is not necessary because all of the emissions are direct emissions for the plant. In many cases, however, a plant may either receive CHP energy from an outside provider or export a portion of its own CHP output. For instance, if a manufacturer is importing steam from a nearby power plant, it is necessary to estimate the indirect emissions associated with the imported steam. Likewise, if a manufacturer is exporting power from a CHP system but using the steam internally, one must estimate how much of the manufacturer's emissions are attributable to the exported electricity. Exports of hot water are treated the same as exports of steam.

Although there are several methods for allocating emissions from CHP systems, the “efficiency” method is recommended in these calculation tools. (Additional information on a number of different methods is presented in Annex D.) The efficiency method is recommended because it attempts to relate the energy outputs to the amounts of fuel used to generate them and, by extension, to the GHGs produced in generating them. Where a company uses an alternative method, the method should be explained in the results.

The efficiency method is one of two methods recommended by WRI/WBCSD (termed “CHP option 1” by WRI/WBCSD) (WRI 2001b, c). There are two versions of the efficiency method. The first, the simplified efficiency method, is less complex but involves several assumptions about equipment efficiencies. It is expected that the simplified method will be adequate for many wood products plants and, therefore, it is included in this report as a default method. The second, the detailed efficiency method, is more complicated but can use site-specific design and operating data that companies sometimes have for CHP systems. The detailed efficiency method is described in Annex D.

Where a manufacturing plant or company has more than one CHP system, it need not allocate the emissions from all systems using the same efficiencies for power and steam generation if there is a basis for using different efficiencies on different CHP systems.

10.6.1 *Simplified Efficiency Method*

The efficiency method requires use of assumed efficiency factors for the production of power and steam, or actual efficiency factors for each steam or power generation device based on detailed process design and operating information. It is assumed that the efficiency of producing hot water is the same as the efficiency of producing steam. The simplest approach to applying the efficiency method is to assign a single efficiency factor to all power output and a single efficiency factor to all heat (steam and hot water) output. This information is used to compute an efficiency ratio equal to the heat production efficiency divided by the power production efficiency. For example, if the CHP system produces steam at 80% efficiency and power at 40% efficiency the ratio would be 2. The efficiency ratio is used rather than the individual efficiencies because (a) it is the ratio that controls the allocation of emissions rather than the individual efficiencies, and (b) the individual efficiencies are constrained by the energy balance so it is not possible to specify both independently. Emissions from the CHP system are allocated between the heat and power outputs, based on this ratio of efficiencies, using Equations 6 and 7. This approach is referred to in this report as the simplified efficiency method. The simplified efficiency method is recommended for manufacturing facilities that lack, or choose not to use, detailed design and operating data from CHP systems.

$$E_H = \left\{ \frac{H}{H + P \times R_{eff}} \right\} \times E_T; \quad R_{eff} = \frac{e_H}{e_P} \quad (Eq. 6)$$

where: E_H = emissions share attributable to heat production, t GHG/y
 E_T = total emissions from the CHP plant, t GHG/y

H = heat output, GJ/y
 P = power output, GJ/y
 R_{eff} = ratio of heat production efficiency to power production efficiency
 e_H = assumed efficiency of typical heat production (default = 0.8)
 e_P = assumed efficiency of typical electric power production (default = 0.35)

The emission share attributable to electric power production is assigned from the relation:

$$E_P = E_T - E_H \quad (Eq. 7)$$

where: E_P = emissions share attributable to electric power production

In these calculations, the heat in steam can be corrected to reflect the amount of heat in returned condensates.

In using the simplified efficiency method, use of efficiencies of 0.35 for power generation and 0.8 for steam (or hot water) generation are recommended, corresponding to a ratio of efficiencies (R_{eff}) of 2.3. The example calculation presented in Annexes I and J makes use of these recommended default efficiency factors (see calculation I5 or J5).

11.0 GREENHOUSE GAS EMISSIONS FROM VEHICLES AND MISCELLANEOUS FOSSIL FUEL-FIRED EQUIPMENT

Companies often own vehicles to transport raw materials, products, wastes, and employees. Companies may also own off-road vehicles and other types of fossil fuel-fired equipment. Because companies may want to include these emissions in corporate GHG inventories (as recommended in the WRI/WBCSD GHG Protocol), they are addressed in these calculation tools. Companies should indicate in the results of the inventory whether these emissions have been included.

11.1 Greenhouse Gas Emissions from On-Road Vehicles

Companies wanting to include these emissions can base them on either fuel consumption statistics or information on distances traveled. Emission factors from a variety of sources allow estimates of CO₂, CH₄, and N₂O emissions from transportation vehicles (Annex E). The emission factors in Annex E clearly demonstrate, however, that CH₄ and N₂O emissions are a small fraction of CO₂ emissions from on-road transportation sources. CO₂ emission factors for liquid transportation fuels are usually close to 70 kg CO₂/GJ, while even on a CO₂-equivalents basis combined CH₄ and N₂O emission factors are approximately 0.6 kg/GJ, less than 1% of CO₂ emissions. These calculation tools address only CO₂ emissions from these sources due to the small contribution of non-CO₂ gases, which is consistent with the recommendations of the WRI/WBCSD GHG Protocol. Where it is easier, however, companies may want to use emission factors that include all GHGs in units of CO₂-equivalents.

If companies use fuel consumption statistics to estimate CO₂ emissions, the estimates are derived using the same approach as that used for stationary fossil fuel combustion sources

(Section 8). If, on the other hand, the company finds it more convenient to develop the emissions estimate from statistics on distance traveled, the emission factors in Table 8 can be used (WRI 2001d). It should be recognized, however, that use of distance-based factors may result in less accurate emission estimates than those computed based on actual fuel consumption quantities.

Table 8. Default Fuel Economy and Emission Factors for Different Types of Mobile Sources and Activity Data (from WRI 2001d)

Vehicle Characteristics			Emission Factor	
Vehicle Type	MPG*	Liters/100 km	lb CO ₂ /mile	gram CO ₂ /km
New small gas/electric hybrid	56	4.2	0.3554	100.1
Small gas auto, highway	32	7.3	0.6216	175.1
Small gas auto, city	26	9.0	0.7650	215.5
Med gas auto, highway	30	7.8	0.6631	186.8
Med gas auto, city	22	10.7	0.9042	254.7
Large gas automobile, hwy	25	9.4	0.7956	224.1
Large gas automobile, city	18	13.1	1.105	311.3
Med station wagon, hwy	27	8.7	0.7366	207.5
Med station wagon, city	20	11.8	0.9944	280.1
Mini van, hwy	24	9.8	0.8289	233.5
Mini van, city	18	13.1	1.105	311.3
Large van, hwy	18	13.1	1.105	311.3
Large van, city	14	16.8	1.421	400.2
Mid size pick-up truck, hwy	22	10.7	0.9042	254.7
Pick-up truck, city	17	13.8	1.170	329.6
Large pick-up truck, hwy	18	13.1	1.105	311.3
Large pick-up truck, city	15	15.7	1.326	373.5
LPG automobile	21	11.2	0.944	266
Diesel automobile	24	9.8	0.827	233
Gasoline light truck	14	16.8	1.420	400
Gasoline heavy truck	6	39.2	3.28	924
Diesel light truck	15	15.7	1.33	374
Diesel heavy truck	7	33.6	3.09	870
Light motorcycle	60	3.9	0.330	93
Diesel bus	6.7	35.1	3.674	1035

*MPG = miles per gallon

11.2 Greenhouse Gas Emissions from Off-Road Vehicles and Equipment

Companies may own off-road vehicles and other fossil fuel-powered equipment that they want to include in the operational boundaries of the inventory. These sources might include everything from forklifts to chain saws.

Fuel consumption statistics can be used to estimate CO₂ emissions from these sources using the emission factors in Table 2. Unlike on-road vehicles, however, CH₄ and N₂O emissions can be a notable fraction of the GHG emissions from some of these sources. N₂O emissions for some of these sources are reported to be near 30 g/GJ or 9 kg CO₂-equivalents/GJ, which can amount to more than 10% of the CO₂ emissions from such sources.

Emission factors for these sources have been published in a number of places. Some of the available information is summarized in Annex E. IPCC's guidelines contain several different sets of emission factors without recommending a single set (IPCC 1997c). Table 9 is from one of the sources cited by IPCC (Table 9a is in "English" units; Table 9b is in SI units). The CO₂ factors in the table are from Table 2 and are slightly different than those in the original table in IPCC 1997c. Table 9 also includes overall CO₂-equivalent emission factors developed using the IPCC global warming potentials for CH₄ (21) and N₂O (310). Emission factors for CH₄ and N₂O from these sources vary from one protocol to another. The differences in N₂O, in particular, can impact the CO₂-equivalents by as much as 10%. Where companies need precise estimates for these sources, it is recommended that the various sources discussed in Annex E be examined to determine which emission factors are most appropriate. In most cases, however, the emission factors in Table 9 will be adequate.

Table 9a. Fuel Consumption-Based Emission Factors ["English" units]
for Non-Road Mobile Sources and Machinery (IPCC 1997c)
(IPCC Revised 1996 Guidelines taken from EMEP/CORINAIR)

Source and Engine Type	lb CO ₂ /MMBtu (HHV)	lb CH ₄ /MMBtu (HHV)	lb N ₂ O/MMBtu (HHV)	lb CO ₂ -equiv./MMBtu (HHV)
Forestry – diesel	162*	0.009	0.066	183
Industry – diesel	162*	0.009	0.066	183
Railways – diesel	162*	0.009	0.066	183
Inland waterway – diesel	162*	0.009	0.066	183
Marine – diesel	162*	0.016	0.004	164
Industry – gasoline 4-stroke	152*	0.1	0.004	155
Forestry – gasoline 2-stroke	152*	0.38	0.0009	160
Industry – gasoline 2-stroke	152*	0.29	0.0009	158
Inland waterway – gasoline 4-stroke	152*	0.09	0.004	155
Inland waterway – gasoline 2-stroke	152*	0.24	0.0009	157

* from Table 2, corrected for unburned carbon

† due to rounding to the appropriate number of significant digits, the factor in terms of HHV is numerically equivalent to the factor as provided in IPCC 1997c in terms of LHV

Table 9b. Fuel Consumption-Based Emission Factors [SI units]
for Non-Road Mobile Sources and Machinery (IPCC 1997c)
(IPCC Revised 1996 Guidelines taken from EMEP/CORINAIR)

Source and Engine Type	kg CO ₂ /TJ (HHV)	kg CH ₄ /TJ (HHV)	kg N ₂ O/TJ (HHV)	kg CO ₂ -equiv./TJ (HHV)
Forestry – diesel	69,700*	4†	30†	78,600
Industry – diesel	69,700*	4†	30†	78,600
Railways – diesel	69,700*	4†	30†	78,600
Inland waterway – diesel	69,700*	4†	30†	78,600
Marine – diesel	69,700*	7†	2†	70,400
Industry – gasoline 4-stroke	65,200*	50†	2†	66,800
Forestry – gasoline 2-stroke	65,200*	160	0.4†	68,700
Industry – gasoline 2-stroke	65,200*	120	0.4†	67,900
Inland waterway – gasoline 4-stroke	65,200*	40†	2†	66,600
Inland waterway – gasoline 2-stroke	65,200*	100	0.4†	67,500

* from Table 2, corrected for unburned carbon

† due to rounding to the appropriate number of significant digits, the factor in terms of HHV is numerically equivalent to the factor as provided in IPCC 1997c in terms of LHV

Examples of estimating GHG emissions from vehicles and mobile equipment are presented in Annexes I and J (see calculations I6 and I7, or J6 and J7).

12.0 GREENHOUSE GAS EMISSIONS FROM WASTE IN LANDFILLS

These calculation tools have been developed assuming that many companies will include company-owned landfills within the inventory boundaries. These tools can also be used in cases where a manufacturing plant's process waste is being disposed in a municipal solid waste landfill and the company is interested in estimating the plant's contribution to the municipal landfill emissions. Some companies maintain unmanaged piles of wood residuals. For wood residual piles that are not intentionally composted or otherwise aerated, methane emissions can be estimated using the methods for landfills described in Sections 12.2.1 and 12.2.2.

As is the case with most widely accepted protocols, only CH₄ emissions are addressed in these tools because CO₂ from landfills is composed of biomass carbon and N₂O emissions are assumed to be negligible.

An emission factor for landfilled waste was presented in Table 1. This factor is based on a number of conservative assumptions and, in most cases, is expected to produce estimates that

are higher than the actual emissions attributable to landfilled wood products manufacturing waste. The emission factor can be useful in deciding whether landfill emissions are material to the results of the inventory. The methods described below, however, are recommended for preparing an estimate to use in the inventory results.

12.1 Using Data from Landfill Gas Collection Systems

In some cases, company landfills are capped with low permeability cover material and the landfill gases are collected. In many of these situations, the amounts of methane collected and destroyed can be estimated from site-specific data. IPCC's recommended approach uses this information only indirectly. IPCC recommends that companies estimate landfill gas emissions by first estimating total gas generation (using one of several mathematical models discussed below) and then subtracting the amounts of methane captured and burned. The difference between the two is assumed to be emitted. The problem with this approach is that, because of the large uncertainties in estimating methane generation, the amounts burned could easily be greater than the amounts the company estimates were generated, resulting in a negative release. It is equally possible that the comparison of estimated generation rates to measured collection rates could suggest impossibly low collection efficiencies, due solely to the uncertainties in estimating methane generation.

An alternative approach is available to companies that measure the amounts of methane captured in efficient collection systems: to estimate the collection efficiency of the system and then back calculate the amounts of methane generated. For instance, if a plant with a capped landfill has determined that its collection system collects 90 tons of methane per year and the plant estimates that the collection efficiency is 90%, 100 tons of methane were generated.

The problem with this approach is that the effectiveness of landfill gas collection systems is variable and uncertain. Reported collection efficiencies range from 60 to 85% (USEPA 1998d). This variability and uncertainty has caused IPCC to take the position that "the use of undocumented estimates of landfill gas recovery potential is not appropriate, as such estimates tend to overestimate the amount of recovery" (IPCC 2000a). Nonetheless, this approach is built around a measured value—the amount of gas collected. For this reason, it is reasonable to expect that in some cases, if not many, it will yield more accurate estimates than IPCC's default methodology. This is especially true for wood products plant landfills because of the limited data available for deriving the parameter values needed to use IPCC's mathematical models for estimating emissions.

Therefore, in these calculation tools it is recommended that where company-owned landfills are covered with low permeability caps and equipped with landfill gas collection systems that are constructed and operated to normal standards, the methane generation rates should be back calculated from (a) measurements of the amounts of methane collected; and (b) measured or assumed collection efficiency. A default collection efficiency of 75% has been used by some authorities and is recommended here unless site-specific collection efficiency data are available (USEPA 1998d). These calculation tools also assume that all of the methane that is captured and burned is converted to biomass CO₂ and therefore is not included in GHG totals.

Using these default values and assumptions, estimates of methane releases can be developed using Equation 8.

$$\begin{aligned} CH_4 \text{ (m}^3\text{/y) released to the atmosphere} = \\ [(REC / FRCOLL) * (1 - FRCOLL) * FRMETH * (1 - OX)] + \\ [REC * FRMETH * (1 - FRBURN)] \end{aligned} \quad (\text{Eq. 8})$$

where: *REC* = amount of landfill gas collected, determined on a site-specific basis, m³/y
FRCOLL = fraction of generated landfill gas that is collected, default is 0.75
FRMETH = fraction of methane in landfill gas, default is 0.5
OX = fraction of methane oxidized in the surface layer of the landfill, default is 0.1
FRBURN = fraction of collected methane that is burned, site-specific determination

12.2 Estimating Landfill Methane Emissions at Company-Owned Landfills without Gas Collection Data

12.2.1 Simplified First Order Decay Approach

Where the approach described in Section 12.1 cannot be used, it is recommended that companies employ the first order decay model approach for estimating landfill gas emissions using parameter values derived for wood products plant landfills (suggested values of these parameters are provided in Table 10). This approach is the default method recommended by IPCC and is used by a number of national authorities (IPCC 2000a). It can be used to estimate CH₄ emissions from active and inactive landfills.

In cases where the annual deposits are (or are assumed to be) constant IPCC's default method reduces to two equations. This simplified approach should be adequate unless the amounts or types of waste being landfilled have changed significantly from year to year or the landfill design or operation has been changed in a way that would significantly impact methane generation or release (e.g., a gas collection system is installed). The simplified approach is as follows.

$$CH_4 \text{ (m}^3\text{/y) generated from all waste in the landfill} = R L_0 (e^{-kC} - e^{-kT}) \quad (\text{Eq. 9})$$

where: *R* = average amount of waste sent to landfill per year, Mg/y
*L*₀ = ultimate methane generation potential, m³/Mg waste
k = methane generation rate constant, 1/y
C = time since landfill stopped receiving waste, y
T = years since landfill opened, y
 (Note: *R* and *L*₀ can be in units of wet weight, dry weight, degradable organic carbon, or other units but the units for *R* and *L*₀ must be the same.)

Where companies can separate the quantities of inert wastes (e.g., boiler ash, concrete, etc.) it is recommended that these quantities not be included in the input parameter *R* (average amount of waste sent to the landfill each year).

Not all methane that is generated is subsequently released to the atmosphere. To estimate atmospheric releases, use the result from Equation 9 in Equation 10. For landfills with

modern gas collection and combustion systems but no measurements of quantities of gas collected, the amount of methane recovered can be assumed to be 75% of that generated (USEPA 1998d).

$$CH_4 (m^3/y) \text{ released} = [(CH_4 \text{ generated} - CH_4 \text{ recovered}) * (1 - OX)] + [CH_4 \text{ recovered} * (1 - FRBURN)] \text{ (Eq. 10)}$$

where: $CH_4 \text{ generated}$ = from Equation 9
 $CH_4 \text{ recovered}$ = amount of methane collected, site-specific determination
 OX = fraction oxidized in the surface layer of the landfill before escaping, usually assumed to be 0.1
 $FRBURN$ = fraction of collected methane that is burned, site-specific determination

If the amounts being landfilled have changed significantly or if the landfill design has been altered so that some of the parameter values would have changed substantially over time, a more involved approach may be needed. To deal with these more complicated situations, many protocols recommend modeling the gas generated annually from each year's deposits and summing the amounts that are predicted to occur in the current year. This more detailed analysis is described in Section 12.2.2.

Annex F identifies a number of sources for the parameter values L_0 and k needed in Equation 9. Unfortunately, the values vary considerably from one protocol to the next and are based on very few data. For situations where wood products plant wood residuals and wastewater treatment sludge are major constituents of the waste, reasonable values for the rate constant, k , fall in the range of 0.01/yr to 0.1/yr, while those for L_0 fall between 50 and 200 m^3/Mg . Research is currently underway in the US that should help narrow these ranges. Initial indications are that the amounts of gas generated in wood products landfills are less than would be predicted using parameter values developed for municipal solid waste (NCASI 1999). With this knowledge, it is recommended that until the current research is completed, and unless companies have country-specific or site-specific factors that are more appropriate for their wastes, companies should use the parameter values shown in Table 10. Annex F can be referred to for additional information on the derivation of the default parameters shown in Table 10.

Table 10. Recommended Default Values for k and L_0 for Estimating Wood Products Landfill Methane Emissions

Parameter	Default Value
k	0.03 y^{-1}
L_0	100 m^3/Mg dry weight of waste

12.2.2 Detailed First Order Decay Approach

To allow year-to-year variations in the amounts of waste sent to landfill, IPCC suggests a variation of this approach. Using this variation, starting in year one, calculate how much methane will be generated in each subsequent year by waste deposited in that year using Equations 11 and 12.

$$\begin{aligned} CH_4 \text{ generated in a given year by waste deposited in an earlier year (m}^3\text{/y)} \\ = k R_y L_0 (e^{-k[T-Y]}) \end{aligned} \quad (\text{Eq. 11})$$

where k = methane generation rate constant, 1/yr
 R_y = the amount of waste sent to landfill in year Y , Mg/yr
 L_0 = ultimate methane generation potential, m^3 /Mg waste
 T = year for which emissions are being estimated, given in terms of years since the landfill opened
 Y = year after landfill opened that waste was disposed
Thus $(T-Y)$ is equal to the number of years the waste has been in place prior to the year for which emissions are being estimated.

$$\begin{aligned} CH_4 \text{ (m}^3\text{/y) released} = & [(CH_4 \text{ generated} - CH_4 \text{ recovered}) * (1 - OX)] \\ & + [CH_4 \text{ recovered} * (1 - FRBURN)] \end{aligned} \quad (\text{Eq. 12})$$

where: CH_4 generated = from Equation 10
 CH_4 recovered = amount of methane collected, site-specific determination
 OX = fraction oxidized in the surface layer of the landfill before escaping, usually assumed to be 0.1
 $FRBURN$ = fraction of collected methane that is burned, site-specific determination

Where companies can separate the quantities of inert wastes (e.g., boiler ash, concrete, etc.) it is recommended that these quantities not be included in the input parameter R_y (amount of waste sent to the landfill in year Y).

The calculations are performed by estimating how much waste was deposited every year since the landfill was opened. IPCC indicates that for very old landfills it is possible to limit the retrospective period to one starting at least three waste degradation half-lives before the current year. Given the slow degradation observed in many plant sludges, 25 years is probably the minimum that would satisfy this criterion. For each year's deposit, the amount of methane released that year and each following year is estimated. In subsequent years, the amount of methane released is the sum of the amounts estimated from each prior year's deposits that were projected to occur in that year.

In year 1, amount A is deposited and it is estimated that in years 1, 2, 3, ... it will release X_1 , X_2 , X_3 , ... tons of methane, respectively. The reported emissions for year 1 are X_1 tons of methane. In year 2, amount B is deposited and it is estimated that in years 2, 3, 4, ... it will release Y_2 , Y_3 , Y_4 , ... tons of methane, respectively. The emissions reported for year 2 are X_2 plus Y_2 tons methane. In year 3, amount C is deposited and it is estimated that in years 3, 4, 5, ... it will release Z_3 , Z_4 , Z_5 , ... tons of methane, respectively. The reported emissions for year 3 are X_3 plus Y_3 plus Z_3 tons of methane. This process repeats itself every year.

The values for k and L_0 are the same as those used in the simplified first order approach, as presented in Table 10.

Examples of estimating GHG emissions from landfills are presented in Annexes I and J (see calculations I8 and I9, or J8 and J9).

13.0 GREENHOUSE GAS EMISSIONS FROM ANAEROBIC TREATMENT OF WASTEWATER OR SLUDGE

Most existing GHG protocols address waste treatment plant emissions only from anaerobic treatment and digestion processes. Therefore, these calculation tools have been developed assuming that emissions from other types of wastewater and sludge treatment processes are negligible. Although aerobic and facultative treatment systems may have zones with depleted dissolved oxygen, methane generation rates in aerated stabilization basins, activated sludge systems, and their associated retention ponds would be expected to be much lower than those estimated for anaerobic systems. In any event, due to lack of data, emissions from aerobic and facultative treatment operations are seldom estimated. IPCC, for instance, recommends a default assumption that a methane conversion factor of zero be used for aerobic systems (IPCC 1997c).

Even for anaerobic systems, only CH₄ emissions need to be estimated. The CH₄ emissions from company-owned anaerobic systems will be reported as direct emissions. The CO₂ emitted from wastewater and sludge treatment operations contains biomass carbon which is not included in GHG totals. Where this biomass CO₂ is not combustion related (e.g., it is not formed from combustion of methane), it is often excluded from inventory results altogether. In addition, N₂O emissions from treatment plants have been found to be small, and probably occur only after the wastewater is discharged (IPCC 1997c).

13.1 Anaerobic Treatment Operations where Off-Gases are Captured

In many cases, anaerobic treatment systems are covered and the gases are collected and burned. One of the purposes of these collection systems is the prevention of odors, and to accomplish this objective the systems must be highly efficient. For purposes of a GHG inventory it is reasonable to assume, therefore, that where methane emissions from anaerobic treatment operations are captured and burned, the collection and destruction is complete and no methane is emitted. Because the CO₂ produced in burning the CH₄ contains biomass carbon, it does not need to be reported in GHG inventory totals. If circumstances at a wood products manufacturing plant suggest that non-trivial amounts of methane are escaping collection, the plant may need to undertake efforts to account for these releases, but such circumstances are expected to be unusual at plants that collect and burn these gases.

Of course, if the gases are collected but released to the atmosphere rather than being burned, they should be included in the inventory.

13.2 Anaerobic Treatment Operations where Off-Gases are Released to the Atmosphere

Where off-gases from anaerobic treatment operations are not collected and burned, it is necessary to estimate the releases of methane to the atmosphere. In some cases, for instance where the gases are released through a vent in a covered vessel, the releases can be measured directly. In most other cases, they must be estimated.

These calculation tools suggest the use of the IPCC default methodology described in the May 2000 Good Practices document and shown in Equation 13 (IPCC 2000a). Although the

IPCC document allows the equation to be applied to systems that are not completely anaerobic (by multiplying the result by an arbitrary adjustment factor of less than one), there are no data currently available to support the selection of the adjustment factor. It is recommended, therefore, that methane emissions only be estimated from anaerobic treatment or sludge digestion systems until factors for other types of systems are available.

$$\text{Anaerobic Treatment Plant Methane Emissions (kg/y)} = (OC \times EF) - B \quad (\text{Eq. 13})$$

where: *OC* = BOD or COD of the feed to the anaerobic system, kg/year
EF = emission factor, default values = 0.25 kg CH₄/kg COD in the feed or 0.6 kg CH₄/kg BOD in the feed (or another BOD-based factor developed by multiplying the COD-based factor of 0.25 kg CH₄/kg COD by the site-specific COD/BOD ratio)
B = methane captured and burned, kg CH₄/year, determined on a site-specific basis

If the solids are handled separately, emissions from sludge digestion would be calculated using Equation 14. In cases where sludge is burned, it is included in the calculations for GHG emissions from biomass burning discussed in Section 9.

$$\text{Anaerobic Sludge Digestion Plant Methane Emissions (kg/y)} = (OCs \times EFs) - B \quad (\text{Eq. 14})$$

where: *OCs* = organic content of the sludge
EFs = emission factor, in units consistent with *OCs* - IPCC's default value is 0.25 kg CH₄/kg COD in the sludge feed
B = methane captured and burned, kg CH₄/yr, determined on a site-specific basis

An example of estimating GHG emissions from anaerobic waste treatment systems is presented in Annexes I and J (see calculation I10 or J10).

14.0 PRESENTING THE RESULTS OF THE INVENTORY

These calculation tools provide an example format for summarizing inventory results. Companies may find other formats more convenient or appropriate, however, and are free to choose the format best suited to their needs. It is important that the output from using these calculation tools be (a) disaggregated to the extent possible to ensure transparency; and (b) accompanied by key information needed to interpret the results.

Four tables that companies may use to present the results of the inventory are presented in the following pages. Table 11 provides a format for describing the operations that have been included within the operational inventory boundaries and who owns them. Companies are encouraged to include any additional information that will help explain the boundaries or the results of the inventory.

Table 12 contains an example format that can be used for recording direct emissions. These are emissions within the boundaries of the inventory from sources owned or controlled by the company. The company is free to select a method to determine ownership of emissions from sources only partly owned or controlled by the company, but the method should be described in the presentation of results. Also in this table is an example format for including

information regarding direct emissions which are associated with electricity or steam that is sold to another entity. Companies are encouraged to use this or a similar form to characterize the impact of electricity and steam exports, which can have a significant impact on a facility's greenhouse gas profile

Table 13 is a suggested format for recording indirect emissions (i.e., emissions from sources within the operational boundaries of the inventory but owned by another entity), such as emissions attributable to imports of power and steam and imports and exports of fossil fuel-derived CO₂. Companies are encouraged to use this or a similar form to characterize the impact of outsourced operations (power islands in particular) that have a significant impact on a facility's greenhouse gas profile.

Table 14 provides an example of a format that can be used for recording the emission factors used to prepare the inventory. Companies are encouraged to include this information to make the results of the inventory more transparent.

Tables 15 through 18 illustrate the use of the reporting tables on an example manufacturing plant inventory. The schematic presented in Figure 2 illustrates the various sources and categories of emissions which may be included in an emissions inventory.

Companies wanting to prepare reports that meet the requirements of the WRI/WBCSD GHG Protocol will also need to report releases of CO₂ from biomass combustion separately from direct GHG emissions. Annex G includes a table (Table G1) that can be used for this purpose.

An Excel[®] workbook that performs the calculations described in this report is available. The completed workbook represents yet another way to convey the results of the inventory.

Table 11. Example of a Table to Report Operational Boundaries of the Inventory

This matrix may be used to indicate which operations are included within the boundaries of the inventory and their ownership. Provide a general description of the boundaries, any additional information needed to explain them and then put an "X" in appropriate boxes.

General description of Operational Boundaries:			
Use this space to provide additional information helpful to understanding the operational boundaries of the inventory, including the method used to allocate emissions from partly-owned or partly-controlled sources. <i>Attach additional pages if needed.</i>	Completely Owned by Company	Partly Owned by Company	Owned by other entity
Harvesting			
Wood/chip/bark/ other raw material transportation vehicles			
Product, by-product or waste transportation vehicles			
Debarking			
Chipping			
Mechanical pulping			
On-site power and steam boilers			
On-site combustion turbines			
Lumber kilns			
Furnish dryers (e.g., veneer dryers, rotary dryers, etc.)			
Presses			
Wastewater treatment operations			
Sludge processing			
Landfill receiving plant waste			
Air emissions control devices (e.g., RTOs, RCOs, etc.)			
On-road vehicles			
Off-road vehicles and machinery			
Normal offices/workspace for plant employees			
Other Operation – describe:			
Other Operation – describe:			
Other Operation – describe:			

Table 12. Example of a Table to Report GHG Inventory Results – Direct Emissions
emissions from sources that are wholly or partially owned or controlled by the company

Where emissions have been determined to be insignificant or non-material, write “NM” and explain the basis for the determination in a footnote.		Total Direct Emissions – metric tons			
		CO ₂	CH ₄	N ₂ O	CO ₂ Equiv ¹
	<i>Process and Energy-Related Emissions</i>				
1	Stationary Fossil Fuel Combustion				
2	Biomass Combustion	N/A *			
	<i>Transportation and machinery emissions</i>				
3	On-road vehicles				
4	Off-road vehicles and machinery				
	<i>Waste management emissions</i>				
5	Landfill emissions from plant wastes	N/A *			
6	Anaerobic wastewater treatment systems	N/A *			
7	<i>Other Direct Emissions not included above – Explain:</i>				
	Total Direct Emissions (Sum of lines 1 through 7)				
<i>Emissions associated with exported electricity and steam (a subset of total direct emissions)</i>					
8	Emissions related to electricity exports				
	Carbon intensity of electricity exports (lb CO ₂ /MWh)				
	Carbon intensity of grid receiving electricity exports (lb CO ₂ /MWh)				
	Method used to estimate GHG intensity of grid:				
9	Emissions related to steam exports				
10	Total emissions attributable to exports (Sum of lines 8 and 9)				
Explain the method used to determine ownership/control of sources not completely owned by the company. A protocol such as the WRI/WBCSD GHG Protocol can be used for guidance on determining ownership/control. Include any other information that is needed to understand the inventory results: ¹ CO₂-equivalents are calculated multiplying individual gases by IPCC GWP values, CO₂=1, CH₄=21, N₂O=310, and summing across all three gases. It is acceptable to use emission factors for CO₂-equivalents rather than estimating the three gases individually.					

*N/A – Not Applicable - carbon dioxide emissions from biomass are not included in greenhouse gas totals because this carbon is considered to be part of the natural cycle (i.e., it is recycled between the atmosphere and plant tissue)

Table 13. Example of a Table to Report GHG Inventory Results – Indirect Emissions
emissions attributable to power/steam imports, and imports/exports of fossil-CO₂

Where emissions have been determined to be insignificant or non-material, write “NM” and explain the basis for the determination in a footnote.		Metric tons			
		CO ₂	CH ₄	N ₂ O	CO ₂ Equiv ¹
<i>Indirect emissions related to electricity and steam imports, including those from outsourced power islands</i>					
1	Indirect Emissions related to electricity imports				
2	Indirect Emissions related to steam imports				
3	<i>Total indirect emissions from power/steam imports (Sum of lines 1 through 2)</i>				
<i>Other Indirect Emissions</i>					
4	Description of other indirect emissions included in inventory:				
Explain the method used to determine ownership/control of sources not completely owned by the company. A protocol such as the WRI/WBCSD GHG Protocol can be used for guidance on determining ownership/control. Include any other information needed to understand the inventory results: ¹ CO₂-equivalents are calculated multiplying individual gases by IPCC GWP values, CO₂=1, CH₄=21, N₂O=310, and summing across all three gases. It is acceptable to use emission factors for CO₂-equivalents rather than estimating the three gases individually					

Table 14. Example of a Table to Report Emission Factors (EF) Used to Prepare the Inventory (show units)

		CO ₂	CH ₄	N ₂ O	CO ₂ Equiv	Source of EF
Fossil Fuel Combustion						
Fuel	Combustion Units					
Biomass Combustion						
Fuel	Combustion Units					
		N/A *				
		N/A *				
		N/A *				
		N/A *				
		N/A *				
		N/A *				
		N/A *				
		N/A *				
Waste Management						
Landfill 1 emissions:	% of Gas Collected =		“k”=		“L ₀ ”=	
Landfill 2 emissions:	% of Gas Collected =		“k”=		“L ₀ ”=	
Landfill 3 emissions:	% of Gas Collected =		“k”=		“L ₀ ”=	
Anaerobic Treatment emissions:			“EF”=			
Electrical Power and Steam Imports						
Emissions factors for imported electricity						
Emission factors for imported steam						

*N/A – Not Applicable - carbon dioxide emissions from biomass are not included in greenhouse gas totals because this carbon is considered to be part of the natural cycle (i.e., it is recycled between the atmosphere and plant tissue)

Table 15. Example GHG Inventory Results – Operational Boundaries of the Inventory

This matrix may be used to indicate which operations are included within the boundaries of the inventory and their ownership. Provide a general description of the boundaries, any additional information needed to explain them and then put an “X” in appropriate boxes.

General description of Operational Boundaries:			
Use this space to provide additional information helpful to understanding the operational boundaries of the inventory, including the method used to allocate emissions from partly-owned or partly-controlled sources. <i>Attach additional pages if needed.</i> An on-site gas turbine CHP system owned by another company supplies the plant with power and steam, but much of the power from the system is sold. The emissions are allocated using the simplified efficiency method. When the plant is down, we sometimes continue to generate biomass power in plant-owned condensing turbines and sell it to the grid.	Completely Owned by Company	Partly Owned by Company	Owned by other entity
Harvesting	X		
Wood/chip/bark/other raw material transportation vehicles	X		
Product, by-product or waste transportation vehicles			
Debarking	X		
Chipping	X		
Mechanical pulping			
On-site power and steam boilers	X		
On-site combustion turbines			X
Lumber kilns	X		
Furnish dryers (e.g., veneer dryers, rotary dryers, etc.)	X		
Presses	X		
Wastewater treatment operations	X		
Sludge processing	X		
Landfill receiving plant waste	X		
Air emissions control devices (e.g., RTOs, RCOs, etc.)	X		
On-road vehicles	X		
Off-road vehicles and machinery	X		
Normal offices/workspace for plant employees	X		
Other Operation – describe:			
Other Operation – describe:			
Other Operation – describe:			

Schematic for Example Inventory Results

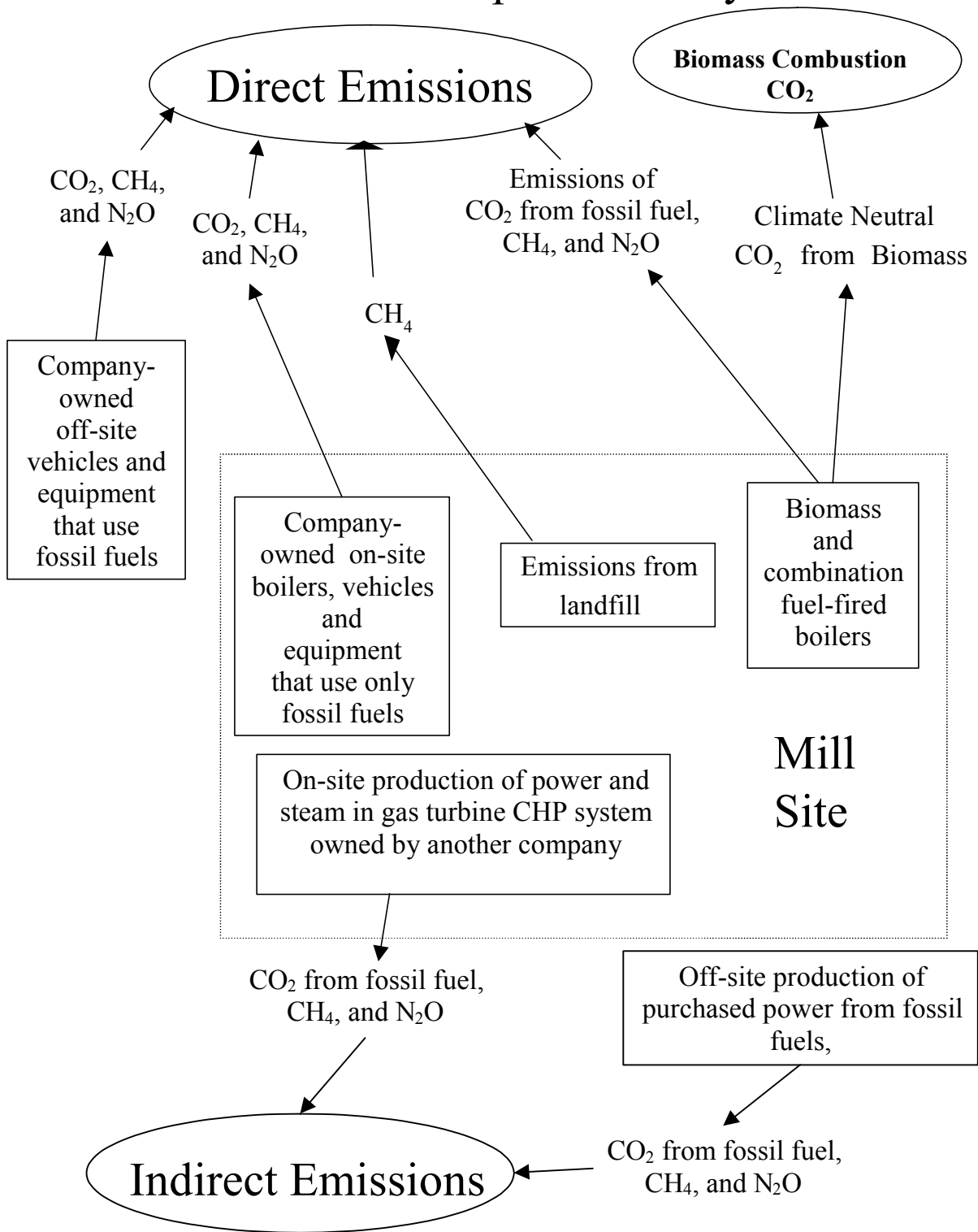


Figure 2. Schematic for Example Inventory Results

Table 16. Example GHG Inventory Results – Direct Emissions
emissions from sources that are wholly or partially owned or controlled by the company

Where emissions have been determined to be insignificant or non-material, write “NM” and explain the basis for the determination in a footnote.		Total Direct Emissions – metric tons			
		CO ₂	CH ₄	N ₂ O	CO ₂ Equiv ¹
	<i>Process and Energy-Related Emissions</i>				
1	Stationary Fossil Fuel Combustion	720000	100	80	746900
2	Biomass Combustion	N/A [*]	120	40	14920
	<i>Transportation and machinery emissions</i>				
3	On-road vehicles	>>>	>>>	>>>	320
4	Off-road vehicles and machinery	NM [†]	NM [†]	NM [†]	NM [†]
	<i>Waste management emissions</i>				
5	Landfill emissions from plant wastes	N/A [*]	511		10730
6	Anaerobic wastewater treatment systems	N/A [*]			NA
7	<i>Other Direct Emissions not included above – Explain:</i>				
	Total Direct Emissions (Sum of lines 1 through 7)	>>>	>>>	>>>	777910
<i>Emissions associated with exported electricity and steam (a subset of total direct emissions)</i>					
8	Emissions related to electricity exports	0	6	2	746
	Carbon intensity of electricity exports (lb CO ₂ /MWh)	<20			
	Carbon intensity of grid receiving electricity exports (lb CO ₂ /MWh)	1452			
	Method used to estimate GHG intensity of grid:				
9	Emissions related to steam exports	0	0	0	0
10	Total emissions attributable to exports (Sum of lines 5 and 6)	0	6	2	746
Explain the method used to determine ownership/control of sources not completely owned by the company. A protocol such as the WRI/WBCSD GHG Protocol can be used for guidance on determining ownership/control. Include any other information that is needed to understand the inventory results: [†] These emissions are uncertain but were estimated using the highest fuel consumption and emission factor data available and were determined to be less than 0.5% of the plant's emissions. They are therefore reported as non-material (NM). ¹ CO₂-equivalents are calculated multiplying individual gases by IPCC GWP values, CO₂=1, CH₄=21, N₂O=310, and summing across all three gases. It is acceptable to use emission factors for CO₂-equivalents rather than estimating the three gases individually.					

*N/A – Not Applicable - carbon dioxide emissions from biomass are not included in greenhouse gas totals because this carbon is considered to be part of the natural cycle (i.e., it is recycled between the atmosphere and plant tissue)

Table 17. Example GHG Inventory Results – Indirect Emissions
emissions attributable to power/steam imports, and imports/exports of fossil-CO₂

Where emissions have been determined to be insignificant or non-material, write “NM” and explain the basis for the determination in a footnote.		Metric tons			
		CO ₂	CH ₄	N ₂ O	CO ₂ Equiv ¹
<i>Indirect emissions related to electricity and steam imports, including those from outsourced power islands</i>					
1	Indirect Emissions related to electricity imports	>>>	>>>	>>>	72000
2	Indirect Emissions related to steam imports	>>>	>>>	>>>	12400
3	<i>Total indirect emissions from power/steam imports (Sum of lines 1 through 2)</i>				84400
<i>Other Indirect Emissions</i>					
4	Description of other indirect emissions included in inventory:				0
Explain the method used to determine ownership/control of sources partly owned by the company. A protocol such as the WRI/WBCSD GHG Protocol can be used for guidance on determining ownership/control. Include any other information needed to understand the inventory results: ¹ CO₂-equivalents are calculated multiplying individual gases by IPCC GWP values, CO₂=1, CH₄=21, N₂O=310, and summing across all three gases. It is acceptable to use emission factors for CO₂-equivalents rather than estimating the three gases individually					

Table 18. Example GHG Inventory Results – Emission Factors (EF) Used to Prepare the Inventory

		CO ₂	CH ₄	N ₂ O	CO ₂ Equiv	Source of EF
Fossil Fuel Combustion						
Fuel	Combustion Units					
Gasoline	forestry equip.				66.8 tonne/TJ HHV	Table 8
Diesel fuel	trucks and machinery				78.6 tonne/TJ HHV	Table 8
Coal	boiler	88.8 tonne/ TJ HHV	0.7 kg/TJ HHV	1.5 kg/TJ HHV		Tables 2 (corrected for unoxidized C) and 5
Natural gas	veneer dryers	50.2 tonne/ TJ HHV	5 kg/TJ HHV	0.1 kg/TJ HHV		Tables 2 (corrected for unoxidized C) and 4
Biomass Combustion						
Fuel	Combustion Units					
bark & wood residual fuels	boiler	N/A*	11 kg/TJ HHV	4 kg/TJ HHV		Table 6
		N/A*				
		N/A*				
		N/A*				
		N/A*				
		N/A*				
		N/A*				
		N/A*				
Waste Management						
Landfill 1 emissions:	% of Gas Collected = 75	“k”= 0.03		“L ₀ ”= 100 m³/Mg dry wt.		
Landfill 2 emissions:	% of Gas Collected =	“k”=		“L ₀ ”=		
Landfill 3 emissions:	% of Gas Collected =	“k”=		“L ₀ ”=		
Anaerobic Treatment emissions:			“EF”=			
Electrical Power and Steam Imports						
Emissions factors for imported electricity						
Power purchased from local grid	>>>	>>>	>>>	726 kg CO ₂ per MWh	Information from power supplier	
Emission factors for imported steam						

*N/A – Not Applicable - carbon dioxide emissions from biomass are not included in greenhouse gas totals because this carbon is considered to be part of the natural cycle (i.e., it is recycled between the atmosphere and plant tissue)

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ANNEX A

GREENHOUSE GAS EMISSIONS FROM STATIONARY FOSSIL FUEL COMBUSTION: OVERVIEW OF METHODS IN EXISTING PROTOCOLS

1.0 IPCC – REVISED 1996 IPCC GUIDELINES FOR NATIONAL GREENHOUSE GAS INVENTORIES AND MAY 2000 GOOD PRACTICES DOCUMENT (IPCC 1997a, 1997b, 1997c, 2000)

The IPCC guidelines are designed for national-level reporting. Therefore, a certain amount of judgment is involved in applying the guidelines at the company or facility level. In the case of energy-related emissions, IPCC has established a three tiered system. Tier 1, which is also part of the Reference Method for national reporting of CO₂ emissions, uses fuel consumption statistics and average emissions factors without regard to the types of combustion technology employed. In the Reference Method, the Tier 1 approach is used to develop national totals by applying it in a “top down” fashion, meaning that national fuel consumption statistics are used. The Tier 1 approach can also be used from the bottom up; i.e., individual facilities can estimate CO₂ emissions from fuel consumption data without considering the type of combustion units being used (IPCC 1997c, pg. 1.7).

IPCC explains that “Tier 2 methods may be regarded as those dividing fuel consumption on the basis of sample or engineering knowledge between technology types which are sufficiently homogenous to permit the use of representative emission factors. Tier 3 methods generally estimate emissions from activity figures (kilometer traveled or tonne-kilometer carried, not fuel consumption) and specific fuel efficiency or fuel rates or, alternatively, using an emission factor or factors expressed directly in terms of a unit of activity” (IPCC 1997c, pg. 1.47).

Simply put, Tier 1 methods use emission factors that vary by fuel type only. The IPCC Reference Method for CO₂ emissions estimates follows a Tier 1 approach. Tier 2 methods use emissions factors that vary by fuel and by type of combustion unit. Tier 2 is the preferred approach for estimating CH₄ and N₂O emissions (however, a Tier 1 approach can be applied to estimating emissions of CH₄ and N₂O), but is not necessary for CO₂ emissions estimates. Tier 3 methods use emission factors that are based on a different measure of activity than fuel consumption (e.g., distance traveled).

1.1 Carbon Dioxide

In general, IPCC recommends using the most accurate and site-specific information available. This suggests that, where possible, IPCC would recommend estimating energy-related CO₂ emissions by multiplying the quantities of fuel consumed by the actual carbon content of the fuel and correcting for unoxidized carbon based on analysis of the ash and emissions. While companies will normally have good records of fuel consumption, it is unlikely that they will have data on the carbon content of all fuels they use. In addition, if data exist on the amounts of unburned carbon in the ash and emissions, they will probably be sparse.

IPCC's Tier 1 approach for estimating CO₂ emissions from fossil fuel combustion uses emission factors that vary by fuel. To reduce the uncertainty caused by using generic information on the carbon contents of fossil fuels, IPCC prefers that the factors be expressed as mass of carbon dioxide per unit of energy (e.g., tons carbon dioxide per terajoule of fossil fuel burned). IPCC explains that "expressing the carbon emissions factor as the carbon content per unit of energy released reduces [the] variation because of the close link between the carbon content and energy value of the fuel." In this report, unless shown otherwise, fossil fuel energy content is always expressed as the net calorific value (NCV) of the fuel, also known as the lower heating value (LHV).

Once the consumption statistics have been converted to units of energy, they must be multiplied by the corresponding carbon emission factor for each fossil fuel. If a company has site-specific data on the carbon content of the fossil fuels being burned, these data are preferred. If such data are not available, IPCC accepts the use of generic carbon dioxide emission factors. The default carbon dioxide emission factors for the IPCC reference method are shown in Table 1-2 of the IPCC Guidelines Workbook. The emission factors for fuels most likely to be of interest to wood products plants are shown in Table A1.

Table A1. IPCC Default Emission Factors for Fossil Fuels (after IPCC 1997b);
[converted from IPCC's factors, which are expressed
in units of carbon rather than carbon dioxide]

Fossil Fuel	kg CO ₂ /TJ*
Crude oil	73,300
Gasoline	69,300
Kerosene	71,900
Diesel oil	74,100
Residual fuel oil	77,400
LPG	63,100
Petroleum coke	100,800
Anthracite coal	98,300
Bituminous coal	94,600
Sub-bituminous coal	96,100
Lignite	101,200
Peat	106,000
Natural gas	56,100

* assuming no unburned carbon

The IPCC Reference Manual also shows several equations that can be used to estimate the carbon dioxide emission factors for natural gas and certain coals (IPCC 1997c).

For natural gas, IPCC presents a relationship wherein the carbon emission factor is shown as a function of the gross calorific value (H_V) or high heating value of the natural gas as shown in Equation A1.

$$\begin{aligned} \text{Tons Carbon /TJ} &= 13.708 + (0.0828 \times 10^{-3}) \times (H_V \text{ in kJ/m}^3 - 37.234) \\ \text{Tons CO}_2 \text{ /TJ} &= \text{Tons Carbon/TJ} \times 44/12 \end{aligned} \quad (\text{Eq. A1})$$

The 1996 IPCC Reference Manual also shows a relationship for estimating the carbon emission factors for coals with gross calorific values (H_V) between 31 and 37 terajoules per kiloton on a dry mineral matter free (dmf) basis (IPCC 1997c).

$$\begin{aligned} \text{Tons Carbon /TJ} &= 32.15 - (0.234 \times H_V \text{ in TJ/kiloton, dry mineral free basis}) \\ \text{Tons CO}_2 \text{ /TJ} &= \text{Tons Carbon/TJ} \times 44/12 \end{aligned} \quad (\text{Eq. A2})$$

After multiplying the amount of fuel burned (in units of energy) by the appropriate emission factor (in units of ton carbon or tons CO₂ per unit of energy), IPCC corrects the resulting emission estimate to account for unoxidized carbon in the ash and emissions. IPCC acknowledges that the amount of unoxidized carbon is highly variable between fuels and combustion units. None-the-less, IPCC recommends default correction factors of 0.98 for coal, 0.99 for oil, and 0.995 for gas to correct CO₂ emissions estimates for unburned carbon (IPCC 1997c).

Where coal is burned one could estimate unoxidized carbon based on the carbon content of the ash. IPCC acknowledges that for coal-fired boilers most of the unoxidized carbon is in the ash. This approach would not work, however, for units burning a combination of fossil fuels and biomass fuels, such as those that burn coal (or other fossil fuels) in combination with bark or wood residual fuels. In these cases, it will probably not be possible to differentiate between unoxidized carbon of fossil fuel origin and unoxidized carbon from the biomass.

IPCC discusses several studies that provide more resolution than the IPCC Tier 1 default factors for unoxidized carbon. The IPCC Reference Manual lists several sources of data to support Tier 2 approaches to estimating unoxidized carbon (although these data are included in the Tier 1 section of the manual). An Australian study is cited which shows the unoxidized carbon from stoker-fired boilers ranging from 1 to 12% for coals with ash contents of 8 to 23%. A value of 2% is suggested as best practice, 5% for average practice, and 10% for worst practice (IPCC 1997c).

A similar study by British Coal produced the following data that can be used to develop Tier 2 estimates of unburned carbon as a function of combustion technology (IPCC 1997c).

Pulverized coal	1.6%
Traveling grate stoker	2.7 to 5.4%
Underfeed stoker	4.0 to 6.6%
Shallow bed advanced fluidized bed boiler	up to 4.0%
Pressurized or circulating fluidized bed combustion	3.0%

Finally, the IPCC Reference Manual indicates that well maintained natural gas fired boilers often attain combustion efficiencies of 99.9%, suggesting that for most gas-fired industrial boilers, the default value for unoxidized carbon (0.5%) may be too large (IPCC 1997c).

1.2 Methane

IPCC offers Tier 1 and Tier 2 approaches for estimating methane emissions from stationary fossil fuel combustion.

For the energy industries, the Tier 1 methane emission factors are 1 kg/TJ for coal and natural gas, and 3 kg/TJ for oil. For the manufacturing industries and construction, methane emissions factors are 10 kg/TJ for coal, 5 kg/TJ for natural gas, and 2 kg/TJ for oil (IPCC 1997c, pg. 1.35).

The Tier 2 factors are presented in two pieces—an uncontrolled emission factor coupled with a factor to reflect the effectiveness of various emission control devices. The uncontrolled emission factors are different for utility and industrial boilers. The uncontrolled methane emission factors for industrial boilers are shown in Table 1-16 of the IPCC Reference Manual, and Table 1-17 lists methane emission factors for several industrial processes involving fossil fuel combustion, including dryers. Those tables are reproduced as Tables A2 and A3 herein. They also contain the emission factors for nitrous oxide, discussed in more detail in Section 1.3. The industrial boiler and dryer emission controls performance for methane is listed in the Reference Manual (Tables 1-21 and 1-22) as being negligible, so the uncontrolled emissions in Tables 1-16 and 1-17 can be considered equal to final controlled emissions (IPCC 1997c).

Table A2. IPCC Industrial Boiler Uncontrolled Emission Factors
(IPCC 1997c, Table 1-16)

Fuel and Equipment Type	kg CH ₄ /TJ	kg N ₂ O/TJ
Coal		
Bit./Sub-bit. Overfeed Stoker Boilers	1	1.6
Bit./Sub-bit. Underfeed Stoker Boilers	14	1.6
Bit./Sub-bit. Hand-fed Units	87	1.6
Bituminous/Sub-bituminous Pulverized Dry Bottom, wall Fired	0.7	1.6
Bituminous/Sub-bituminous Dry Bottom, tangentially fired	0.7	0.5
Bituminous/Sub-bituminous Wet Bottom	0.9	1.6
Bituminous Spreader Stokers	1	1.6
Bit./Sub-bit. Fluidized Bed Combustor Circulating Bed	1	96
Bit./Sub-bit. Fluidized Bed Combustor Bubbling Bed	1	96
Anthracite Stokers	NAV	NAV
Anthracite Fluidized Bed Combustor Boilers	NAV	NAV
Anthracite Pulverized Coal Boilers	NAV	NAV
Oil		
Residual Fuel Oil Boilers	3	0.3
Distillate Fuel Oil Boilers	0.2	0.4
LPG Boilers Propane	NAV	NAV
LPG Boilers Butane	NAV	NAV
Small Stationary Internal Comb. Engines Gasoline <250 hp (186 kW)	NAV	NAV
Small Stationary Internal Comb. Engines Diesel <600 hp (447 kW)	NAV	NAV
Large Stationary Diesel Engines >600 hp (447 kW)	0	NAV
Natural Gas		
Large Boilers >100 MBtu/h (293 MW)	1.4	NAV
Small Boilers 10-100 MBtu/h (29.3-293 MW)	1.4	NAV
Heavy Duty Nat. Gas. Compressor Eng. – Turbines	0.6	NAV
Heavy Duty Nat. Gas. Compressor Eng. – 2-Cycle Lean Burn	17	NAV
Heavy Duty Nat. Gas. Compressor Eng. – 4-Cycle Lean Burn	13	NAV
Heavy Duty Nat. Gas. Compressor Eng. – 4-Cycle Rich Burn	2.9	NAV

Note: NAV means Not Available

Table A3. IPCC Uncontrolled Emission Factors for Dryers
(IPCC 1997c, Table 1-17)

Fuel	kg CH ₄ /TJ fuel	kg N ₂ O/TJ fuel
Natural gas	1.1	No Data
Oil	1.0	No Data
Coal	1.0	No Data

1.3 Nitrous Oxide

IPCC's approach to estimating nitrous oxide emissions is the same as it uses for methane. IPCC offers both Tier 1 and Tier 2 approaches. For both the "energy industries" and "manufacturing industries and construction," the Tier 1 emission factors are 1.4 kg nitrous oxide/TJ for coal, 0.1 kg/TJ for natural gas, and 0.6 kg/TJ for oil (IPCC 1997c, pg. 1.36).

The Tier two factors are presented in two pieces—an uncontrolled emission factor coupled with a factor to reflect the effectiveness of various emission control devices. The uncontrolled emissions factors are different for utility and industrial boilers. The uncontrolled nitrous oxide emission factors for industrial boilers are shown in Table 1-16 of the IPCC Reference Manual reproduced below. The Tier 2 approach involves correcting uncontrolled emissions to account for the impact of control technologies. The only case where IPCC provides the needed data, however, is in the case of selective catalytic reduction applied to gas fired boilers. IPCC indicates that SCR accomplishes a 60% reduction in uncontrolled nitrous oxide emissions from gas fired boilers. In all other cases, the uncontrolled emissions must be used because there are no data supplied on control technology effectiveness (shown as "not available" in Tables 1-21 and 1-22 of the Reference Manual) (IPCC 1997c).

2.0 CANADA – GUIDE TO ENTITY- AND FACILITY-BASED REPORTING, CANADA'S CLIMATE CHANGE VOLUNTARY CHALLENGE AND REGISTRY (VCR 2003)

2.1 Carbon Dioxide

The Voluntary Challenge and Registry (VCR) Guidelines are intended to facilitate participation in Canada's Voluntary Challenge and Registry Program. The VCR guidelines include recommendations for estimating CO₂ emissions from stationary fossil fuel combustion which are generally comparable to IPCC's Tier 1 sectoral approach. The emission factors most appropriate for industrial users, extracted from the table of emission factors which are published in Section 9 of the VCR Guidelines, are shown in Tables A4 and A5 (for coal fuels) (VCR 2003), and are listed by region and by type of coal burned. The emission factors published by VCR are mainly derived from those used to develop Canada's GHG inventory (Environment Canada 2002), and are normalized to the volume or weight of fuel rather than heat content. No correction factor is applied for unoxidized carbon, this having apparently been incorporated into the emission factors.

The VCR program is being modified to reflect the implications of the Canadian government's ratification of the Kyoto Protocol. Therefore, it is recommended that users

interested in the VCR guidance check for the most current version (available for download from the VCR website).

Table A4. Canadian Emission Factors for Stationary Combustion
(reproduced from Table 3 of VCR 2003)

Fuel	CO ₂	CH ₄	N ₂ O
Natural gas	1.891 kg/m ³	0.000037 kg/m ³	0.000033 kg/m ³
Light (distillate) oil	2.830 kg/l	0.000006 kg/l	0.000031 kg/l
Heavy (residual) oil	3.090 kg/l	0.00012 kg/l	0.000064 kg/l
Kerosene	2.550 kg/l	0.000006 kg/l	0.000031 kg/l
Propane	1.500 kg/l	0.000024 kg/l	0.000108 kg/l
Diesel motors (stationary)	2.730 kg/l	0.00013 kg/l	0.0004 kg/l

Table A5. Canadian Emission Factors for Coal Fired Boilers
(reproduced from Table 12 of VCR 2003)

Region	Coal Type	CO ₂ (kg/kg) (1990-1994)	CO ₂ (kg/kg) (1995-1999)	CH ₄ (kg/kg)	N ₂ O (kg/kg)
Nova Scotia	Can. bituminous	2.300	2.249	0.00003	0.00002
	US bituminous	2.330	2.288		
New Brunswick	Can. bituminous	2.230	1.996		
	US bituminous	2.500	2.311		
Quebec	US bituminous	2.500	2.343		
	Anthracite	2.390	2.390		
Ontario	Can. bituminous	2.520	2.254		
	US bituminous	2.500	2.432		
	Sub-bituminous	2.520	1.733		
	Lignite	1.490	1.476		
	Anthracite	2.390	2.390		
Manitoba	Can. bituminous	2.520	2.252		
	Sub-bituminous	2.520	1.733		
	Lignite	1.520	1.424		
Saskatchewan	Lignite	1.340	1.427		
Alberta	Can. bituminous	1.700	1.852		
	Sub bituminous	1.740	1.765		
	Anthracite	2.390	2.390		
British Columbia	Can. bituminous	1.700	2.072		
All provinces	Metallurgical coke	2.480	2.480		

2.2 Methane

Methods for estimating methane emissions from fossil fuel combustion are comparable to IPCC's Tier 1 methods except that (a) the emission factors are mass- or volume-based rather

then energy-based, and (b) there is no discussion of a correction for the effectiveness of control devices (an unimportant difference, as IPCC assumes 0% removal of methane).

2.3 Nitrous Oxide

Like methane, methods for estimating N₂O emissions from fossil fuel combustion are comparable to IPCC's Tier 1 methods except that (a) the emission factors are mass- or volume-based rather than energy-based, and (b) there is no discussion of a correction for the effectiveness of control devices (an unimportant difference, as IPCC provides removal data only for gas-fired boilers equipped with selective catalytic reduction).

3.0 UNITED STATES – INVENTORY OF US GREENHOUSE GAS EMISSIONS AND SINKS: 1990-1999 (USEPA 2001a)

3.1 Carbon Dioxide

The methods used by USEPA to develop its annual inventory for CO₂ from stationary fossil fuel combustion are similar to the IPCC Tier 1 methods. One difference is that the US fossil fuel consumption statistics are shown in GCV rather than NCV (the EPA report indicates that NCV is used for certain biomass fuels).

Another departure from the IPCC Tier 1 approach is in the matter of the unoxidized carbon in coal burning—USEPA uses 1% rather than the 2% default value suggested by IPCC.

The carbon factors and correction factors for unoxidized carbon are contained in Table A-13 in Annex A of the EPA report. The emission factors from that table are shown in Table A6 herein. Although the report is not explicit, it can be assumed that the carbon factors are based on gross calorific values (USEPA 2001a).

Table A6. USEPA CO₂ Emission Factors for Fossil Fuels
(from Table A-13 from Annex A of USEPA 2001a)
[heat content in Gross Calorific Value]

Fuel Type	Tg C/QBtu HHV	Tg CO ₂ /QBtu HHV
Industrial other coal*	25.63	93.98
Coke imports	27.85	102.12
Utility coal*	25.76	94.45
Natural gas	14.47	53.06
Distillate fuel oil	19.95	73.15
Kerosene	19.72	72.31
LPG*	16.99	62.30
LPG (energy use)*	17.11	62.74
LPG (non-energy use)*	16.88	61.89
Motor gasoline*	19.36	70.99
Residual fuel	21.49	78.80

* EPA indicates that these vary from year to year; values shown are for 1999

3.2 Methane

EPA used IPCC's Tier 1 default methodology and emission factors to estimate methane emissions from fossil fuel combustion in steam and power production (USEPA 2001a).

3.3 Nitrous Oxide

EPA used IPCC's Tier 1 default methodology and emission factors to estimate nitrous oxide emissions from fossil fuel combustion in steam and power production (USEPA 2001a).

4.0 WRI/WBCSD – THE GREENHOUSE GAS PROTOCOL AND SUPPORTING GUIDANCE (WRI 2001a [replaced by WRI 2004a], 2004b, 2004c)

4.1 Carbon Dioxide

WRI/WBCSD recommends that site-specific information on fuel use and fuel carbon content (if available) be used to estimate CO₂ emissions from stationary combustion sources. If site-specific data on fuel carbon content are unavailable, the WRI/WBCSD guidance material contains a large number of emission factors from other sources. Some of the ones of potential interest to wood products plants are shown in Table A7. The guidance indicates that WRI/WBCSD protocol encourages using a correction for unoxidized carbon, and notes that this may be especially important for small coal-fired units (WRI 2004b, 2004c).

4.2 Methane and Nitrous Oxide

The WRI/WBCSD guidance does not include CH₄ and N₂O. The October 2001 guidance states, “a much greater effort is required to estimate CH₄ and N₂O emissions from stationary sources [compared to CO₂], and a much higher level of uncertainty exists. Consequently, due the relative insignificance of CH₄ and N₂O emissions from most stationary sources, [the WRI/WBCSD protocol] only includes guidance for estimating CO₂ emissions from stationary sources” (WRI 2001b).

Table A7. WRI/WBCSD CO₂ Emission Factors for Stationary Combustion, October 2001 (WRI 2001c)

[illegible]

ANNEX B

METHANE AND NITROUS OXIDE EMISSIONS FROM BIOMASS COMBUSTION: OVERVIEW OF METHODS IN EXISTING PROTOCOLS

1.0 IPCC – REVISED 1996 IPCC GUIDELINES FOR NATIONAL GREENHOUSE GAS INVENTORIES AND MAY 2000 GOOD PRACTICES DOCUMENT (IPCC 1997a, 1997b, 1997c, 2000)

1.1 Methane

IPCC offers Tier 1 and Tier 2 approaches for estimating methane emissions from biomass combustion. For the energy industries and the manufacturing industries and construction, the Tier 1 methane emission factor is 30 kg CH₄/TJ for wood, wood residual fuels, and other biomass and residuals (IPCC 1997c).

The Tier two factors are presented in two pieces—an uncontrolled emission factor coupled with a factor to reflect the effectiveness of various emission control devices. The only methane emission factors for biomass, however, are for industrial boilers. Table 1-16 of the IPCC Reference Manual describes emission factors for four types of wood burning, fuel cell/Dutch oven boilers, stoker boilers, FBC boilers, and bagasse/agricultural waste boilers. The only one of these with a corresponding methane emission factor is stoker boilers, where the emission factor is 15 kg CH₄/TJ. The methane removal accomplished by industrial boiler emission controls is listed in the IPCC Reference Manual (Table 1-21) as negligible, so the uncontrolled emissions are the same as final controlled emissions (IPCC 1997c).

For both Tiers 1 and 2, IPCC appears to have relied, at least in part, on the 1995 EPA AP-42 document, but the methane and nitrous oxide factors for biomass have changed in more recent versions of AP-42 (see the discussion of the US protocol in Section 3 for the most recent AP-42 emission factors).

1.2 Nitrous Oxide

IPCC's approach to estimating nitrous oxide emissions is the same as it uses for methane. IPCC offers both Tier 1 and Tier 2 approaches, but includes emission factors only for Tier 1. For the energy industries and the manufacturing industries and construction, the Tier 1 nitrous oxide emission factor is 4 kg N₂O/TJ for wood, wood residuals, and other biomass and wastes (IPCC 1997c).

Table 1-16 of the IPCC Reference Manual, which contains Tier 2 emission factors, discusses emission factors for four types of wood burning, fuel cell/Dutch oven boilers, stoker boilers, FBC boilers, and bagasse/agricultural waste boilers, but there are no factors in the table for N₂O (IPCC 1997c).

For both Tiers 1 and 2, IPCC appears to have relied, at least in part, on the 1995 EPA AP-42 document, but the methane and nitrous oxide factors for biomass have changed in more recent versions of AP-42 (see the discussion of the US protocol in Section 9 for the most recent AP-42 emission factors).

2.0 CANADA – GUIDE TO ENTITY- AND FACILITY-BASED REPORTING, CANADA’S CLIMATE CHANGE VOLUNTARY CHALLENGE AND REGISTRY (VCR 2003)

2.1 Methane

The recommended method for estimating GHG emissions from biomass fuel combustion is generally comparable to IPCC’s Tier 1 sectoral approach except that VCR recommended biomass emission factors are based on mass of fuel rather than heat content. The emission factors are published in Section 9 of the VCR Guidelines, and are derived mainly from those used to develop Canada’s GHG inventory (Environment Canada 2002). The emission factor for methane from wood fuel/wood residual fuels is 0.05 g CH₄/kg fuel (VCR 2003). This factor is significantly lower than the IPCC Tier 1 emission factor for wood and wood residuals. The emission factor for methane from spent pulping liquors is also 0.05 g CH₄/kg fuel (VCR 2003). It is assumed that the emission factor for pulping liquors is based on the weight of solids in the liquor, rather than the total liquor mass.

In *Canada’s Greenhouse Gas Inventory, 1990-2000* (Environment Canada 2002), Appendix D explains that the emission factors for biomass fuels were derived from those available in EPA’s AP-42. The AP-42 factors have since changed (see the discussion of the US protocol in Section 9 for the most recent AP-42 emission factors). Although the guidelines do not indicate whether the factors are based on wet or dry weight of fuel, the emission factor shown for CO₂ from wood fuel/wood residual fuels suggests that the factors are based on wet weight. Informal communication with Environment Canada staff confirm that the CO₂ emission factor for wood/wood residuals is based on wet weight of wood at 50% moisture, with a higher heating value of 4500 Btu/lb. During these informal discussions it was revealed that there may be some errors with the methane and nitrous oxide emission factors for wood/wood residuals published by Environment Canada (Environment Canada 2002), which in turn are the cited sources for the emission factors in the VCR guidance. Environment Canada has indicated that it will revise these factors sometime in 2003.

There is no discussion of the effectiveness of control devices, but it is assumed that the factors are for emissions after control devices. This is an unimportant departure from IPCC methods, as IPCC assumes that there is no removal of methane across control devices.

2.2 Nitrous Oxide

As with methane, the VCR recommended methods for estimating N₂O emissions from biomass fuel combustion are comparable to IPCC’s Tier 1 methods except that (a) the emission factors are mass- or volume-based rather than energy-based, and (b) there is no discussion of a correction for the effectiveness of control devices (an unimportant difference, as IPCC provides removal data only for gas-fired boilers equipped with selective catalytic reduction). The emission factor for nitrous oxide from wood fuel/wood residual fuels is 0.02 g N₂O/kg fuel, and is derived from factors used to develop Canada’s GHG inventory (Environment Canada 2002). This emission factor is significantly lower than the IPCC Tier 1 emission factor. It is assumed that this factor estimates emissions based on wet weight of fuel and after control devices. The emission factor for nitrous oxide from combustion of

spent pulping liquors is also 0.02 g N₂O/kg fuel (VCR 2003). It is assumed that this factor is based on the weight of dry solids in the pulping liquor, rather than the total liquor mass.

In *Canada's Greenhouse Gas Inventory, 1990-2000* (Environment Canada 2002), Appendix D explains that the emission factors were derived from those available in EPA's AP-42, which have since changed (see the discussion of the US protocol in Section 3 for the most recent AP-42 emission factors). However, as discussed in Section 2.1, informal discussions with Environment Canada staff have indicated that there may be errors in the recommended nitrous oxide emission factor for wood/wood residuals combustion. Environment Canada has indicated that these factors may be modified sometime in 2003.

3.0 UNITED STATES – INVENTORY OF US GREENHOUSE GAS EMISSIONS AND SINKS: 1990-1999 (USEPA 2001a) AND AP-42 EMISSIONS FACTORS (USEPA 2001b)

3.1 Methane

In its GHG inventory, EPA used IPCC's Tier 1 default methodology and emission factors to estimate methane emissions from biomass fuels. The only emission factor is for wood—30 kg CH₄/TJ (USEPA 2001a).

USEPA's AP-42 Emission Factors Document (Supplement G, July 2001) indicates that “[m]ethane emissions are highest during periods of low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycle for boilers. Typically, conditions that favor formation of N₂O also favor emissions of CH₄” (USEPA 2001b). The emission factor given in Supplement G as the average emission factor for methane from wood residue combustion is 0.021 lb/MMBtu GCV (9.5 kg CH₄/TJ NCV assuming that NCV is 5% less than GCV).

3.2 Nitrous Oxide

In its GHG inventory, EPA used IPCC's Tier 1 default methodology and emission factors to estimate nitrous oxide emissions from biomass fuels. The only emission factor is for wood—4 kg N₂O/ TJ (USEPA 2001a).

USEPA's AP-42 Emission Factors Document (Supplement G, July 2001) indicates that “[f]ormation of N₂O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N₂O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent)” (USEPA 2001b). In earlier supplements to AP-42, EPA had given separate emission factors for stoker boilers and fluidized boilers based on a theory that fluidized bed boilers generated more N₂O. In the current supplement, this distinction has been eliminated and a single N₂O emission factor is shown for all wood-fired boilers. The emission factor given in Supplement G as the average emission factor for nitrous oxide from wood residue combustion is 0.013 lb/MMBtu GCV (5.9kg N₂O/TJ NCV assuming that NCV is 5% less than GCV).

4.0 WRI/WBCSD – THE GREENHOUSE GAS PROTOCOL AND SUPPORTING GUIDANCE (WRI 2001a [replaced by WRI 2004], 2001b, 2001c)

4.1 Methane and Nitrous Oxide

The WRI/WBCSD guidance does not include CH₄ and N₂O. The October 2001 guidance states, “a much greater effort is required to estimate CH₄ and N₂O emissions from stationary sources [compared to CO₂], and a much higher level of uncertainty exists. Consequently, due the relative insignificance of CH₄ and N₂O emissions from most stationary sources, [the WRI/WBCSD protocol] only includes guidance for estimating CO₂ emissions from stationary sources” (WRI 2001b).

5.0 OTHER DATA ON NON-CO₂ GHG EMISSIONS FROM BIOMASS COMBUSTION

In reviewing the emission factors most commonly used for methane and nitrous oxide from biomass combustion, most are based on very sparse data. In several cases, protocols suggest using factors from USEPA that are no longer supported by that agency.

Fortunately, in the last few years additional data have been generated that, while not widely known, provide an improved basis for estimating these emissions.

5.1 Finnish Data from Fortum Power and Heat Oy (Fortum 2001)

Perhaps the most ambitious recent study was undertaken in Finland by Fortum Power and Heat Oy with funding from the Finnish Forest Industries Federation and the Finnish Energy Industries Federation. The report, *Methane and Nitrous Oxide Emissions in the Finnish Energy Production*, was published in May 2001 and contains new data from eleven boilers and two pulp mill recovery furnaces (Fortum 2001). Of the eleven boilers, six were fluidized bed boilers burning biomass and/or peat, two were pulverized coal-fired boilers, two were combined cycle gas turbine facilities, and one was a heavy oil boiler. In addition, the report summarizes existing emission factors, noting that most of them had been proven to be unreliable.

The results of the study are summarized and contrasted to earlier emission factors in a Table B1. The authors concluded that “fixed emission factors do not work well in CFB boilers. The emission factor has to be such that it considers both the boiler load and fuel” (Fortum 2001).

Table B1. Comparison of Measured N₂O and CH₄ Emissions with Other Emission Factors
(Table 14 from Fortum Power and Heat Oy 2001)

		CFB-boilers	BFB-boilers	PC-boilers	Gas turbine plants	Recovery boilers	Heavy oil boiler
N ₂ O national factor	mg/MJ	30 - 39	27 - 30	2	1	1.4	2
N ₂ O IPCC- factor	mg/MJ	4	4	1.4	0.1	4	0.6
N ₂ O measured	mg/MJ	<2...26	<2	<1	<3	<1	<1
CH ₄ national factor	mg/MJ	11.1 - 22.4	14.5 - 21.3	4	3	1	8
CH ₄ IPCC- factor	mg/MJ	30	30	1	1	30	3
CH ₄ measured	mg/MJ	1	1 - 3 (72)	<1	<1 (26)	1	<1

parentheses indicate abnormal process conditions

Using data from the Fortum report, NCASI has estimated that the median emission factors for circulating fluidized bed boilers burning peat or bark were 1 kg CH₄/TJ and 8.8 kg N₂O/TJ. The median emission factors for bubbling fluidized bed boilers burning peat or bark were 2 kg CH₄/TJ (excluding one very large number associated with low oxygen, high carbon monoxide conditions) and <2 kg N₂O/TJ.

5.2 US Data from NCASI

Although not as recent or extensive, NCASI developed methane data in the late 1970s and early 1980s (NCASI 1980, 1985). The results are shown in Table B2. The methane emissions fall within the range of the newer Finnish data, but tend to be a little higher, on average. This is perhaps not surprising, as the NCASI data were generated on older technology boilers during a period when there was not as much emphasis on combustion control. Still, the data are fairly consistent and, in any event, far lower than IPCC's default value.

Table B2. Data on Methane Emissions from Wood Residue Boilers
Collected in the Late 1970s and Early 1980s, Generated by EPA Method 25
[data have been converted from GCV to NCV assuming a 5% difference]

Reference	Boiler Types	Number of Boilers	Methane Emissions mg/MJ NCV		
			Min.	Max.	Ave.
NCASI Air Technical Bulletin 109 (NCASI 1980)	1952 to 1976 vintage, stoker-fed boilers, sampled before particulate control devices	4	<1	20.4	8.2
NCASI Technical Bulletin 455 (NCASI 1985)	1952 to 1981 vintage, stoker-fed boilers, all but one sampled after wet scrubbers	6	<1	4.5	2.7

ANNEX C

GREENHOUSE GAS EMISSIONS ATTRIBUTABLE TO IMPORTS AND EXPORTS OF POWER AND STEAM: OVERVIEW OF METHODS IN EXISTING PROTOCOLS

1.0 IPCC – REVISED 1996 IPCC GUIDELINES FOR NATIONAL GREENHOUSE GAS INVENTORIES AND MAY 2000 GOOD PRACTICES DOCUMENT (IPCC 1997a, 1997b, 1997c, 2000)

Because the IPCC guidelines are for national inventories, they have very little guidance on how to apportion emissions related to facility-level imports and exports of power. The most relevant discussion regards methods for developing sectoral-level emissions estimates. The discussion herein is based on the 1996 Revised IPCC Guidelines for sectoral-level reporting.

In Volume 1 – Reporting Instructions for IPCC’s Revised 1996 guidance, Chapter 1 describes the general method used by IPCC to assign emissions to various sectors (IPCC 1997a). Energy-related emissions from the solid wood products industry are included in the Other subcategory (category 1.A.2.f) in the Manufacturing Industries and Construction (category 1.A.2) portion of the reporting framework. The guidance explains that this part of the framework is to include “[e]missions from combustion of fuels in industry including combustion for the generation of electricity and heat. Emissions from autoproductors [companies that produce their own electrical power] should be assigned to the sector where they were generated and an attempt made to separately identify the emissions associated with autogeneration from those associated with process heat” (IPCC 1997a, page 1.4).

Autoproductors are defined as “undertakings which generate electricity/heat wholly or partly for their own use, as an activity which supports their primary activity.” In Volume 3 of the Reference Manual, there is additional elaboration in Box 3 on page 1.32 (IPCC 1997a): “An autoproducer of electricity or heat is an enterprise which generates electricity or sells heat as a secondary activity, i.e., not as its main business. This should be contrasted with the main power producers who generate electricity or who sell heat as their main business (primary activity) and may be publicly or privately owned. Supplies from main power producers are referred to as ‘Public’ electricity and heat supply although an increasing part of public supply is being met by autoproductors” (IPCC 1997a).

The section on generation of electricity and heat in the Reference Manual indicates that “emissions from autoproduction are attributed to the industrial or commercial branches in which the generation activity occurs. Emissions reported under ‘Public Electricity and Heat’ should be those from main power producers only” (IPCC 1997c, pp 1.31 and 1.32).

Thus, it is clear that IPCC’s method places all energy-related emissions from wood product plants in the manufacturing sector unless the emissions are from an activity where wood products manufacture is not the primary business. The emissions from boilers making steam, some of which is exported or used to make exported electricity, remain in the manufacturing sector unless the boilers are associated with a separate business that just happens to be located on the plant site. Similarly, the emissions from gas turbines on plant sites are

attributed to the manufacturing sector unless, perhaps, the turbines are owned by a separate company whose main business is power generation.

Likewise, emissions from the off-site production of electricity used by wood product plants remain in the energy sector rather than being assigned to the manufacturing sector.

It is clear from all this that IPCC's objective is to eliminate double counting in national inventories by providing guidance as to how energy-related emissions should be reported. IPCC's general intention is that emissions be reported in the sector where they were generated and IPCC puts a facility, and all of its emissions, into the sector representing its primary activity.

2.0 CANADA – GUIDE TO ENTITY- AND FACILITY-BASED REPORTING, CANADA'S CLIMATE CHANGE VOLUNTARY CHALLENGE AND REGISTRY (VCR 2003)

The VCR guidance recommends that companies “report both direct and indirect emissions separately where possible. While your organization does not bear full responsibility for indirect emissions (such as those from purchased electricity), it is useful to track these emissions as part of your organization's overall GHG profile” (VCR 2003). Emission factors are supplied to convert purchased electricity into CO₂ emissions. The factors vary by province and year, reflecting the methods and fuels used to generate electricity. The factors for year 2001 are shown in Table C1 (VCR 2003). The VCR program is currently being modified to reflect the implications of the Canadian government's ratification of the Kyoto Protocol.

Table C1. Electric Energy Consumption Indirect Emissions Factors for 2001
(reproduced from Table 4 of VCR 2003)

Province	kg CO ₂ -equiv/kWh
Alberta	0.985
British Columbia	0.056
Manitoba	0.0290
New Brunswick	0.510*
Newfoundland/Labrador	0.261
Northwest Territories/Nunavut	0.163
Nova Scotia	0.933
Ontario	0.302
Prince Edward Island	0.71
Quebec	0.0024
Saskatchewan	0.946**
Yukon – diesel	0.810
– system	0.048**

* no emission factor available for 2001; factor provided for 1999

** no emission factor available for 2001; factor provided for 2000

The VCR guidelines do not directly address methods for estimating the impacts of electrical power exports from industry facilities. Likewise, the special case of power imports or exports from CHP production is not directly addressed in the VCR guidelines.

3.0 UNITED STATES – INVENTORY OF US GREENHOUSE GAS EMISSIONS AND SINKS: 1990-1999 (USEPA 2001a) AND GUIDELINES FOR THE DEPARTMENT OF ENERGY 1605(B) PROGRAM (USDOE 2000)

Although EPA's US inventory is not intended to allocate emissions at the company or facility level, it does attempt to divide national GHG emissions among different sectors of the economy, estimating combustion and electricity emissions from the industrial, transportation, residential, and commercial sectors. The emissions generated by electrical power producers are "distributed to each end-use sector based upon the sector's share of national electricity. ... This method of distributing emissions assumes that each sector consumes electricity generated from an equally carbon-intensive mix of fuels and other energy sources. In reality, sources of electricity vary widely in carbon intensity (e.g., coal versus wind power). By giving equal carbon-intensity weight to each sector's electricity consumption, emissions attributed to one end-use sector may be somewhat overestimated, while emissions attributed to another end-use sector may be slightly underestimated" (USEPA 2001a, pg. 2-7).

This method misses the amounts of power generated by non-utility generators. In EPA's words, "[a]ccording to current EIA [the Energy Information Administration of the Department of Energy] sectoral definitions, the industrial sector also includes emissions from nonutility generators (e.g., independent power producers) who produce electricity for their own use, to sell to large consumers, or to sell on the wholesale electricity market. The number of nonutility generators and the quantity of electricity they produce has increased significantly as many States have begun opening their electricity markets to competition. In future inventories, these nonutility generators will be removed from the industrial sector and incorporated into a single electric power sector with electric utilities" (USEPA 2001a, pg. 2-10).

At present, therefore, EPA assigns all emissions generated by fossil fuel consumption at industrial facilities to the industrial sector, and adds the emissions generated in the production of power consumed by the industrial sector. For each sector, direct and indirect emissions are reported separately in the sector-level reporting by EPA. Indirect emissions are calculated using the average emission factor for the national electrical power grid. In the future, EPA will attempt to remove nonutility electricity generators from the industrial sector. Many of these companies have electrical power generation as their primary business. It is not known how EPA will allocate emissions from power generators that produce electricity primarily for themselves, but may export excess power or heat (USEPA 2001a).

DOE also provides guidance for estimating emissions related to purchased power (or reduced use of purchased power). It suggests using emission factors developed by DOE for average electrical power generated in each of the 50 states or case-by-case emission factors derived from information on the fuels used to generate the purchased power. The factors, and the methodology to estimate them are in *Updated State-level Greenhouse Gas Emission Factors for Electricity Generation*, published periodically by the Energy Information Administration

(USDOE 2001a). The emission factors from the March 2001 version of that document are available on the internet and are shown in Table C2 (USDOE 2001b).

Table C2. 1997-1999 US State Average CO₂ Emission Factors for Electric Utilities

State	t CO ₂ /MWh	State	t CO ₂ /MWh
Alabama	0.611	Montana	0.586
Alaska	0.563	Nebraska	0.638
Arizona	0.461	Nevada	0.755
Arkansas	0.594	New Hampshire	0.338
California	0.138	New Jersey	0.257
Colorado	0.929	New Mexico	0.952
Connecticut	0.515	New York	0.361
Delaware	0.842	North Carolina	0.564
Florida	0.65	North Dakota	0.993
Georgia	0.644	Ohio	0.823
Hawaii	0.824	Oklahoma	0.802
Idaho	0	Oregon	0.08
Illinois	0.534	Pennsylvania	0.554
Indiana	0.968	Rhode Island	0.418
Iowa	0.899	South Carolina	0.37
Kansas	0.79	South Dakota	0.325
Kentucky	0.901	Tennessee	0.565
Louisiana	0.603	Texas	0.702
Maine	0.408	Utah	0.88
Maryland incl. D.C.	0.613	Vermont	0.008
Massachusetts	0.561	Virginia	0.493
Michigan	0.79	Washington	0.083
Minnesota	0.72	West Virginia	0.895
Mississippi	0.599	Wisconsin	0.813
Missouri	0.862	Wyoming	0.995

EPA also provides emission factors for purchased electrical power in its Emissions & Generation Resource Integrated Database (E-GRID). The information in E-GRID is based on an integration of multiple federal data sources and includes information on non-utility power generators as well as utility generators. The E-GRID information can be downloaded from the internet as a self-contained, stand-alone “data browser” program and as a series of spreadsheets (available at <http://www.epa.gov/airmarkets/egrid/index.html>).

4.0 WRI/WBCSD – THE GREENHOUSE GAS PROTOCOL AND SUPPORTING GUIDANCE (WRI 2001a [replaced by WRI 2004], 2001b, 2001c)

The WRI/WBCSD Greenhouse Gas Protocol identifies three scopes for emissions reporting: Scope 1 is direct emissions; Scope 2 is indirect emissions from imports of electricity, steam, or other heat; and Scope 3 is other indirect emissions. The GHG Protocol recommends that companies account for and report at least Scopes 1 and 2. Emissions associated with the

export of electricity or steam may be included as optional information and are not netted against a facility's direct emissions. Only CO₂ must be reported (WRI 2001b, 2004).

The October 2001 Greenhouse Gas Protocol provides additional guidance for reporting indirect emissions from imported electricity, steam, and other heat (WRI 2001a). Where the guidance has been updated by WRI 2004, it is noted.

- Emissions from imported electricity can be estimated from purchase records and grid emissions factors. You should use the most reliable emissions factors available and be consistent in their use.
- Purchases of electricity by electric utilities for sale to end-use customers (e.g., an electricity utility that has a supply contract with a power generator) should be reported under Scope 2. The rationale for this is that utilities often exercise choice over where they buy their energy and this may present significant opportunities for GHG reductions.
- Trading transactions of electricity should not be reported.
- If you export electricity, heat, or steam to the grid or to another company, the emissions associated with the exports should not be deducted from Scope 1.
- Emissions from exported electricity, heat, or steam should be reported under supporting information and not deducted from any imports, as this would be inconsistent with how other exported products are accounted, e.g., export of clinker by a cement company or scrap steel by an iron and steel company.¹
- GHG emissions from activities upstream of your electricity provider, e.g., exploration, drilling, flaring, transportation, and refining should not be reported under Scope 2.”

The WRI/WBCSD protocol gives three options for selecting emission factors for imports of electricity or steam. Listed from most preferred to least preferred, these are (a) an emission factor supplied by the generator of the electricity or steam based on the fuels used or the purchasing agreement (i.e., for “green” power); (b) emission factors published by authorities for the locality or region; and (c) national average emission factors (WRI 2001b).

The calculation tools provided for the GHG Protocol contain emission factors that do not incorporate transmission and distribution losses (WRI 2001b, 2001c). WRI/WBCSD indicates that these losses can vary from 5% in OECD countries to 20% in developing countries (WRI 2001b).

The WRI/WBCSD worksheet “Calculating CO₂ emissions from stationary combustion” contains a number of spreadsheets, including several of interest in the context of estimating indirect emissions (WRI 2001c). They deal with

- emissions resulting from electricity and/or steam import (worksheet 2)

¹ The March 2004 GHG Protocol Revised Edition provides the following guidance: “Emissions associated with the sale of own-generated electricity to another company are not deducted/netted from Scope 1 [direct emissions]. ... Emissions associated with the sale/transfer of own-generated electricity may be reported in optional information” (WRI 2004).

- emissions resulting from electricity and/or steam export to grid or through direct supply contract (worksheet 3)
- emissions from CHP systems calculated using the “efficiency of heat and power production” (worksheet CHP option 1)
- emissions from CHP systems calculated using the “work potential” method (worksheet CHP option 2)

Emissions attributed to imported electricity or steam are calculated in worksheet 2 simply by multiplying the appropriate emission factor by the amounts of power or steam imported.

In worksheet 3, the impact of electricity or steam exports is calculated by dividing the facility’s electricity and steam generation-related emissions between facility emissions and exported emissions according to the relative amounts of electricity/steam used internally and exported.

Worksheets CHP Option 1 and CHP Option 2 are of interest in the context of indirect emissions because they attempt to divide the emissions from CHP systems between the steam and power produced, a topic addressed in detail in Annex D of these tools.

ANNEX D

ALLOCATING GREENHOUSE GAS EMISSIONS FROM COMBINED HEAT AND POWER (CHP) SYSTEMS: RECOMMENDED GUIDANCE AND REVIEW OF METHODS

This Annex contains the material presented on the efficiency method in Section 10.7 of *Calculation Tools for Estimating Greenhouse Gas Emissions from Wood Products Plants* and additional information on other methods for allocating CHP emissions.

1.0 RECOMMENDED GUIDANCE

Where electricity is produced by combined heat and power (CHP) systems, it may be necessary to allocate the emissions from the CHP system to the various output energy streams. Of course, if the manufacturing plant owns the CHP system and uses all of its output, this is not necessary because all the emissions are direct emissions for the plant. In many cases, however, a plant may either receive CHP energy from an outside provider or export a portion of its own CHP output. For instance, if a plant is importing steam from a nearby power plant, it is necessary to estimate indirect emissions associated with the imported steam. Likewise, if a manufacturer is exporting power from a CHP system but using the steam internally, it may be necessary to estimate how much of its emissions to attribute to the exported electricity.

Although there are several methods for allocating emissions from CHP systems, the efficiency method is recommended in these calculation tools because it attempts to relate energy outputs to the amounts of fuel used to generate them and, by extension, to the GHGs produced in generating them. The efficiency method is one of two methods recommended by WRI/WBCSD (termed “CHP option 1” by WRI/WBCSD) (WRI 2001b, c).

2.0 OVERVIEW OF METHODS

There are at least four methods that can be applied in a broad fashion for allocating GHG emissions among electricity and steam or hot water outputs from CHP plants. All four methods presented herein involve estimating total CHP system emissions based on fossil fuel combustion and distributing the total emissions among the various output streams. Allocations are made based either on the perceived value of the energy outputs, the “useful energy” content of each energy output, or by estimating the amount of original fuel energy expended in creating each energy output.

The financial value method of allocating emissions involves assigning a monetary value to each energy output stream and allocating emissions according to the value of the energy. The methods for determining these values are site specific, so no attempt will be made to present alternative ways to use this allocation method. Therefore, the guidance recommends that companies not use the financial method to allocate emissions from CHP systems.

The efficiency method is based on allocating emissions according to the amount of fuel used to produce each energy output. The method uses either assumed or estimated efficiencies for conversion of energy at various points in the process to back calculate the amounts of fuel associated with each output energy stream. This method can be used in a simplified or detailed manner, and is the approach recommended in the wood products GHG calculation tools.

The heat content and work potential methods allocate emissions based on the amount of useful energy in each energy output. Both of these allocation methods consider the energy content of electrical power to be of “complete utility,” such that all of the energy in the electricity is consumed in a useful fashion by a process. The primary difference between the allocation methods is in regard to how the energy content associated with steam is determined. The heat content method assumes that the useful energy content of steam (or hot water) is equivalent to the heat that can be extracted from it, whereas the work potential method assumes that the useful energy content is equivalent to the maximum amount of work that can be extracted from the steam. Accordingly, the work potential method is not recommended for allocating emissions from CHP systems which incorporate a hot water energy output stream (work cannot be extracted from hot water).

The efficiency, heat content, and work potential methods will be described briefly, followed by illustrative examples of allocating GHG emissions for a hypothetical CHP system by each method.

2.1 Efficiency Method – Note: Section 2.1.1 herein is identical to Section 10.7.1 in the report

2.1.1 *Simplified Efficiency Method*

The efficiency method requires use of assumed efficiency factors for the production of power and steam, or actual efficiency factors for each steam or power generation device based on detailed process design and operating information. It is assumed that the efficiency of producing hot water is the same as the efficiency of producing steam. The simplest approach to applying the efficiency method is to assign a single efficiency factor to all power output and a single efficiency factor to all heat (steam and hot water) output. This information is used to compute an efficiency ratio equal to the heat production efficiency divided by the power production efficiency. For example, if the CHP system produces steam at 80% efficiency and power at 40% efficiency the ratio would be 2. The efficiency ratio is used rather than the individual efficiencies because (a) it is the ratio that controls the allocation of emissions rather than the individual efficiencies, and (b) the individual efficiencies are constrained by the energy balance so it is not possible to specify both independently. Emissions from the CHP system are allocated between the heat and power outputs, based on this ratio of efficiencies, using Equations 1 and 2. This approach is referred to in this report as the simplified efficiency method. The simplified efficiency method is the method recommended for manufacturing plants that lack, or choose not to use, detailed design and operating data from CHP systems.

$$E_H = \left\{ \frac{H}{H + P \times R_{eff}} \right\} \times E_T; \quad R_{eff} = \frac{e_H}{e_P} \quad (Eq. 1)$$

where: E_H = emissions share attributable to heat production, t GHG/y
 E_T = total emissions from the CHP plant, t GHG/y
 H = heat output, GJ/y
 P = power output, GJ/y
 R_{eff} = ratio of heat production efficiency to power production efficiency
 e_H = assumed efficiency of typical heat production (default = 0.8)
 e_P = assumed efficiency of typical electric power production (default = 0.35)

The emission share attributable to electric power production is assigned from the relation:

$$E_P = E_T - E_H \quad (Eq. 2)$$

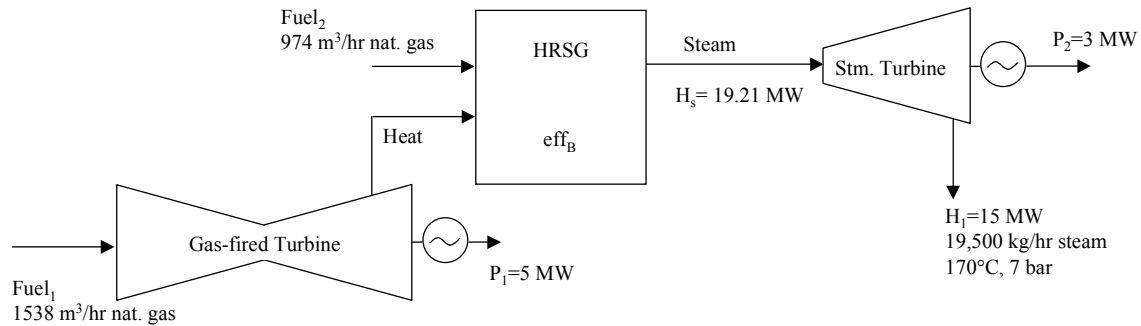
where: E_P = emissions share attributable to electric power production

In these calculations, the heat in steam can be corrected to reflect the amount of heat in returned condensates.

In using the simplified efficiency method, we recommend that an efficiency of 0.35 be used for power generation and 0.8 be used for steam (or hot water) generation, corresponding to a ratio of efficiencies (R_{eff}) of 2.3. The first example calculation below makes use of these recommended default efficiency factors.

Example Calculation: Allocating CHP emissions to three output streams – simplified efficiency method with default efficiency factors.

A manufacturing plant has the CHP system shown in the figure, but it is lacking (or chooses not to use) detailed energy balance information. Instead, the company chooses to use the simplified efficiency method and the default efficiencies recommended herein: 0.35 for power generation and 0.8 for steam generation.



Using these assumed efficiencies, emissions can be allocated among the three outputs of the CHP system as follows (using a basis of one hour of operation):

Total system emissions:

Fuel₁:

$$\text{CO}_2 \quad (1538 \text{ m}^3/\text{hr}) \times (0.0371 \text{ GJ HHV/m}^3) \times (50.2 \text{ kg CO}_2/\text{GJ HHV}) = 2864 \text{ kg CO}_2/\text{hr}$$

$$\text{CH}_4 \quad (1538 \text{ m}^3/\text{hr}) \times (0.0371 \text{ GJ/m}^3) \times (0.0005 \text{ kg CH}_4/\text{GJ}) \times (21 \text{ CO}_2\text{-equiv/CH}_4) \\ = 0.60 \text{ kg CO}_2\text{-equiv/hr}$$

$$\text{N}_2\text{O} \quad (1538 \text{ m}^3/\text{hr}) \times (0.0371 \text{ GJ/m}^3) \times (0.0001 \text{ kg N}_2\text{O/GJ}) \times (310 \text{ CO}_2\text{-equiv/N}_2\text{O}) \\ = 1.77 \text{ kg CO}_2\text{-equiv/hr}$$

$$\text{Total Fuel}_1 \text{ emissions} = 2866 \text{ kg CO}_2\text{-equiv/hr}$$

Fuel₂:

$$\text{CO}_2 \quad (974 \text{ m}^3/\text{hr}) \times (0.0371 \text{ GJ/m}^3) \times (50.2 \text{ kg CO}_2/\text{GJ}) = 1814 \text{ kg CO}_2/\text{hr}$$

$$\text{CH}_4 \quad (974 \text{ m}^3/\text{hr}) \times (0.0371 \text{ GJ/m}^3) \times (0.0013 \text{ kg CH}_4/\text{GJ}) \times (21 \text{ CO}_2\text{-equiv/CH}_4) \\ = 0.99 \text{ kg CO}_2\text{-equiv/hr}$$

$$\text{N}_2\text{O} \quad (974 \text{ m}^3/\text{hr}) \times (0.0371 \text{ GJ/m}^3) \times (0.0001 \text{ kg N}_2\text{O/GJ}) \times (310 \text{ CO}_2\text{-equiv/N}_2\text{O}) \\ = 1.12 \text{ kg CO}_2\text{-equiv/hr}$$

$$\text{Total Fuel}_2 \text{ emissions} = 1816 \text{ kg CO}_2\text{-equiv/hr}$$

$$\text{Total CHP system emissions} = 2866 + 1816 = 4682 \text{ kg CO}_2\text{-equiv/hr}$$

$$\text{Total system power output} = P_1 + P_2 = 8 \text{ MW}$$

$$R_{eff} = \frac{0.8}{0.35} = 2.3$$

$$E_H = \left\{ \frac{15 \text{ MW}}{15 \text{ MW} + (8 \text{ MW} \times 2.3)} \right\} \times 4682 \text{ kg CO}_2\text{eq} = 2103 \text{ kg CO}_2\text{eq} = 17,700 \text{ t CO}_2 \text{ equiv/y at 350 d/y operation}$$

$$E_P = 4682 \text{ kg CO}_2\text{eq} - 2103 \text{ kg CO}_2\text{eq} = 2579 \text{ kg CO}_2\text{eq} = 21,700 \text{ t CO}_2 \text{ equiv/yr at 350 d/y operation}$$

Using the simplified efficiency method with default power and steam efficiency factors, therefore, the emissions from the CHP system are allocated to the output streams in the following percentages:

- Percentage of CHP emissions to heat output = $100 \times 2103 / 4682 = 44.9\%$
- Percentage of CHP emissions to power output = $100 \times 2579 / 4682 = 55.1\%$

These percentages can be used to allocate all GHG emissions from the CHP system.

Emission factors can be developed for the energy outputs:

- Emission factor for CHP heat output = $(2103 \text{ kg CO}_2\text{-equiv/hr}) / 15 \text{ MW}$
= $140 \text{ kg CO}_2\text{-equiv./MWh}$
- Emission factor for CHP power output = $(2579 \text{ kg CO}_2\text{-equiv/hr}) / 8 \text{ MW}$
= $322 \text{ kg CO}_2\text{-equiv/MWh}$

2.1.2 Detailed Efficiency Method

Application of the relations in Equations 1 and 2 to allocate GHG emissions among the energy outputs of a simple CHP system which includes only a single heat stream (in the form

of steam or hot water) and a single electric power stream may be fairly straightforward. However, many industrial CHP systems include multiple heat output streams and incorporate electric power production from multiple generators driven by different motive forces. To use the efficiency method to allocate GHG emissions among the multiple energy outputs of more complex CHP systems, Equations 1 and 2 can be modified to more general forms such as:

$$E_{HI} = \left\{ \frac{\left(\frac{H_1}{e_{HI}} \right)}{\left(\frac{H_1}{e_{HI}} \right) + \left(\frac{H_2}{e_{H2}} \right) + \dots + \left(\frac{P_1}{e_{P1}} \right) + \left(\frac{P_2}{e_{P2}} \right) + \dots} \right\} \times E_T \quad (\text{Eq. 3})$$

$$E_{PI} = \left\{ \frac{\left(\frac{P_1}{e_{PI}} \right)}{\left(\frac{H_1}{e_{HI}} \right) + \left(\frac{H_2}{e_{H2}} \right) + \dots + \left(\frac{P_1}{e_{PI}} \right) + \left(\frac{P_2}{e_{P2}} \right) + \dots} \right\} \times E_T \quad (\text{Eq. 4})$$

Where: E_{HI} = emissions share attributable to heat production as contained in steam stream 1

E_{PI} = emissions share attributable to electric power production via generator 1

E_T = total emissions from the CHP plant

H_1 = heat output contained in steam stream 1

H_2 = heat output contained in steam stream 2

P_1 = power output from generator 1

P_2 = power output from generator 2

e_{HI} = overall efficiency of producing heat contained in steam stream 1

e_{H2} = overall efficiency of producing heat contained in steam stream 2

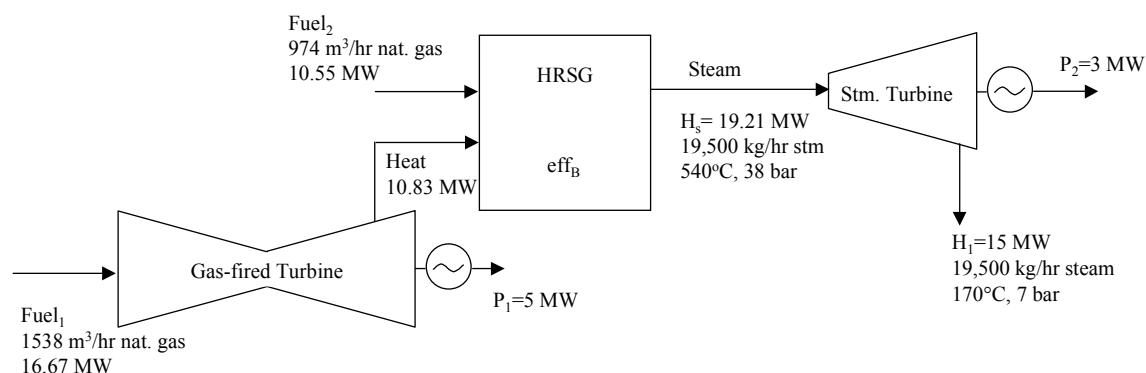
e_{PI} = overall efficiency of producing electric power via generator 1

e_{P2} = overall efficiency of producing electric power via generator 2

Manufacturing facilities may already have energy balances that incorporate the type of information needed to perform the detailed efficiency method. In these cases, the efficiency method is applied by using the energy balances to estimate the amount of fuel required to produce each CHP output stream. This can then be converted into GHG allocations for each stream. As in the simplified efficiency method, hot water streams are treated in the same manner as steam outputs.

Example Calculation: Allocating emissions from a complex CHP system.

The figure depicts a hypothetical CHP system that includes three energy output streams (one steam stream, H_1 , and two power outputs, P_1 and P_2) and incorporates two fuel inputs (one to the gas-fired turbine and a second to the heat recovery steam generator (HRSG)). In order to use Equations 3 and 4 to allocate GHG emissions among the three energy outputs of this CHP system, efficiency factors for each output must be either developed or assumed.



The CHP system emissions are the same as those calculated in the previous example:

Total Fuel₁ emissions = 2866 kg CO₂-equiv/hr

Total Fuel₂ emissions = 1816 kg CO₂-equiv/hr

The efficiency for P_1 , the power output from the gas-fired turbine, has been estimated at 0.3 (30%) based on information from the manufacturer. Mechanical losses in the gas turbine are approximately 5%, so the “efficiency”¹ of producing the (waste) heat in the turbine exhaust is $1 - 0.05 - 0.3 = 0.65$, or 65%. The emissions from combustion of fuel in the gas-fired turbine can now be allocated between P_1 and the waste heat using Equations 3 and 4, with one hour of operation as the basis for the calculations:

$$E_{P1} = \left\{ \frac{\left(\frac{P_1}{e_{P1}} \right)}{\left(\frac{P_1}{e_{P1}} \right) + \left(\frac{Heat}{e_{Heat}} \right)} \right\} \times E_{F1} = \left\{ \frac{\left(\frac{5MW}{0.3} \right)}{\left(\frac{5MW}{0.3} \right) + \left(\frac{10.83MW}{0.65} \right)} \right\} \times 2866 kgCO_2 eq = 1433 kgCO_2 eq$$

¹ The term “efficiency” is used here to represent the amount of waste heat generated in the gas turbine relative to the amount of fuel energy input to the gas turbine. Although waste heat generation rates are not typically characterized by efficiency factors, the factor is required for the use of the efficiency method of emissions allocation in this example because the waste heat from the gas turbine is an energy input to the HRSG.

$$E_{Heat} = \left\{ \frac{\left(\frac{Heat}{e_{Heat}} \right)}{\left(\frac{P_1}{e_{P1}} \right) + \left(\frac{Heat}{e_{Heat}} \right)} \right\} \times E_{F1} = \left\{ \frac{\left(\frac{10.83MW}{0.65} \right)}{\left(\frac{5MW}{0.3} \right) + \left(\frac{10.83MW}{0.65} \right)} \right\} \times 2866kgCO_2eq = 1433kgCO_2eq$$

Development of efficiency factors for H₁ and P₂ is complicated by the fact that the CHP system incorporates two fuel inputs (F₁ and F₂). Steam energy produced in the HRSG is derived from a combination of waste heat from the gas-fired turbine (heat that originated from part of the energy in fuel stream F₁) and supplemental firing of natural gas (often termed a duct burner). In allocating emissions associated with operating the HRSG, the exhaust from the gas turbine is treated as a fuel and the emissions allocated to this stream (E_{Heat}) are added to the emissions associated with F₂ (E_{F2}), and these total emissions (E_{F2}) are allocated between H₁ and P₂.

Differing efficiencies are associated with converting each of these two energy sources into steam in the HRSG. The manufacturer has information that indicating that the efficiency of the HRSG in converting heat in the turbine exhaust gas into steam energy is 80%. The efficiency associated with combustion of auxiliary fuel in the duct burner is 100% (this is typically true of supplementally fired HRSGs). This information can be used to develop an overall efficiency of the HRSG:

$$eff_B = 100\% \times \left(\frac{10.55MW}{10.55MW + 10.83MW} \right) + 80\% \times \left(\frac{10.83MW}{10.55MW + 10.83MW} \right) = 90\%$$

It is assumed that the efficiency associated with H₁ is equivalent to that of producing steam in the HRSG (H_s), 90%. The plant has information indicating that the efficiency of the back pressure steam turbine in converting expansion into mechanical work (isotropic expansion efficiency) is 75%, and the generator which converts the mechanical work into electrical power is 95% efficient. Therefore, the efficiency of producing electrical power output P₂ is:

$$(eff_B) \times (eff_{turbine}) \times (eff_{generator}) = (0.9) \times (0.75) \times (0.95) = 0.64, \text{ or } 64\%.$$

$$E_{F2'} = E_{F2} + E_{Heat} = 1816 + 1433 = 3249kgCO_2eq$$

$$E_{P2} = \left\{ \frac{\left(\frac{3MW}{0.64} \right)}{\left(\frac{3MW}{0.64} \right) + \left(\frac{15MW}{0.9} \right)} \right\} \times 3249kgCO_2eq = 713kgCO_2eq$$

$$E_{H1} = \left\{ \frac{\left(\frac{15MW}{0.9} \right)}{\left(\frac{3MW}{0.64} \right) + \left(\frac{15MW}{0.9} \right)} \right\} \times 3249kgCO_2eq = 2536kgCO_2eq$$

The table presents a summary of emissions and emission factors for the three outputs in this example.

	Total Energy (MW)	Efficiency	Steam Temp. (°C)	Steam Press. (bar)	CO ₂ Emissions (kg CO ₂)	CO ₂ Emission Factor (kg CO ₂ /MWh)
P ₁ (Electricity)	5	0.3	N/A	N/A	1433	286
P ₂ (Electricity)	3	0.64	N/A	N/A	713	238
H ₁ (Steam)	15	0.9	170	7	2536	169
Total					4682	

2.2 Heat Content Method

In the heat content method, all the energy in electrical power is considered useful; however, only the fraction of the total energy in steam (or hot water) that can be used for process heating is considered useful. Furthermore, it is assumed that the steam is used for indirect heating, with condensates returned to the CHP system. Alternatively, if the condensates are not returned or if a hot water output stream is considered in the allocation, reference conditions other than those shown below may be used (e.g., the temperature and pressure of boiler feed water). Therefore, the useful energy content of steam can be calculated using Equation 5:

$$Useful\ Energy = F_i \times (H_i - H_{ref}) \quad (Eq. 5)$$

Where: F_i = the mass of steam in tonnes (1000 kg)

H_i = the specific enthalpy of steam flow i , in kJ/kg

H_{ref} = the specific enthalpy at reference conditions (corresponding to returned condensates, assume at 100 °C and 1 atm pressure)

If the quantity of steam (or hot water) is given in terms of total energy, the corresponding mass of steam (or hot water) can be calculated using Equation 6:

$$F_i = \frac{total\ energy}{H_i} \quad (Eq. 6)$$

As an example, consider a CHP system which emits a total of 174,000 tonnes of carbon dioxide per year with total energy outputs as shown in Table D1. The useful energy content of electricity is equivalent to the total energy, and for the three steam streams the useful energy is calculated from Equation 5. Allocated carbon dioxide emissions and an emission factor (ton CO₂ per GJ of total energy) for each energy output are also shown in Table D1.

Table D1. Allocation of GHG Emissions Based on the Heat Content Method

Combined Heat and Power system total CO ₂ emissions = H = 174,000 tonnes						
	A	B	C	D	E	F
	Total Energy	Steam Temp.	Steam Press.	Useful Energy Eq. 1	CO ₂ Emissions E=H×D _i /ΣD	CO ₂ Emission Factor F=E/A
	(GJ)	(°C)	(barg)	(GJ)	(tonne CO ₂)	(tonne CO ₂ /GJ)
Electricity	245	N/A	N/A	245	14,167	57.8
Steam 1	1355	400	40	1178	68,120	50.3
Steam 2	1100	300	20	947	54,762	49.8
Steam 3	750	200	10	639	36,951	49.3
Total	3450			3009	174,000	

2.3 Work Potential Method

In other applications, the steam generated in the CHP system may be used to drive mechanical equipment. In these cases, the work potential method of allocating emissions may be more appropriate. The work potential method is not appropriate for CHP systems which include a hot water output stream. As in the heat content method, the work potential method considers all the energy contained in electrical power to be useful, and a fraction of the energy in steam to be useful. However, in the work potential method the useful energy fraction of the total energy in steam corresponds to the maximum amount of work that could be done by the steam in an open (flow), steady state, thermodynamically reversible process. The thermodynamic term for this amount of work is the “availability” or the “exergy.” The exergy of a particular stream (the useful energy parameter corresponding to the work potential method) relative to a reference case can be computed using Equation 7:

$$Useful\ Energy = F_i \times \left\{ \left[H_i - (T_{ref} + 273) \times S_i \right] - \left[H_{ref} - (T_{ref} + 273) \times S_{ref} \right] \right\} \quad (Eq. 7)$$

where: F_i = the mass of steam in tonnes (1000 kg)

H_i = the specific enthalpy of steam flow i , in kJ/kg

H_{ref} = the specific enthalpy at reference conditions (corresponding to returned condensates, assume at 100 °C and 1 atm pressure)

S_i = the specific entropy of steam flow i , in kJ/kg·K

S_{ref} = the specific entropy at reference conditions

T_{ref} = the temperature at reference conditions

Table D2 presents the allocated carbon dioxide emissions and emission factors for each of the energy outputs for the same example CHP system computed by the work potential method.

Table D2. Allocation of GHG Emissions Based on the Work Potential Method

Combined Heat and Power system total CO ₂ emissions = H = 174,000 tonnes						
	A Total Energy (GJ)	B Steam Temp. (°C)	C Steam Press. (barg)	D Useful Energy Eq. 3 (GJ)	E CO ₂ Emissions E=H×D _i /ΣD (tonne CO ₂)	F CO ₂ Emission Factor F=E/A (tonne CO ₂ /GJ)
Electricity	245	N/A	N/A	245	48,200	196.8
Steam 1	1355	400	40	320	63,000	46.5
Steam 2	1100	300	20	210	41,200	37.5
Steam 3	750	200	10	109	21,500	28.7
Total	3450			884	174,000	

ANNEX E

GREENHOUSE GASES FROM VEHICULAR TRAFFIC AND MACHINERY: OVERVIEW OF METHODS IN EXISTING PROTOCOLS

1.0 OVERVIEW

National inventories of GHG emissions from mobile sources focus on highway travel and rail, air, and water transport. Highway travel is the most significant component of mobile source emissions, by far. Some of the mobile emissions of interest to wood products plants, for example emissions from vehicles used at industrial facilities or in forestry operations, get little or no attention. Some of the inventory documents suggest emission factors for non-highway utility and construction vehicles that appear to be applicable to some of these sources.

The WRI/WBCSD GHG Protocol distinguishes between direct and indirect emissions from mobile sources based on the ownership or control of the vehicles. The WRI/WBCSD Protocol Scope 1 reporting requirements include all direct emissions, regardless of where they occur (WRI 2004). Because corporate inventories often include both on-site and off-site vehicular emissions, references are given in this annex that can be used to estimate emissions from a variety of off-road vehicles and equipment that are sometimes used by the forest products industry.

Companies interested in estimating the emissions from company-owned on-road vehicles can use information from a variety of organizations, including IPCC (1997c) and WRI/WBCSD (WRI 2001d). The WRI/WBCSD calculation tools for transportation emissions are available on the internet (WRI 2001d) and are briefly summarized here as well. The Excel[®] workbook that accompanies this report incorporates the transportation calculation tools from WRI/WBCSD.

1.1 Carbon Dioxide

Essentially all protocols suggest that CO₂ emissions from transportation vehicles and equipment be calculated from fuel consumption and carbon content data. This is affirmed in the Revised 1996 IPCC Guidelines (IPCC 1997c), the May 2000 IPCC Good Practices document (IPCC 2000), the EMEP/CORINAIR Atmospheric Emission Inventory Guidebook, second edition (EEA 1999), and the WRI/WBCSD GHG Protocol calculation tools (WRI 2001d). A number of the protocols also give emission factors (kg CO₂/vehicle km) as a method for cross checking the estimates.

It is reasonable to expect that companies will be able to estimate the consumption and carbon content of fuels used in on-site vehicles. Lacking site-specific information on the carbon content of fuel, companies can use the values published by national authorities. For a number of countries and fuels, these values are listed in Annex A of these tools.

In some cases, authorities issue a single emission factor shown in CO₂-equivalents that incorporates emissions of CH₄ and N₂O. In the Australian Greenhouse Challenge, for instance, the emission factors not only include all three GHGs, they also include the impact

of upstream emissions from fuel extraction, processing, and transportation (i.e., full fuel cycle emissions).

1.2 Methane and Nitrous Oxide

1.2.1 IPCC's Revised 1996 Guidelines and May 2000 Best Practices Document

The Reference Manual of IPCC's Revised 1996 Guidelines contains emission factors for "surface non-road sources." (IPCC 1997c, page 1.88) The Revised 1996 Guidelines include emission factors published by EMEP/CORINAIR Atmospheric Emissions Inventory Handbook, most recently updated in 1996, and by USEPA. Both sets of emission factors are shown in Tables E1 and E2.

Table E1. Fuel Consumption-Based N₂O and CH₄ Emission Factors for Non-Road Mobile Sources and Machinery (IPCC 1997c)
(IPCC Revised 1996 Guidelines taken from EMEP/CORINAIR)

Source and Engine Type	g N ₂ O/kg fuel	g N ₂ O/MJ	g CH ₄ /kg fuel	g CH ₄ /MJ
Forestry – diesel	1.3	0.03	0.17	0.004
Industry – diesel	1.3	0.03	0.17	0.004
Railways – diesel	1.2	0.03	0.18	0.004
Industry – gasoline 4 stroke	0.08	0.002	2.2	0.05
Forestry – gasoline 2 stroke	0.02	0.0004	0.04	7.7
Industry – gasoline 2 stroke	0.02	0.0004	0.05	6.0

Table E2. N₂O and CH₄ Emission Factors for Non-Highway Vehicles (IPCC 1997c)
(IPCC Revised 1996 Guidelines taken from USEPA)

Source and Engine Type	g N ₂ O/kg fuel	g N ₂ O/MJ	g CH ₄ /kg fuel	g CH ₄ /MJ
Ships and boats				
Residual	0.08	0.002	0.23	0.005
Distillate	0.08	0.002	0.23	0.005
Gasoline	0.08	0.002	0.23	0.005
Locomotives				
Residual	0.08	0.002	0.25	0.006
Diesel	0.08	0.002	0.25	0.006
Coal	0.08	0.002	0.25	0.006
Farm equipment				
Gas/tractor	0.08	0.002	0.45	0.011
Other gas	0.08	0.002	0.45	0.011
Diesel/tractor	0.08	0.002	0.45	0.011
Other diesel	0.08	0.002	0.45	0.011
Construction				
Gas construction	0.08	0.002	0.18	0.004
Diesel construction	0.08	0.002	0.18	0.004
Other non-highway				
Gas snowmobile	0.08	0.002	0.18	0.004
Gas small utility	0.08	0.002	0.18	0.004
Gas heavy duty utility	0.08	0.002	0.18	0.004
Diesel heavy duty utility	0.08	0.002	0.18	0.004

1.2.2 EMEP/CORINAIR Atmospheric Emissions Inventory Guidebook (EEA 1999)

The EMEP/CORINAIR Atmospheric Emissions Inventory Guidebook contains a second set of emission factors that are based on the power output of the engine. These emission factors are presented in a way that allows them to be adjusted based on the engine design and the age of the engine. They can be used to estimate emissions from all fossil fuel fired engines. The emission factors and the needed adjustment factors are shown in Table E3 (EEA 1999).

Table E3. CORINAIR Engine Output-Based N₂O and CH₄ Emission Factors for Non-Road Mobile Sources and Machinery (EEA 1999)

Source and Engine Type/Size		N ₂ O (g/kWh)	CH ₄ (g/kWh)
Baseline factors			
Diesel engines		0.35	0.05
2-stroke gasoline	0-2 kW	0.01	6.60
2-stroke gasoline	2-5 kW	0.01	3.55
2-stroke gasoline	5-10 kW	0.01	2.70
2-stroke gasoline	10-18 kW	0.01	2.26
2-stroke gasoline	18-37 kW	0.01	2.01
2-stroke gasoline	37-75 kW	0.01	1.84
2-stroke gasoline	75-130 kW	0.01	1.76
2-stroke gasoline	130-300 kW	0.01	1.69
4-stroke gasoline	0-2 kW	0.03	5.30
4-stroke gasoline	2-5 kW	0.03	2.25
4-stroke gasoline	5-10 kW	0.03	1.40
4-stroke gasoline	10-18 kW	0.03	0.96
4-stroke gasoline	18-37 kW	0.03	0.71
4-stroke gasoline	37-75 kW	0.03	0.54
4-stroke gasoline	75-130 kW	0.03	0.46
4-stroke gasoline	130-300 kW	0.03	0.39
4-stroke LPG		0.05	1.0
Pollutant weighting factors for diesel engines (multiply baseline factors shown above by these values)			
Naturally aspirated direct injection		1.0	0.8
Turbo-charged direct injection		1.0	0.8
Intercooled turbo-charged direct injection		1.0	0.8
Intercooled turbo-charged prechamber injection		1.0	0.9
Naturally aspirated prechamber injection		1.0	1.0
Turbo-charged prechamber injection		1.0	0.95
Degradation factors (increase emission factors calculated above by these values)			
Diesel engines		0% per year	1.5% per year
2-stroke gasoline engines		0% per year	1.4% per year
4-stroke gasoline and LPG engines		0% per year	1.4% per year

1.2.4 Finland - Greenhouse Gas Emissions and Removals in Finland – April 9, 2001

The Finnish inventory document, *Greenhouse gas emissions and removals in Finland – April 9, 2001*, contains a list of emission factors for “small scale combustion,” most of which are from the CORINAIR Emission Inventory Handbook. Several of the factors of interest to the forest products industry are listed in Table E4 (Technical Research Center of Finland 2001).

Table E4. Finnish Emission Factors for Forestry and Industrial Machinery
(Technical Research Center of Finland 2001)

Source	Fuel	CH ₄ (mg/MJ)	N ₂ O (mg/MJ)
Forest machinery – diesel	light fuel oil	3.9	31.5
Forest machinery – Otto engine	gasoline	138.3	0.3
Construction machinery – diesel	light fuel oil	4.1	30.8
Construction machinery – Otto engine	gasoline	133.3	1.7
Other machinery – Otto engine	gasoline	93.8	1.1
Other machinery – diesel	light fuel oil	4.0	30.9
Other machinery – diesel	LPG	63.9	3.2

1.2.5 *Canada - Guide to Entity- and Facility-Based Reporting, Canada's Climate Change Voluntary Challenge and Registry (VCR) – 2003*

The VCR guidance provides a set of emission factors for CO₂, CH₄, and for N₂O for use in estimating emissions related to consumption of transportation fuels. VCR also provides a set of emission factors (in terms of CO₂ equivalents) which can be used to estimate indirect emissions for transportation (e.g., rail transportation, bus travel, etc.). The VCR recommended factors are reproduced in Tables E5 and E6.

Table E5. Canadian Emission Factors for Common Transportation Fuels
(reproduced from Table 5 of VCR 2003)

Vehicle (fuel)	Carbon Dioxide CO ₂	Methane CH ₄	Nitrous Oxide N ₂ O
Car (gasoline)	2.360 kg/l	0.00025 kg/l	0.00026 kg/l
Car (diesel)	2.730 kg/l	0.00005 kg/l	0.0002 kg/l
Light truck (gasoline)	2.360 kg/l	0.00019 kg/l	0.00041 kg/l
Light truck (diesel)	2.730 kg/l	0.00007 kg/l	0.0002 kg/l
Heavy-duty vehicle (gasoline)	2.360 kg/l	0.00017 kg/l	0.001 kg/l
Heavy-duty truck (diesel)	2.730 kg/l	0.00012 kg/l	0.00008 kg/l
Motorcycle (gasoline)	2.360 kg/l	0.0014 kg/l	0.000046 kg/l
Propane vehicles	1.500 kg/l	0.00052 kg/l	0.000028 kg/l
Natural gas vehicles	2.758 kg/kg	0.03210 kg/kg	0.00009 kg/kg
Off-road vehicles (gasoline)	2.360 kg/l	0.0027 kg/l	0.00005 kg/l
Off-road vehicles (diesel)	2.730 kg/l	0.00014 kg/l	0.0011 kg/l
Railroad locomotives (diesel)	2.730 kg/l	0.00015 kg/l	0.0011 kg/l
Small marine transport (gasoline)	2.360 kg/l	0.0013 kg/l	0.00006 kg/l
Marine transport (diesel)	2.730 kg/l	0.00015 kg/l	0.00100 kg/l
Marine transport (light “distillate” oil)	2.830 kg/l	0.0003 kg/l	0.00007 kg/l
Marine transport (heavy “residual” oil)	3.090 kg/l	0.0003 kg/l	0.00008 kg/l
Aircraft (aviation gasoline)	2.330 kg/l	0.00219 kg/l	0.00023 kg/l
Aircraft (jet fuel/aviation turbo)	2.550 kg/l	0.00008 kg/l	0.00025 kg/l

Table E6. Canadian Indirect Emission Factors for Transportation
(reproduced from Table 6 of VCR 2003)

Rail transportation (freight)	0.0162 kg CO ₂ -equiv/tonne-km
Rail transportation (passengers)	0.1033 kg CO ₂ -equiv/passenger-km
Bus travel (urban)	0.1589 kg CO ₂ -equiv/passenger-km
Bus travel (inter-city)	0.0587 kg CO ₂ -equiv/passenger-km
Air travel	34.1 kg CO ₂ -equiv/passenger (take-off) 0.1046 kg CO ₂ -equiv/passenger (in air)

1.2.6 WRI/WBCSD Greenhouse Gas Protocol and Supporting Documents

Noting that CH₄ and N₂O emissions “comprise a relatively small proportion of overall transportation emissions,” the WRI/WBCSD Protocol includes only CO₂ emissions from mobile sources. Companies are given the option of estimating CH₄ and N₂O emissions from mobile sources (WRI 2001d). Tables E7 and E8 contain the WRI/WBCSD GHG Protocol default emission factors according to fuel use and distance traveled (WRI 2001d).

Table E7. Default Emission Factors for Different Transportation Fuels (WRI 2001d)

Fuel type	Based on Lower Heat Value kg CO ₂ /GJ
Gasoline/petrol	69.25
Kerosene	71.45
Jet fuel	70.72 (EIA)
Aviation gasoline	69.11 (EIA)
Diesel	74.01
Distillate fuel oil no.1	74.01
Distillate fuel oil no.2	74.01
Residual fuel oil no. 4	74.01
Residual fuel oil no. 5	77.30
Residual fuel oil no. 6	77.30
LPG	63.20
Lubricants	73.28
Anthracite	98.30
Bituminous coal	94.53
Butane	
Propane	62.99 (EIA)
Sub-bituminous coal	96.00
Wood, wood residual fuels	100.44 (EIA)
Natural gas	56.06

Table E8. Default Fuel Economy Factors for Different Types of Mobile Sources and Activity Data (WRI 2001d)

Vehicle Type	Liters/100 km	mpg	gram CO ₂ /km
New small gas/electric hybrid	4.2	56	100.1
Small gas auto, hwy	7.3	32	175.1
Small gas auto, city	9.0	26	215.5
Medium gas auto, hwy	7.8	30	186.8
Medium gas auto, city	10.7	22	254.7
Large gas auto, hwy	9.4	25	224.1
Large gas auto, city	13.1	18	311.3
Medium station wagon, hwy	8.7	27	207.5
Medium station wagon, city	11.8	20	280.1
Mini van, hwy	9.8	24	233.5
Mini van, city	13.1	18	311.3
Large van, hwy	13.1	18	311.3
Large van, city	16.8	14	400.2
Mid size pick-up truck, hwy	10.7	22	254.7
Pick-up truck, city	13.8	17	329.6
Large pick-up truck, hwy	13.1	18	311.3
Large pick-up truck, city	15.7	15	373.5
LPG auto	11.2	21	266
Diesel auto	9.8	24	233
Gasoline light truck	16.8	14	400
Gasoline heavy truck	39.2	6	924
Diesel light truck	15.7	15	374
Diesel heavy truck	33.6	7	870
Light motorcycle	3.9	60	93
Diesel bus	35.1	6.7	1035

ANNEX F

GREENHOUSE GASES FROM WASTE MANAGEMENT AT WOOD PRODUCT PLANTS: RECOMMENDED APPROACH AND REVIEW OF EXISTING METHODS

1.0 RECOMMENDED APPROACH FOR ESTIMATING CH₄ EMISSIONS FROM LANDFILLS [Note: Much of Section 1.0 is identical to Section 12 in the Calculation Tools Report]

These calculation tools have been developed assuming that many companies will include company-owned landfills within the inventory boundaries. These tools can also be used in cases where a manufacturing facility's process waste is being disposed in a municipal solid waste landfill and the company is interested in estimating the facility's contribution to the municipal landfill emissions. The reporting format, however, has been prepared assuming that only the emissions from company-owned landfills will be reported.

As is the case with most widely accepted protocols, only CH₄ emissions are addressed in these tools because the CO₂ from landfills is composed of biomass carbon (not counted as a greenhouse gas) and the N₂O emissions are assumed to be negligible.

An emission factor for landfilled waste is presented in Table 1 of the main body of this report. This factor is based on a number of conservative assumptions and, in most cases, is expected to be higher than the actual emissions attributable to landfilled wood products plant waste. The emission factor can be useful, however, in deciding whether landfill emissions are material to the results of the inventory. For preparing an estimate to use in the inventory results, however, these calculation tools recommend the methods described herein, all of which are contained in the Excel[®] workbook that accompanies this report.

1.1 Using Data from Landfill Gas Collection Systems

In some cases, company landfills are capped with low permeability cover material and the landfill gas is collected. In many of these situations, the amounts of methane collected and destroyed can be estimated from site-specific data. IPCC recommends that this information be used by subtracting the amounts of methane destroyed from the amounts of methane that the company estimates are generated by the landfill. The problem with this approach is that, because of the large uncertainties in estimating methane generation, the amounts burned (which are measured) could easily be greater than the amounts generated (which are estimated), resulting in a negative release. It is equally possible that the comparison of estimated generation rates to measured collection rates could suggest impossibly low collection efficiencies, due only to the uncertainties in estimating methane generation.

An alternative approach is available to companies that measure the amounts of methane captured in the collection system. The alternative approach is to estimate the collection efficiency of the collection system and back-calculate the amounts of methane generated. For instance, if a manufacturing plant with a capped landfill has determined that its collection

system collects 90 tons of methane per year and estimates that the collection efficiency is 90%, it means that 100 tons of methane were generated.

The problem with this approach is that the effectiveness of landfill gas collection systems is variable and uncertain. Reported collection efficiencies range from 60 to 85% (USEPA 1998). This variability and uncertainty has caused IPCC to take the position that “the use of undocumented estimates of landfill gas recovery potential is not appropriate, as such estimates tend to overestimate the amount of recovery” (IPCC 2000). Nonetheless, this approach is built around a measured value—the amount of gas collected. Thus, it is reasonable to expect that in some cases it may yield more accurate estimates than IPCC’s default methodology. This is especially true for wood products plant landfills because of the limited data for deriving the parameter values needed to use IPCC’s default methodology on wood products industry wastes.

Therefore, these calculation tools recommend that where landfills are covered with low permeability caps and equipped with landfill gas collection systems constructed and operated to normal standards, the methane generation rates should be back calculated from measurements of the amounts of methane collected and estimates of collection efficiency. A default collection efficiency of 75% has been used by some authorities and is recommended here, unless site-specific collection efficiency data are available (USEPA 1998).

These calculation tools also assume that all of the methane that is captured and burned is converted to biomass CO₂ and therefore does not have to be included in the inventory.

Using these default values and assumptions, estimates of methane generation can be developed using equation 1.

$$CH_4 (m^3/y) \text{ released to the atmosphere} = [(REC / FRCOLL) * (1 - FRCOLL) * FRMETH * (1 - OX)] + [REC * FRMETH * (1 - FRBURN)] \quad (Eq.1)$$

where: *REC* = amount of landfill gas collected, determined on a site-specific basis, m³/y

FRCOLL = fraction of generated landfill gas that is collected, default is 0.75

FRMETH = fraction of methane in landfill gas, default is 0.5

OX = fraction of methane oxidized in the surface layer of the landfill, default is 0.1

FRBURN = fraction of collected methane that is burned, site-specific determination

1.2 Estimating Landfill Methane Emissions at Landfills without Gas Collection Data

1.2.1 The Simplified First Order Decay Approach

Where the approach described in Section 1.1 cannot be used, it is recommended that companies employ the first order decay model approach for estimating landfill gas emissions using parameter values derived for wood products industry landfills. This approach is the default method recommended by IPCC and is used by a number of national authorities (IPCC 2000). It can be used to estimate CH₄ emissions from active and inactive landfills.

In cases where the annual deposits are (or are assumed to be) constant IPCC’s default method reduces to two equations. This approach should be adequate unless the amounts or types of

waste being landfilled have changed significantly from year to year, or the landfill design or operation have been changed in a way that would significantly impact methane generation or release (e.g., a gas collection system is installed).

$$CH_4 (m^3/y) \text{ generated from all waste in the landfill} = R L_0 (e^{-kC} - e^{-kT}) \quad (Eq.2)$$

where: R = average amount of waste sent to landfill per year, Mg/y

L_0 = ultimate methane generation potential, m^3 /Mg waste

k = methane generation rate constant, 1/y

C = time since landfill stopped receiving waste, y

T = years since landfill opened, y

(Note: R and L_0 can be in units of wet weight, dry weight, degradable organic carbon, or other units but the units for R and L_0 must be the same.)

Not all methane that is generated is subsequently released to the atmosphere. To estimate atmospheric releases, use the result from equation 2 in equation 3. For landfills with modern gas collection and combustion systems but no measurements of quantities of gas collected, the amount of methane recovered can be assumed to be 75% of that generated (USEPA 1998).

$$CH_4 (m^3/y) \text{ released} = [(CH_4 \text{ generated} - CH_4 \text{ recovered}) * (1 - OX)] + [CH_4 \text{ recovered} * (1 - FRBURN)] \quad (Eq.3)$$

where: CH_4 generated = from equation 2

CH_4 recovered = amount of methane collected, site-specific determination

OX = fraction oxidized in the surface layer of the landfill before escaping, usually assumed to be 0.1

$FRBURN$ = fraction of collected methane that is burned, site-specific determination

If the amounts being landfilled have changed significantly or if the landfill design has been altered so that some of the parameter values would have changed substantially, a more involved approach may be needed. To deal with these more complicated situations, many protocols recommend modeling the gas generated annually from each year's deposits and then summing the amounts that are predicted to occur in the current year. This more detailed analysis is described in Section 1.2.2.

A number of sources for the parameter values L_0 and k needed in these equations are shown. Unfortunately, the values vary considerably from one protocol to the next and the values are based on very few data.

1.2.2 Detailed First Order Decay Approach

To allow year-to-year variations in the amounts of waste sent to landfill, IPCC suggests a variation of this approach. Using this variation, starting in year one, you calculate how much methane will be generated in each subsequent year by waste deposited in that year using equations 4 and 5.

$$CH_4 \text{ generated in a given year by waste deposited in an earlier year} \\ (m^3/y = k R_y L_0 (e^{-k[T-Y]})) \quad (Eq.4)$$

where: k = methane generation rate constant, 1/yr

R_y = the amount of waste sent to landfill in year Y , Mg/yr

L_0 = ultimate methane generation potential, m^3 /Mg waste

T = year for which emissions are being estimated given in terms of years since the landfill opened

Y = year after landfill opened that waste was disposed

Thus $(T-Y)$ is equal to the number of years the waste has been in place prior to the year for which emissions are being estimated.

$$CH_4 (m^3/y) \text{ released} = [(CH_4 \text{ generated} - CH_4 \text{ recovered}) * (1 - OX)] + \\ [CH_4 \text{ recovered} * (1 - FRBURN)] \quad (Eq.5)$$

where: $CH_4 \text{ generated}$ = from equation 4

$CH_4 \text{ recovered}$ = amount of methane collected, site-specific determination

OX = fraction oxidized in the surface layer of the landfill before escaping, usually assumed to be 0.1

$FRBURN$ = fraction of collected methane that is burned, site-specific determination

To perform the calculations, estimate how much waste was deposited every year since the landfill was opened. IPCC indicates that for very old landfills, it is possible to limit the retrospective period to one starting at least three waste degradation half-lives before the current year. Given the slow degradation observed in many wood products industry wastes, 25 years is probably the minimum that would satisfy this criterion. For each year's deposit, estimate for that year and each following year the amount of methane released. In subsequent years, the amount of methane released is the sum of the amounts estimated from each prior year's deposits that were projected to occur in that year.

The calculations work like this. In year 1 you deposit amount A and estimate that in years 1, 2, 3, ... it will release X_1 , X_2 , X_3 , ... tons of methane, respectively. The reported emissions for year one are X_1 tons of methane. In year 2 you deposit amount B and estimate that in years 2, 3, 4, ... it will release Y_2 , Y_3 , Y_4 , ... tons of methane, respectively. The emissions reported for year 2 are X_2 plus Y_2 tons methane. In year 3, you deposit amount C and estimate that in years 3, 4, 5, ... it will release Z_3 , Z_4 , Z_5 , ... tons of methane, respectively. The reported emissions for year 3 are X_3 plus Y_3 plus Z_3 tons of methane. This process repeats itself every year.

The values for k and L_0 are the same as those used in the simplified first order approach.

1.2.3 First Order Methane Generation Rate Constant, k

Even for municipal waste landfills, there is large uncertainty about the proper first order rate constant. The correct value for wood products industry landfills is even more uncertain. The guidance offered by the sources reviewed in this study is summarized here.

- IPCC – k varies from 0.005 to 0.4 per year, with a default of 0.05/yr for MSW (IPCC 1997c)
- UK – k varies from 0.05/yr for slowly degrading waste to 0.185/yr for rapidly degrading waste (AEA Technology 2001)
- Sweden – k equals 0.092/yr for all landfills (Swedish Environmental Protection Agency 2001)
- Canada – k for wood waste landfills equals 0.01/yr, and varies by province for MSW landfills (Environment Canada 2002)
- EPA – k equals 0.04/yr for areas receiving at least 25 inches (63.5 cm) of precipitation and 0.02/yr for drier areas (for MSW landfills) (USEPA 1998)

1.2.4 *Ultimate Methane Generation Potential, L_0*

Again, there is a great deal of variability in the values being used for L_0 . The parameter values shown are for MSW unless otherwise indicated. It is also important to note that L_0 can be expressed as wet weight, dry weight, and a number of other ways. Any form is acceptable, but the units of L_0 and R (the amount of waste disposed) must be the same. Values given for municipal solid waste are often for wet waste as disposed.

- IPCC – The sources cited by IPCC indicate that L_0 can vary from less than 100 to over 200 m³/Mg. An equation is provided for calculating a site-specific L_0 (IPCC 1997c):

$$L_0 = (\text{DOC, fraction degradable organic carbon in waste}) \times (\text{DOC}_f, \text{fraction of DOC that degrades into landfill gas}) \times (16/12, \text{to convert carbon to methane}) \times (F, \text{fraction CH}_4 \text{ in gas from a managed landfill, default value is 0.5}) \times (\text{MCF, amount of methane in landfill gas relative to a managed landfill})$$

For MSW landfill default values, IPCC recommends (IPCC 1997c, 2000):

DOC – the default values for different countries range from 0.08 to 0.21, but site-specific determinations are recommended

DOC_f – the default range if the DOC includes lignin is 0.5 to 0.6

F – default is 0.5

MCF - 1.0 for modern managed landfills, 0.4 for shallow unmanaged landfills (less than 5 m deep), and 0.8 for deeper unmanaged landfills

- UK – The IPCC equation is used to calculate L_0 . The DOC for different types of waste was determined from a national study. DOC_f was assumed to be 0.6. F was usually 0.5, but 0.3 was used for old, shallow sites. MCF was assumed to be 1.0 (AEA Technology 2001).
- Sweden – Sweden uses an L_0 of 45 kg CH₄/ton of waste specifically for pulp and paper mill sludge landfills. This is equivalent to 63 m³/Mg (Swedish Environmental Protection Agency 2001).

- Finland – Although Finland does not use the first order model approach for landfill methane, the approach it uses still requires it to estimate L_0 . Finland uses the IPCC equation for L_0 , and these values for the variables in the equation (Technical Research Center of Finland 2001):

DOC = 0.4 for paper and cardboard, wet weight basis

= 0.3 for wood and bark, wet weight basis

= 0.1 for deinking waste, wet waste basis (definition is uncertain since deinking sludge is listed separately)

= 0.45 forest industry sludge-unspecified, dry weight basis (assumed 30% solids)

= 0.3 deinking sludge, dry weight basis (assumed 30% solids)

= 0.3 forest industry fiber sludge, dry weight basis (assumed 30% solids)

DOC_f = 0.5 (reflects low temperature and less-than-optimal conditions for decomposition in Finnish landfills)

MCF = 0.7 (assumes that half of waste goes to small landfills with MCF=0.4 and the rest goes to large landfills with MCF=1)

F = 0.5

Putting these together using a range in DOC of 0.3 to 0.45 for wood products industry wastes on a dry weight basis and assuming an MCF of 1, the calculated range for L_0 is 0.1 to 0.15 kg CH₄/kg dry waste or 140 to 210 m³/Mg.

- Canada – To calculate the methane potential for wood waste landfills, Canada uses an L_0 of 118 kg CH₄/ton wood waste, which converts to 165 m³/Mg. For MSW landfills, Canada has used an L_0 value of 165 kg CH₄/ton for the years 1941 through to 1989. For subsequent years, a value for L_0 of 117 kg CH₄/ton is recommended for MSW landfills (Environment Canada 2002).
- United States – EPA's compilation of emission factors (AP-42) indicates that a value of 100 m³/Mg is recommended as the default factor for most MSW landfills (USEPA 1998).

1.2.5 Recommended Default Values for k and L_0

For situations where wastewater treatment sludge is a major constituent of the waste, reasonable values for the rate constant, k , fall in the range of 0.01 to 0.1/yr, while those for L_0 fall between 50 and 200 m³/Mg. NCASI is conducting research that should narrow these ranges. Initial indications are that the amounts of gas generated in forest products industry landfills are less than would be predicted using parameter values developed for municipal solid waste (NCASI 1999). With this knowledge, it is recommended that until the current research is completed, and unless companies have country-specific or site-specific factors that are more appropriate for their wastes, companies use the parameter values shown in Table F1.

Table F1. Recommended Default Values for k and L₀ for Estimating Wood Products Industry Landfill Methane Emissions

Parameter	Default Value
k	0.03 y ⁻¹
L ₀	100 m ³ /Mg dry weight of waste

2.0 RECOMMENDED APPROACH FOR ESTIMATING CH₄ EMISSIONS FROM THE ANAEROBIC TREATMENT OF WASTEWATER OR SLUDGE **[Note: Most of Section 2.0 is identical to Section 13 in the Calculation Tools Report]**

Most existing GHG protocols address GHG emissions only from anaerobic treatment and digestion processes. Therefore, these calculation tools have been developed assuming that emissions from other types of wastewater and sludge treatment processes are negligible. Although aerobic and facultative treatment systems may have zones with depleted dissolved oxygen, methane generation rates in aerated stabilization basins, activated sludge systems, and their associated retention ponds would be expected to be much less than in anaerobic systems. In any event, due to lack of data, it is not possible to reasonably estimate emissions from aerobic and facultative treatment operations.

Even for anaerobic systems, only CH₄ emissions need to be estimated because (a) the CO₂ emitted from wastewater and sludge treatment operations contains biomass carbon which is not included in most GHG protocols; and (b) other protocols assume that N₂O emissions, if any, occur after the wastewater is discharged.

2.1 Anaerobic Treatment Operations where Off-Gases are Captured

In many cases, anaerobic treatment systems are covered and the gases are collected and burned. One of the purposes of these collection systems is the prevention of odors, and to accomplish this objective, the systems must be highly efficient. For purposes of a GHG inventory it is reasonable to assume, therefore, that where methane emissions from anaerobic treatment operations are captured and burned, the collection and destruction is complete and no methane is emitted. If circumstances at a wood products plant suggest that non-trivial amounts of methane are escaping collection, the plant may need to undertake efforts to account for these releases, but such circumstances are expected to be unusual at plants that collect and burn these gases.

Of course, if the gases are collected but released to the atmosphere rather than being burned, they should be included in the inventory.

2.2 Anaerobic Treatment Operations where Off-Gases are Released to the Atmosphere

Where off-gases from anaerobic treatment operations are not collected and burned, it is necessary to estimate the releases of methane to the atmosphere. In some cases, for instance where the gases are released through a vent in a covered vessel, the releases can be measured directly. In most other cases, they must be estimated.

These calculation tools suggest the use of the IPCC default methodology as described in the May 2000 Good Practices document and shown in equation 6 (IPCC 2000). Although the IPCC document allows the equation to be applied to systems that are not completely anaerobic (by multiplying the result by an arbitrary adjustment factor of less than one), there are no data currently available to support the selection of the adjustment factor. It is recommended, therefore, that methane emissions only be estimated from anaerobic treatment or sludge digestion systems until such time as factors for other types of systems are available.

$$\text{Anaerobic Treatment Plant Methane Emissions (kg/y)} = (OC \times EF) - B \quad (\text{Eq. 6})$$

where: *OC* = BOD or COD of the feed to the anaerobic system, kg/year

EF = emission factor, default values = 0.25 kg CH₄/kg COD in the feed or 0.6 kg CH₄/kg BOD in the feed (or another BOD-based factor developed by multiplying the COD-based factor of 0.25 kg CH₄/kg COD by the site-specific COD/BOD ratio)

B = methane captured and burned, kg CH₄/year, determined on a site-specific basis

If the solids are handled separately, emissions from sludge digestion would be calculated using equation 7. In cases where sludge is burned, it is included in the calculations for GHG emissions from biomass burning, discussed elsewhere.

$$\text{Anaerobic Sludge Digestion Plant Methane Emissions (kg/y)} = (OCs \times EFs) - B \quad (\text{Eq. 7})$$

where: *OCs* = organic content of the sludge

EFs = emission factor, in units consistent with *OCs*; IPCC's default value is 0.25 kg CH₄/kg COD in the sludge feed

B = methane captured and burned, kg CH₄/yr, determined on a site-specific basis.

Under most protocols, emissions of N₂O from wastewater are assumed to take place after wastewater is discharged into receiving waters. These emissions, therefore, are not addressed in these tools.

3.0 OVERVIEW OF EXISTING APPROACHES

3.1 IPCC – Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories (IPCC 1997c) and Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories (IPCC 2000)

Note: In the following discussion, some of the symbols used are different than those used in the IPCC documents. This has been done in an attempt to eliminate potential confusion among variables having similar symbols in the IPCC documents.

3.1.1 Landfills – The All-in-One-Year Approach

The IPCC default methodology for estimating methane emissions from landfills is limited to municipal solid waste landfills. Chapter 6 of the 1996 IPCC Guidelines Reference Manual (IPCC 1997c) and Chapter 5 of the May 2000 Good Practices document (IPCC 2000) outline two general approaches for estimating landfill emissions. The first approach assumes that all organic matter degrades in the year it is placed in the landfill, while the second approach uses

a first order model to estimate the amounts released over time. The Good Practices document indicates that the first order decay approach should be used where possible (IPCC 2000).

The all-in-one-year approach starts with an estimate of the “degradable organic carbon” (DOC) content of the waste going to landfill. IPCC provides the default values for certain large volume materials shown in Table F2.

Table F2. Default DOC Values for Major Waste Streams from IPCC’s 1996 Revised Methodology (values are for “wet or fresh” materials in municipal solid waste)

Waste Stream	Percent Degradable Organic Carbon, % by weight
Paper and textiles	40
Garden and park wastes and other non-food organic putrescibles	17
Food waste	15
Wood and straw waste (excluding lignin)	30

Of the amount of carbon that is degradable organic carbon, only a fraction is converted into landfill gas. This fraction is given the symbol DOC_f . IPCC’s 1996 Guidance relies on a simple model to generate a default value of 0.77 for DOC_f , but IPCC’s May 2000 Good Practice Guidance and Uncertainty Management document indicates that this appears to be too high unless lignin carbon is excluded from the DOC value. The May 2000 document goes on to say that a “good practice” default value of 0.5 to 0.6 should be used for DOC_f in cases where lignin is included in the DOC unless better site-specific data are available (IPCC 2000).

IPCC then applies a factor, the methane correction factor or MCF, which is intended to account for the fact that landfill design and operation can influence the tendency of degradable carbon to decompose into carbon dioxide rather than methane. The MCF is simply a measure of the relative methane generation potential of unmanaged landfills compared to managed landfills. A landfill is “managed” if it involves controlled placement of waste, a degree of control over access, and at least one of the following: cover material, mechanical compacting, or leveling of waste. Managed landfills are used as the baseline condition, so the MCF is 1.0 for such landfills. The MCF for shallow, unmanaged landfills (less than 5 m deep) is 0.4, while the factor for deeper, unmanaged landfills is 0.8. At a managed landfill, the default assumption is that methane comprises 50% of the landfill gas. The MCFs modify this assumption for unmanaged landfills; i.e., methane comprises 40% of the gas from deep, unmanaged landfills ($0.8 \times 50\%$) and 20% of the gas from shallow, unmanaged landfills ($0.4 \times 50\%$).

Gas is trapped and burned at many landfills, converting the carbon to biomass- CO_2 . Methane generated within a landfill may also be converted to biomass- CO_2 as it migrates through the surface of the landfill. Because the CO_2 formed from landfill methane is biomass carbon, it is not included in IPCC emission inventories. In IPCC’s words, “[d]ecomposition of organic

material derived from biomass sources (e.g., crops, forests) which are regrown on an annual basis is the primary source of CO₂ released from waste. Hence, these CO₂ emissions are not treated as net emissions from waste in the IPCC Methodology. If biomass raw materials are not being sustainably produced, the net CO₂ release should be calculated and reported under the Agriculture and Land-Use Change and Forestry Chapters” (IPCC 1997c).

Overall, therefore, the IPCC all-in-one-year approach involves these calculations:

$$\text{Methane generated} = (\text{amount of waste sent to landfill}) \times \text{DOC} \times \text{DOC}_f \times 16/12 \times 0.5 \times \text{MCF} \quad (\text{Eq.8})$$

where: *DOC* = fraction degradable organic carbon in waste (based on the same units as used to measure the amount of waste sent to landfill)

DOC_f = fraction of DOC that degrades into landfill gas

16/12 = conversion factor from carbon to methane

0.5 = fraction methane in gas from a managed landfill, default value

MCF = amount of methane in landfill gas relative to a managed landfill (managed landfill *MCF* = 1)

$$\text{Methane released} = (\text{Methane generated} - \text{REC}) \times (1 - \text{OX}) \quad (\text{Eq.9})$$

where: *REC* = amount of methane converted to CO₂ by burning

OX = fraction of methane converted to CO₂ by oxidation in the landfill cover (default value is zero but IPCC’s May 2000 Good Practices document indicates that a value of 0.1 can be used for well managed landfills in industrialized countries)

3.1.2 Landfills – The First Order Decay Approach

IPCC suggests two approaches for modeling methane releases from landfills over time. The first uses the average waste acceptance rate over the life of the landfill (see Section 1.2.1 of this annex for a description), while the second considers each year’s waste separately (see Section 1.2.2 of this annex for a description) (IPCC 1997c).

3.1.3 Wastewater Treatment and Anaerobic Sludge Digestion

In aerobic treatment plants, most of the organic matter in wastewaters is converted to either biological sludge or carbon dioxide. Because the carbon originated in biomass, the CO₂ emitted from wastewater treatment is not included in GHG inventories. Methane and nitrous oxide, however, can also be released during wastewater treatment. Methane, in particular, is an important emission from anaerobic wastewater treatment and sludge digestion processes. Methane and nitrous oxide are usually included in GHG inventories.

The Waste section of the 1996 Revised Guidelines contains a method for estimating N₂O emissions from “human sewage” (IPCC 1997c, page 6.28). That discussion directs the reader to the Agriculture section of the Manual for more information. In that section IPCC indicates that three studies have examined nitrous oxide emissions from operating wastewater treatment facilities (IPCC 1997c, page 4.110). All of the studies reported low N₂O emissions. Thus, in IPCC’s methodology “N₂O associated with sewage treatment and

land disposal is assumed to be negligible,” and it is further assumed that “all sewage nitrogen enters rivers and/or estuaries” where a portion of it is converted into N₂O (IPCC 1997c). In summary, IPCC’s guidance contains methods for estimating N₂O released from human sewage once it is discharged, but assumes that N₂O emissions from treatment plants are negligible. There is no discussion of N₂O emissions from wood products or other industrial wastewater treatment plants.

Methane from wastewater treatment, however, receives much greater attention in IPCC’s guidance documents. A diagram in the IPCC Good Practice document shows which types of treatment processes have “the potential for CH₄ emissions” (IPCC 2000, page 5.17). The figure indicates that all aerobic treatment processes are outside of the scope of IPCC’s guidelines due to the low potential for methane generation. The guidelines focus on anaerobic wastewater treatment and anaerobic sludge digestion.

The Reference Manual of IPCC’s 1996 Revised Guidelines contains a discussion of pulp and paper industry waste treatment operations (IPCC 1997c, page 6.16):

Assessment of CH₄ production potential from industrial wastewater streams is based on the concentration of degradable organic matter in the wastewater, the volume of wastewater, and the *propensity of the industry to treat their wastewater in anaerobic lagoons*. [emphasis added]

Using these criteria, IPCC cites work suggesting that paper and pulp manufacturers are among the most likely to generate methane in wastewater treatment (IPCC 1997c).

Both the paper and pulp industry and the meat and poultry processing industries produce large volumes of wastewater that contain high levels of degradable organics. Additionally, both industries utilize large facilities that often have their own wastewater handling systems. The meat and poultry processing facilities commonly employ anaerobic lagoons to treat their wastewater, while the paper and pulp industry is known to use lagoons.

IPCC’s approach for estimating methane from wastewater treatment or sludge digestion is similar to the all-in-one-year method used for estimating methane emissions from landfills. Emissions are calculated using equation 10:

$$\text{Methane emissions} = (\text{TOW or TOS}) \times B_0 \times \text{MCF} \quad (\text{eq.10})$$

where: TOW or TOS = measure of organic content of anaerobically treated wastewater or sludge

B_0 = CH₄ per unit of organic matter, in units consistent with TOW or TOS

MCF = fraction of methane not recovered or flared, varies from 0 to 1 depending on the treatment unit

First, the amount of degradable substrate being fed to the treatment unit is determined. The total organic (chemical oxygen demand, COD) in wastewater is given the symbol TOW while the total organic in sludge is given the symbol TOS. The IPCC reference manual contains some limited data that can be used to estimate pulp and paper mill wastewater COD,

but they are not included in this report because data available to individual companies are expected to be of far greater quality (IPCC 1997c).

After dividing the untreated wastewater COD into TOW and TOS, the two streams are kept separate in subsequent calculations. Landfill calculations for sludge are shown in Section 1.2 of this annex, while emissions from sludge digestion would be calculated using equation 10. In cases where sludge is burned, it is included in the calculations for GHG emissions from biomass burning, discussed elsewhere.

For industrial wastewaters, the maximum methane producing capacity is given the symbol B_0 and is expressed in kg CH₄/kg COD. IPCC's 1996 Revised Guidelines give a default value for B_0 of 0.25 kg CH₄/kg COD for wastewater and sludge. A footnote in the IPCC guidelines explains that because the degradable organic matter in COD is the same material that is measured as degradable BOD, the factor B_0 will be 0.25 kg CH₄/kg COD or BOD. This is approximately true if the factors are based on BOD or COD *removed*, but the Guidelines do not specify this, saying only that TOW and TOS are the total organic contents in industrial wastewaters and sludges, respectively (IPCC 1997c). The IPCC Good Practice document changes the 1996 Guidelines with this explanation (IPCC 2000, page 5.17):

Note that degradable carbon in organic waste can be measure in terms of either BOD or COD. For typical domestic raw sewage, COD (mg/l) is 2 to 2.5 times higher than BOD (mg/l). Therefore, it is important to use emission factors that are consistent with the measure of degradable carbon being used. The IPCC Guidelines provide only one default value of B_0 that has to be applied to both COD and BOD. This is not consistent with the observed differences between BOD and COD levels in raw sewage. Given the differences in the amount of BOD and COD in wastewater this can result in estimates of different emissions levels from the same amount of wastewater depending on which measure is used. To ensure that the resulting emission estimate from a given amount of wastewater is the same regardless of the measure of organic carbon used, the COD-based value of B_0 should be converted into a BOD-based value via up-scaling with a default factor of 2.5. Thus, it is *good practice* to use a default value of 0.25 kg CH₄/kg COD or a default value of 0.6 kg CH₄/kg BOD.

The important point is that the basis for the factors must match the measure of organic content of the waste. In particular, one needs to know whether the factors are for BOD or COD and whether they are based on the organic content of the untreated wastewater or the organic content removed during treatment.

A methane conversion factor (MCF) is again used to represent the methane generation potential relative to a reference system. In this case, there are two reference systems. The MCF for completely aerobic systems is 0.0, while the MCF for completely anaerobic systems is 1.0. Although the Reference Manual shows default MCFs for various countries, IPCC suggests that experts be consulted in determining appropriate values for MCF (IPCC 1997c). In this review, no published values of MCF for aerobic or facultative treatment systems were found.

3.2 Canada – Guide to Entity- and Facility-Based Reporting, Canada’s Climate Change Voluntary Challenge and Registry (VCR 2003) and Canada’s Greenhouse Gas Inventory 1990-2000 (Environment Canada 2002)

The VCR guidance does not specifically include emissions from waste management activities. These emissions are included, however, in Canada’s Greenhouse Gas Inventory, 1990-2000 (Environment Canada 2002).

Canada does not count CO₂ produced by the decomposition of biomass carbon. Estimates are made for CH₄ and N₂O emissions, however (Environment Canada 2002).

3.2.1 *Landfills*

Because the character of Canada’s landfills has been changing over time, Canada uses the Scholl Canyon model (first order decay model) for estimating methane emissions from landfills. This allows varying amounts of waste to be deposited every year and also allows the decay rate to vary according to management practices and other factors. This is one of the options described in the IPCC 1996 Revised Guidelines and the May 2000 IPCC Good Practices document. The description herein highlights only those aspects of the Canadian approach that either involve Canada-specific parameter values or represent departures from the IPCC approach (Environment Canada 2002).

Because of the large size of the forest products industry in Canada, the government developed separate estimates of methane emissions from wood waste landfills. After evaluating the recommendations developed by Canadian experts for k values to model municipal solid waste (MSW) landfills, the government decided to use the lowest k value for MSW in the major forest industry provinces to estimate emissions from wood waste landfills. This k was 0.01/yr. The Canadian government considered the degradable carbon content of wood waste and assumed that wood waste landfill gas would consist of 50% methane to calculate a methane generation potential, L₀, for wood waste of 118 kg CH₄/tonne of wood waste (Environment Canada 2002).

3.2.2 *Wastewater Treatment and Sludge Digestion*

Canada only estimated GHG emissions from municipal wastewater treatment due to lack of data on treatment of industrial wastewater (Environment Canada 2002).

Methane emissions from aerobic systems were assumed to be negligible, an assumption consistent with IPCC’s guidance. Emissions from anaerobic systems were estimated using an approach developed by Ortech International for Environment Canada in 1994. Using this approach, it was estimated that 4.015 kg CH₄/person/year could potentially be emitted from wastewater treated anaerobically (Environment Canada 2002). This factor was multiplied by the number of persons in each province and the fraction of the wastewater treated anaerobically in each province to estimate methane emissions from the anaerobic treatment of municipal wastewater.

Canada used the IPCC default methodology for estimating N₂O emissions from human sewage. The IPCC methodology assumes that (a) negligible amounts of N₂O are released

during treatment; and (b) all of the nitrogen in untreated human sewage is discharged to rivers or estuaries, where a portion of the nitrogen is converted to N₂O (Environment Canada 2002).

3.3 United States – EPA Inventory of US Greenhouse Gas Emissions and Sinks: 1990-1999 (USEPA 2001a) and Anthropogenic Methane Emissions in the United States: Estimates for 1990, Report to Congress (USEPA 1993)

3.3.1 Landfills

EPA's analysis of GHG emissions from landfills is focused on methane from municipal solid waste landfills, although estimates are also given for industrial landfill emissions of methane. This description of the methodology is taken from EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1999 (USEPA 2001a, page 7-4):

Based on available information, methane emissions from landfills were estimated to equal the methane produced from municipal landfills, minus the methane recovered and combusted, minus the methane oxidized before being released into the atmosphere, plus the methane produced by industrial landfills.

The methodology for estimating CH₄ emissions from municipal landfills is based on a model that updates the population of U.S. landfills each year. This model is based on the pattern of actual waste disposal by each individual landfill surveyed by the EPA's Office of Solid Waste in 1987. A second model was employed to estimate emissions from the landfill population. [This model is described in USEPA 1993.] For each landfill in the data set, the amount of waste-in-place contributing to methane generation was estimated using its year of opening, its waste acceptance rate, year of closure, and design capacity. Data on national waste disposed in landfills each year was apportioned by landfill. Emissions from municipal landfills were then estimated by multiplying the quantity of waste contributing to emissions by emission factors....

The estimated landfill gas recovered per year was based on updated data collected from vendors of flaring equipment, and a database compiled by the EPA's Landfill Methane Outreach Program (LMOP)....

Emissions from industrial landfills were assumed to be equal to 7 percent of the total methane emissions from municipal landfills. The amount of methane oxidized was assumed to be 10 percent of the methane generated. To calculate net methane emissions, both methane recovered and methane oxidized were subtracted from methane generated at municipal and industrial landfills.

The "model" described in Anthropogenic Methane Emissions in the United States: Estimates for 1990, Report to Congress, is a two parameter model for MSW landfills (USEPA 1993). It is based on an empirical analysis of gas generation data from more than 85 US MSW landfills and estimates methane generation based on the mass of waste in place and the ambient rainfall.

EPA also has a model, however, that is equivalent to the first order decay model suggested by IPCC. EPA's first order model is described in its compilation of emission factors, AP-42 (USEPA 1998). EPA calls its model the Landfill Air Emissions Estimation Model (LAEEM). NCASI has reviewed EPA's normal approach for estimating methane emissions from landfills and the results are reported in NCASI Technical Bulletin No. 790 (NCASI 1999). The material herein is taken primarily from that source.

LAEEM is a PC-based automated estimation tool, operating in a Windows™ environment, for calculating uncontrolled air emissions from municipal solid waste (MSW) landfills, available from the EPA Office of Air Quality Planning and Standards.

LAEEM incorporates the Scholl Canyon model, a first order, single stage model identical to IPCC's. Kinetic rate coefficients were empirically adjusted to reflect changes in refuse moisture content and other landfill conditions. The Scholl Canyon model assumes that the gas production rate is at its peak upon initial waste placement and that anaerobic conditions are established immediately. Gas production is then assumed to decrease exponentially as a first order decay. The model allows for division of the landfill into modules (annual refuse accumulations) to account for different ages of refuse accumulated over time.

A default first order rate constant for methane generation (k) of 0.04/yr is recommended for areas receiving 25 inches or more of rain per year, while a value of 0.02/yr is recommended for drier areas. A default value for methane generation potential, L_0 , of 100 m³ methane/Mg waste is recommended (USEPA 1998). An examination of the source of these recommendations by NCASI led to the conclusion that EPA's default values (derived from studies of MSW landfills) are probably too high for wood products industry landfills (NCASI 1999).

NCASI is generating industry-specific values for L_0 and k in both the laboratory and the field. Studies to determine values for L_0 are underway in the laboratory for five paper industry sludges and are nearing completion. Because the rate constant is sensitive to field conditions such as temperature and moisture, NCASI has initiated field experiments to investigate the rate constant that can be expected under real world conditions. Results of these experiments for rate constants will be available in two to four years. Preliminary examination of the data generated in the studies supports the conclusions drawn in Technical Bulletin No. 790 (NCASI 1999).

3.3.2 Wastewater Treatment and Anaerobic Sludge Digestion

EPA indicates that it used the IPCC methodology for estimating methane emissions from wastewater treatment. This involved estimating the amount of wastewater organic matter produced and multiplying that amount by an emission factor. EPA estimated methane emissions only from anaerobic treatment operations, which were assumed to be handling 15% of the domestic wastewater BOD generated in the US (USEPA 2001a).

The emission factor used by EPA is 0.6 kg CH₄/kg BOD₅. EPA cites IPCC's May 2000 Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories as the source of that emission factor.

EPA also developed a separate estimate of methane emissions from pulp and paper industry wastewater treatment operations. The estimate was developed by assuming that 1% of the pulp and paper mill wastewater treated in mill-owned treatment plants is treated anaerobically in systems that allow the methane to escape to the atmosphere. The emission factor was the same one EPA used for municipal wastewater treatment, 0.6 kg CH₄/kg BOD₅. For wood products plants, however, EPA estimated methane emissions by multiplying the emission factor by the amounts of BOD removed in treatment. The IPCC factor of 0.6 kg CH₄/kg BOD is based, however, on organic matter in untreated wastewater. Because of the high removal efficiencies for BOD in wastewater treatment, the discrepancy is relatively unimportant (USEPA 2001).

3.4 WRI/WBCSD – The Greenhouse Gas Protocol, October 2001 (WRI 2001a)

The WRI/WBCSD Protocol divides GHG emissions from waste management into those from company-owned sources (included in Scope 1 of the WRI/WBCSD Protocol) and those from sources owned by other entities (included in Scope 3).

ANNEX G

CARBON DIOXIDE FROM BIOMASS COMBUSTION

1.0 ESTIMATES OF CO₂ EMISSIONS FROM BIOMASS COMBUSTION

Wood products plants generate a significant portion of their energy needs from biomass fuels recovered from the industry's waste and process streams. Energy-rich biomass—derived from wood chips, bark, shavings/trimmings, and sawdust recovered from the harvesting and manufacturing processes—is atmospheric carbon dioxide sequestered by trees during growth and transformed into organic carbon substances. When these biomass fuels are burned, the CO₂ emitted during the manufacturing and combustion processes is the atmospheric carbon dioxide that was sequestered during growth of the tree; hence, there is no net contribution to the atmospheric CO₂ level. This carbon cycle is a closed loop. New tree growth keeps absorbing atmospheric carbon dioxide and maintains the cycle.

Any increases or decreases in the amount of carbon sequestered by the forests are accounted for in the comprehensive forest accounting system. This is the approach generally prescribed for national inventories by the United Nations Framework Convention on Climate Change. Most international protocols, including that of the Intergovernmental Panel on Climate Change (IPCC), have adopted the convention set out by the United Nations. The IPCC has stated that emissions from biomass do not add to atmospheric concentrations of carbon dioxide (IPCC 1997a,c).

1.1 Estimated Biomass Emissions

The information on biomass emissions is being supplied:

- to ensure that readers understand the entity's overall energy profile in terms of both greenhouse gas emissions and non-greenhouse gas emissions
- to provide awareness and understanding of how biomass fuels are generated and used in the manufacture of wood products

Table H1 can be used to estimate emissions of CO₂ from biomass combustion and record the results.

Note that this information is in conformance with the general greenhouse gas protocol designed by the World Resources Institute and the World Business Council for Sustainable Development (WRI 2001a). Users of these calculation tools may elect to modify the format and type of information presented based on specific facility or company needs.

Table G1. Estimating Carbon Dioxide from Combustion of Wood, Bark, and other Biomass Fuels

Source Description	Fuel Type	Step 1		Step 2		Step 3	
		A	B	C	D	E	F
		Quantity of fuel burned	Unit used to measure quantity of fuel use [Note: Be careful not to mix HHVs and LHV.s.]	Biomass-derived CO ₂ emission factor: [default value is: solid biomass: 241* lb CO ₂ /MMBtu HHV]	Unit of biomass-derived CO ₂ emission factor	Biomass-derived CO ₂ emissions in lb CO ₂ /yr	Biomass-derived CO ₂ emissions in metric tons Carbon/yr
						E = A * C	F = E*12/44/2.205/1000
Example: Bark Boiler	Bark	500,000	MMBtu (HHV)	241	lb CO ₂ / MMBtu HHV	120,500,000	14,900
Total Biomass Carbon Released as CO ₂ from Combustion of Wood , Bark, or Other Biomass							
Explain the method used to determine ownership/control of sources not completely owned by the company. A protocol such as the WRI/WBCSD GHG Protocol can be used for guidance on determining ownership/control. Include any other information that is needed to understand the inventory results:							
* Emission factor for solid biomass from Intergovernmental Panel on Climate Change (IPCC). 1997. <i>Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual (Volume 3)</i>. Table 1.1, corrected for 1% unburned carbon (USEPA 2001b), converted to terms of HHV using the factor 0.95 and converted to “English” units of lb CO₂/MMBtu							

ANNEX H

TABLES OF GHG EMISSION FACTORS

These tables are copied from the main body of this report. Table numbers are consistent with numbering in the main text.

Table 2. IPCC Default CO₂ Emission Factors for Fossil Fuels (after IPCC 1997b)

Fossil Fuel	Uncorrected Emission Factor*		Emission Factor Corrected for Unoxidized Carbon	
	kg CO ₂ /TJ (HHV)	lb CO ₂ /MMBtu (HHV)	kg CO ₂ /TJ (HHV)	lb CO ₂ /MMBtu (HHV)
Crude oil	69,700	162	69,000	160
Gasoline	65,800	153	65,200	152
Kerosene	68,300	159	67,600	157
Diesel oil	70,400	164	69,700	162
Residual fuel oil	73,500	171	72,800	169
LPG	59,900	139	59,300	138
Petroleum coke	95,800	223	94,800	221
Anthracite coal	93,400	217	91,500	213
Bituminous coal	89,900	209	88,100	205
Sub-bituminous coal	91,300	212	89,400	208
Lignite	96,100	224	94,200	219
Peat	101,000	234	99,700	232
Natural gas	50,500	117	50,200	117

* these factors assume no unoxidized carbon; to account for unoxidized carbon, IPCC suggests multiplying by these default factors: coal = 0.98, oil = 0.99, and gas = 0.995 (factors presented in the table are rounded to three significant figures)

Table 4. IPCC Tier 1 CH₄ and N₂O Emission Factors for Stationary Combustion*
(from IPCC 1997c)

	CH ₄ Emission Factors		N ₂ O Emission Factors	
	lb/MMBtu HHV	kg/TJ HHV	lb/MMBtu HHV	kg/TJ HHV
Coal	0.02	10	0.0031 [†]	1.3 [†]
Natural gas	0.01	5	0.0002	0.1
Oil	0.004	2	0.001	0.6
Wood/wood residuals	0.07	30	0.009	4

* converted from a basis of LHV to HHV using the IPCC recommended multipliers 0.90 for natural gas and 0.95 for all other fuels; rounded to one significant digit, unless noted otherwise

[†] rounded to two significant digits

Table 5. IPCC Tier 2 Uncontrolled CH₄ and N₂O Emission Factors
for Industrial Boilers (from IPCC 1997c)

Fuel	Technology/ Configuration	CH ₄ Emission Factors		N ₂ O Emission Factors	
		lb/MMBtu (HHV)	kg/TJ (HHV)	lb/MMBtu (HHV)	kg/TJ (HHV)
Bituminous coal	Overfeed stoker boilers	0.002	0.95	0.0035	1.5
Sub-bituminous coal	Overfeed stoker boilers	0.002	0.95	0.0035	1.5
Bituminous coal	Underfeed stoker boilers	0.031	13	0.0035	1.5
Sub-bituminous coal	Underfeed stoker boilers	0.031	13	0.0035	1.5
Bituminous coal	Pulverized/ Dry bottom, wall fired	0.0015	0.7†	0.0035	1.5
Bituminous coal	Pulverized/ Dry bottom, tangentially fired	0.0015	0.7†	0.001	0.5†
Bituminous coal	Pulverized/ Wet bottom	0.002	0.9†	0.0035	1.5
Bituminous coal	Spreader Stoker	0.002	0.95	0.0035	1.5
Bituminous coal	Fluidized bed / Circulating or bubbling	0.002	0.95	0.21	91
Sub-bituminous coal	Fluidized bed/ Circulating or bubbling	0.002	0.95	0.21	91
Anthracite		0.02*	10*†	0.0031*	1.3*
Residual oil		0.007	2.9	0.0007	0.3†
Distillate oil		0.0004	0.2†	0.0009	0.4†
Natural gas	Boilers	0.0029	1.3	0.0002*	0.1*†
Natural gas	Turbines	0.001	0.5	0.0002*	0.1*†
Natural gas	Int. combustion engine /2-cycle lean burn	0.036	15	0.0002*	0.1*†
Natural gas	Int. combustion engine /4-cycle lean burn	0.027	12	0.0002*	0.1*†
Natural gas	Int. combustion engine /4-cycle rich burn	0.0061	2.6	0.0002*	0.1*†

* IPCC Tier 1 generic emission factors for coal and natural gas; Tier 2 emission factors are not available

† due to rounding to the appropriate number of significant digits, the factor in terms of HHV is numerically equivalent to the factor as provided in IPCC 1997c in terms of LHV

Table 6. Emission Factors for CH₄ and N₂O from Biomass Combustion

Emission Factor Description	CH ₄ Emission Factors		N ₂ O Emission Factors		Reference
	lb/MMBtu (HHV)	kg/TJ (HHV)	lb/MMBtu (HHV)	kg/TJ (HHV)	
Wood residual fuel-fired boilers					
Wood, wood residuals, and other biomass and wastes	0.07	30†	0.009	4†	Tier 1 – IPCC 1997c
Uncontrolled emissions from wood-fired stoker boilers	0.033	14	–	–	Tier 2 – IPCC 1997c
Average for wood residue combustion	0.021	9.0	0.013	5.6	USEPA 2001
Average for circulating fluidized bed boilers burning peat or bark	0.002	1†	0.019	8.4	Fortum 2001
Average for bubbling fluidized bed boilers burning peat or bark	0.004*	2*†	<0.004	<2†	Fortum 2001
Pre-1980 wood residue-fired stoker boilers sampled ahead of control devices	0.018	7.8	–	–	NCASI 1980
Pre-1980 wood residue-fired stoker boilers sampled after wet scrubbers	0.0060	2.6	–	–	NCASI 1985
Wood fired boiler	0.091 ^λ	39 ^λ	0.0069 ^λ	2.9 ^λ	JPA 2002
Wood as fuel	0.053 ^λ	23 ^λ	0.0075 ^λ	3.2 ^λ	AEA 2001
Wood residuals	0.07	30†	0.01	5†	SEPA 2001
<i>Median emission factors for wood residuals</i>	<i>0.027</i>	<i>11</i>	<i>0.009</i>	<i>4†</i>	
	0.0-0.09	1-40†	0.0031-0.17	1.3-71	EEA 1999

[†] due to rounding to the appropriate number of significant digits, the factor in terms of HHV is numerically equivalent to the factor as provided in the original reference source in terms of LHV

* excludes one very high number associated with low oxygen-high carbon monoxide conditions

^λ based on heat content of 21.1 GJ (HHV)/tonne (18.1 MMBtu (HHV)/ton) dry solids

Table 7. Default Fuel Economy and Emission Factors for Different Types of Mobile Sources and Activity Data (from WRI 2001d)

Vehicle Characteristics			Emission Factor	
Vehicle Type	MPG	Liters/100 km	lb CO ₂ /mile	gram CO ₂ /km
New small gas/electric hybrid	56	4.2	0.3554	100.1
Small gas auto, highway	32	7.3	0.6216	175.1
Small gas auto, city	26	9.0	0.7650	215.5
Med gas auto, highway	30	7.8	0.6631	186.8
Med gas auto, city	22	10.7	0.9042	254.7
Large gas automobile, hwy	25	9.4	0.7956	224.1
Large gas automobile, city	18	13.1	1.105	311.3
Med station wagon, hwy	27	8.7	0.7366	207.5
Med station wagon, city	20	11.8	0.9944	280.1
Mini van, hwy	24	9.8	0.8289	233.5
Mini van, city	18	13.1	1.105	311.3
Large van, hwy	18	13.1	1.105	311.3
Large van, city	14	16.8	1.421	400.2
Mid size pick-up truck, hwy	22	10.7	0.9042	254.7
Pick-up truck, city	17	13.8	1.170	329.6
Large pick-up truck, hwy	18	13.1	1.105	311.3
Large pick-up truck, city	15	15.7	1.326	373.5
LPG automobile	21	11.2	0.944	266
Diesel automobile	24	9.8	0.827	233
Gasoline light truck	14	16.8	1.420	400
Gasoline heavy truck	6	39.2	3.28	924
Diesel light truck	15	15.7	1.33	374
Diesel heavy truck	7	33.6	3.09	870
Light motorcycle	60	3.9	0.330	93
Diesel bus	6.7	35.1	3.674	1035

Table 8a. Fuel Consumption-Based Emission Factors [“English” units]
for Non-Road Mobile Sources and Machinery (IPCC 1997c)
(IPCC Revised 1996 Guidelines taken from EMEP/CORINAIR)

Source and Engine Type	lb CO ₂ / MMBtu (HHV)	lb CH ₄ / MMBtu (HHV)	lb N ₂ O/ MMBtu (HHV)	lb CO ₂ -equiv./ MMBtu (HHV)
Forestry – diesel	162*	0.009	0.066	183
Industry – diesel	162*	0.009	0.066	183
Railways – diesel	162*	0.009	0.066	183
Inland waterway – diesel	162*	0.009	0.066	183
Marine – diesel	162*	0.016	0.004	164
Industry – gasoline 4-stroke	152*	0.1	0.004	155
Forestry – gasoline 2-stroke	152*	0.38	0.0009	160
Industry – gasoline 2-stroke	152*	0.29	0.0009	158
Inland waterway – gasoline 4-stroke	152*	0.09	0.004	155
Inland waterway – gasoline 2-stroke	152*	0.24	0.0009	157

* from Table 2, corrected for unburned carbon

† due to rounding to the appropriate number of significant digits, the factor in terms of HHV is numerically equivalent to the factor as provided in IPCC 1997c in terms of LHV

Table 8b. Fuel Consumption-Based Emission Factors [SI units]
for Non-Road Mobile Sources and Machinery (IPCC 1997c)
(IPCC Revised 1996 Guidelines taken from EMEP/CORINAIR)

Source and Engine Type	kg CO ₂ /TJ (HHV)	kg CH ₄ /TJ (HHV)	kg N ₂ O/TJ (HHV)	kg CO ₂ -equiv./TJ (HHV)
Forestry – diesel	69,700*	4†	30†	78,600
Industry – diesel	69,700*	4†	30†	78,600
Railways – diesel	69,700*	4†	30†	78,600
Inland waterway – diesel	69,700*	4†	30†	78,600
Marine – diesel	69,700*	7†	2†	70,400
Industry – gasoline 4-stroke	65,200*	50†	2†	66,800
Forestry – gasoline 2-stroke	65,200*	160	0.4†	68,700
Industry – gasoline 2-stroke	65,200*	120	0.4†	67,900
Inland waterway – gasoline 4-stroke	65,200*	40†	2†	66,600
Inland waterway – gasoline 2-stroke	65,200*	100	0.4†	67,500

* from Table 2, corrected for unburned carbon

† due to rounding to the appropriate number of significant digits, the factor in terms of HHV is numerically equivalent to the factor as provided in IPCC 1997c in terms of LHV

ANNEX I

EXAMPLE CALCULATIONS IN SI UNITS

Example Calculation II: CO₂, CH₄, and N₂O emissions from natural gas use at a plywood manufacturing facility.

A manufacturing facility uses natural gas in a small boiler and in several veneer dryers in the production of plywood. The annual production for the year of interest was 150 MMSF (3/8 inch basis). The facility's records indicate that over a year's time it used 17 million standard cubic meters of natural gas. The facility does not have fuel meters on the individual combustion devices, but estimates that half of the gas is consumed by the boiler and the rest in the veneer dryers.

The facility does not know the carbon content of its natural gas supply, but the IPCC emission factor is 50.2 metric tonnes CO₂/TJ HHV (after correcting for 0.5% unoxidized carbon). The facility estimates the heating value of the natural gas to be 0.0371 GJ HHV/standard cubic meter. Because the facility has no data on CH₄ or N₂O emissions from the veneer dryers, it has decided to use the IPCC Tier 1 emission factors, as shown in Table 3 (5 kg CH₄/TJ HHV and 0.1 kg N₂O/TJ HHV) for all natural gas consumption at the facility. The annual emissions are estimated as follows.

Total facility CO₂ emissions:

- $(17 \times 10^6 \text{ m}^3 \text{ gas/y}) \times (0.0371 \text{ GJ HHV/m}^3) \times (1 \text{ TJ}/1000 \text{ GJ}) = 631 \text{ TJ HHV/y}$
- $(631 \text{ TJ HHV/y}) \times (50.2 \text{ tonne CO}_2/\text{TJ HHV}) = 31,700 \text{ tonne CO}_2/\text{y}$

Total facility CH₄ emissions:

- $(631 \text{ TJ HHV/y}) \times (5 \text{ kg CH}_4/\text{TJ HHV}) = 3150 \text{ kg CH}_4/\text{y} = 3.15 \text{ tonne CH}_4/\text{y}$
- Using the IPCC GWP of 21, this is equal to 66.2 tonne CO₂-equiv/y

Total facility N₂O emissions

- $(631 \text{ TJ HHV/y}) \times (0.1 \text{ kg N}_2\text{O}/\text{TJ HHV}) = 63.1 \text{ kg N}_2\text{O}/\text{y} = 0.0631 \text{ tonne N}_2\text{O}/\text{y}$
- Using the IPCC GWP of 310, this is equal to 19.6 tonne CO₂-equiv/y

Total GHG emissions = $31,700 + 66.2 + 19.6 = 31,800 \text{ tonne CO}_2\text{-equiv/y}$

On a CO₂-equivalents basis, combined CH₄ and N₂O emissions are about 0.1% of CO₂ emissions. CH₄ and N₂O emissions would be very small even if the emission factors were several times larger than those used in the calculations. Because of this, the company might decide against including CH₄ and N₂O estimates in the results, and instead indicate that the estimates demonstrate that the CH₄ and N₂O emissions are not material to the results of the inventory because they are less than 0.1% of CO₂ emissions.

Example Calculation I2: CO₂, CH₄, and N₂O emissions from a large dry-bottom, wall fired boiler burning pulverized bituminous coal.

The boiler produces 350,000 kg steam per hour (about 770,000 lb/hr). Over a year's time, the company's records indicate that the boiler consumed 336,000 tonne (370,000 short tons) of coal having a higher heating value, on average, of 30.2 GJ HHV/tonne.

Case 1: CO₂ emissions based on carbon content of fuel

The company has information on the carbon content of the coal being burned in the boiler (80.1% carbon, by weight). The company decides that the default IPCC correction for unburned carbon in coal-fired boilers (2% unburned carbon) is appropriate. The company decides to use the Tier 2 IPCC emission factors for CH₄ and N₂O from Table 4. The IPCC Tier 2 emission factors for dry bottom, wall fired boilers burning pulverized bituminous coal are 0.7 kg CH₄/TJ HHV and 1.5 kg N₂O/TJ HHV. The annual emissions of CO₂, CH₄, and N₂O are estimated as follows.

CO₂ emissions:

- $(336,000 \text{ tonne/y coal}) \times (0.801 \text{ tonne carbon / tonne coal}) \times (0.98 \text{ tonne carbon burned}) \times (44 \text{ tonne CO}_2 / 12 \text{ tonne carbon}) = 967,000 \text{ tonne CO}_2/\text{yr}$

CH₄ emissions:

- $(336,000 \text{ tonne/y}) \times (30.2 \text{ GJ HHV/tonne}) \times (1 \text{ TJ/1000 GJ}) \times (0.7 \text{ kg CH}_4/\text{TJ HHV}) = 7100 \text{ kg CH}_4/\text{yr}$ or 7.10 tonne CH₄/y

Using the IPCC GWP of 21 for CH₄, this equates to 149 tonne CO₂-equiv/y

N₂O emissions:

- $(336,000 \text{ tonne/y}) \times (30.2 \text{ GJ HHV/tonne}) \times (1 \text{ TJ/1000 GJ}) \times (1.5 \text{ kg N}_2\text{O/TJ HHV}) = 15,220 \text{ kg N}_2\text{O/yr}$ or 15.2 tonne N₂O/yr

Using the IPCC GWP of 310 for N₂O, is to 4720 tonne CO₂-equiv/y

Total GHG emissions = 967,000 + 149 + 4,720 = 972,000 tonne CO₂-equiv/y

Compared to its CO₂ emissions, emissions of CH₄ and N₂O from this boiler are very small.

CO₂ emissions = 967,000 tonne CO₂/y

CH₄ emissions = 149 tonne CO₂-equiv/y or 0.015% of CO₂ emissions

N₂O emissions = 4,720 tonne CO₂-equiv/y or about 0.5% of CO₂ emissions

Case 2: CO₂ emissions based on emission factors

In this case the company does not have information on the carbon content of the coal being burned in the boiler. The IPCC default Tier 1 emission factor for CO₂ is 89.9 tonne CO₂/TJ HHV. The company decides that the default IPCC correction for unburned carbon in coal-fired boilers (2% unburned carbon) is appropriate.

CO₂ emissions:

- $(336,000 \text{ tonne/y}) \times (30.2 \text{ GJ HHV/tonne}) \times (89.9 \text{ kg CH}_4/\text{TJ HHV})$
= $912 \times 10^6 \text{ kg CO}_2/\text{yr}$ or 912,000 tonne CH₄/y
- CO₂ emissions corrected for 2% unburned carbon = $894 \times 10^3 \text{ tonne CO}_2/\text{y}$

Methane and nitrous oxide emissions are calculated as in Case 1.

CO₂ emissions = 894,000 tonne CO₂/y

CH₄ emissions = 149 tonne CO₂-equiv/y or 0.017% of CO₂ emissions

N₂O emissions = 4,720 tonne CO₂-equiv/y or about 0.5% of CO₂ emissions

As in the previous example, this comparison suggests that it may be relatively simple for many companies to document that emissions of CH₄ and N₂O from fossil fuel-fired boilers are not material to the results of their inventory.

Example Calculation I3: Manufacturing facility with a combination fuel boiler burning bark and oil.

A manufacturing facility has a 250,000 kg steam/hr (550,000 lb/hr) circulating fluidized bed (CFB) bark boiler. In a year, the boiler burns approximately 6.9×10^6 GJ LHV of bark and 0.8×10^6 GJ LHV of residual fuel oil. Because the boiler receives supplemental fossil fuel, it is recommended to estimate the CO_2 from the fossil fuel use and the CH_4 and N_2O emissions based on the total firing rate. The plant decides to use the IPCC emission factor for residual oil (72.8 tonne CO_2 /TJ HHV, after correcting for 1% unoxidized carbon) and to estimate CH_4 and N_2O emissions based on the total firing rate and the emission factors developed by Fortum on CFB boilers. The average emission factors found by Fortum, shown in Table 5, are 1 kg CH_4 /TJ HHV and 8.4 kg N_2O /TJ HHV.

CO_2 emissions from fossil fuel:

- $(0.8 \times 10^6 \text{ GJ LHV/y}) = (0.8 \times 10^3 \text{ TJ LHV/y})$
- for oil LHV is 0.95 times HHV (Section 4.3.2)
- $(0.8 \times 10^3 \text{ TJ LHV/y}) / (0.95 \text{ TJ LHV/TJ HHV}) = 0.842 \times 10^3 \text{ TJ HHV}$
- $(0.842 \times 10^3 \text{ TJ HHV/y}) \times (72.8 \text{ tonne } \text{CO}_2/\text{TJ HHV}) = 61,300 \text{ tonne } \text{CO}_2/\text{y}$

CH_4 emissions:

- total heat input = $(6.9 \times 10^6 \text{ GJ LHV/y}) + (0.8 \times 10^6 \text{ GJ LHV/y}) = 7.7 \times 10^6 \text{ GJ LHV/y}$
 $= 7.7 \times 10^3 \text{ TJ LHV/y}$
- for oil and wood LHV is 0.95 times HHV (Section 4.3.2)
- $(7.7 \times 10^3 \text{ TJ LHV/y}) / (0.95 \text{ TJ LHV/TJ HHV}) = 8.1 \times 10^3 \text{ TJ HHV/y}$
- $(8.1 \times 10^3 \text{ TJ HHV/y}) \times (1 \text{ kg } \text{CH}_4/\text{TJ HHV}) = 8,100 \text{ kg } \text{CH}_4/\text{y} = 8.1 \text{ tonne } \text{CH}_4/\text{y}$

Using the IPCC warming potential of 21, this equates to 170 tonne CO_2 -equiv/y

N_2O emissions:

- total heat input = $8.1 \times 10^3 \text{ TJ HHV/y}$
- $(8.1 \times 10^3 \text{ TJ HHV/y}) \times (8.4 \text{ kg } \text{N}_2\text{O}/\text{TJ HHV}) = 68,100 \text{ kg } \text{N}_2\text{O}/\text{y} = 68.1 \text{ tonne } \text{N}_2\text{O}/\text{y}$

Using the IPCC warming potential of 310, this equates to 21,100 tonne CO_2 -equiv/y

Total CO_2 -equivalents emitted = $61,300 + 170 + 21,100 = 82,600 \text{ tonne } \text{CO}_2\text{-equiv/y}$

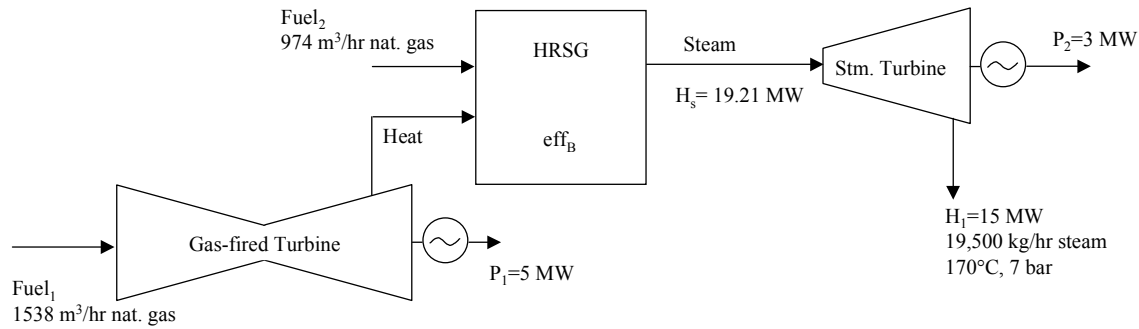
Example calculation I4: Manufacturing plant purchasing electrical power.

A plant in Alberta, Canada purchases 83,300 MWh of electrical power in a year's time. The Canadian VCR Registration Guide shows an average emission factor for purchased power in Alberta of 0.991 kg CO₂-equiv/kWh (see Annex C). The indirect emissions associated with the purchased power are estimated as follows.

- $83,300 \text{ MWh/y} = 83.3 \times 10^6 \text{ kWh/y}$
- $(83.3 \times 10^6 \text{ kWh/y}) \times (0.991 \text{ kg CO}_2\text{-equiv/kWh}) = 82.6 \times 10^6 \text{ kg CO}_2\text{-equiv/y}$
 $= 82,600 \text{ tonne CO}_2\text{-equiv/y}$

Example Calculation I5: Allocating CHP emissions to three output streams – simplified efficiency method with WRI/WBCSD recommended default efficiency factors.

A manufacturing plant has the CHP system shown in the figure, but it is lacking (or chooses not to use) detailed energy balance information. Instead, the company chooses to use the simplified efficiency method and the efficiencies recommended herein: 0.35 for power generation and 0.8 for steam generation.



Using these assumed efficiencies, emissions can be allocated among the three outputs of the CHP system as follows (using a basis of one hour of operation):

Total system emissions:

Fuel₁:

$$\text{CO}_2 \quad (1538 \text{ m}^3/\text{hr}) \times (0.0371 \text{ GJ HHV/m}^3) \times (50.2 \text{ kg CO}_2/\text{GJ HHV}) = 2864 \text{ kg CO}_2/\text{hr}$$

$$\text{CH}_4 \quad (1538 \text{ m}^3/\text{hr}) \times (0.0371 \text{ GJ HHV/m}^3) \times (0.0005 \text{ kg CH}_4/\text{GJ HHV}) \times (21 \text{ CO}_2\text{-equiv/CH}_4) = 0.60 \text{ kg CO}_2\text{-equiv/hr}$$

$$\text{N}_2\text{O} \quad (1538 \text{ m}^3/\text{hr}) \times (0.0371 \text{ GJ HHV/m}^3) \times (0.0001 \text{ kg N}_2\text{O}/\text{GJ HHV}) \times (310 \text{ CO}_2\text{-equiv/N}_2\text{O}) = 1.77 \text{ kg CO}_2\text{-equiv/hr}$$

$$\text{Total Fuel}_1 \text{ emissions} = 2866 \text{ kg CO}_2\text{-equiv/hr}$$

Fuel₂:

$$\text{CO}_2 \quad (974 \text{ m}^3/\text{hr}) \times (0.0371 \text{ GJ HHV/m}^3) \times (50.2 \text{ kg CO}_2/\text{GJ HHV}) = 1814 \text{ kg CO}_2/\text{hr}$$

$$\text{CH}_4 \quad (974 \text{ m}^3/\text{hr}) \times (0.0371 \text{ GJ HHV/m}^3) \times (0.0013 \text{ kg CH}_4/\text{GJ HHV}) \times (21 \text{ CO}_2\text{-equiv/CH}_4) = 0.99 \text{ kg CO}_2\text{-equiv/hr}$$

$$\text{N}_2\text{O} \quad (974 \text{ m}^3/\text{hr}) \times (0.0371 \text{ GJ HHV/m}^3) \times (0.0001 \text{ kg N}_2\text{O}/\text{GJ HHV}) \times (310 \text{ CO}_2\text{-equiv/N}_2\text{O}) = 1.12 \text{ kg CO}_2\text{-equiv/hr}$$

$$\text{Total Fuel}_2 \text{ emissions} = 1816 \text{ kg CO}_2\text{-equiv/hr}$$

$$\text{Total CHP system emissions} = 2866 + 1816 = 4682 \text{ kg CO}_2\text{-equiv/hr}$$

$$\text{Total system power output} = P_1 + P_2 = 8 \text{ MW}$$

$$R_{eff} = \frac{0.8}{0.35} = 2.3$$

$$E_H = \left\{ \frac{15MW}{15MW + (8MW \times 2.3)} \right\} \times 4682 kgCO_2 eq = 2103 kgCO_2 eq = 17,700 \text{ tonne } CO_2 \text{ equiv/y at 350 d/y operation}$$

$$E_P = 4682 kgCO_2 eq - 2103 kgCO_2 eq = 2579 kgCO_2 eq = 21,700 \text{ tonne } CO_2 \text{ equiv/yr at 350 d/y operation}$$

Using the simplified efficiency method with default power and steam efficiency factors, therefore, the emissions from the CHP system are allocated to the output streams in the following percentages:

- Percentage of CHP emissions to heat output = $100 \times 2103 / 4682 = 44.9\%$
- Percentage of CHP emissions to power output = $100 \times 2579 / 4682 = 55.1\%$

These percentages can be used to allocate all GHG emissions from the CHP system.

Emission factors can be developed for the energy outputs:

- Emission factor for CHP heat output = $(2103 \text{ kg } CO_2\text{-equiv/hr}) / 15 \text{ MW}$
= 140 kg CO₂-equiv/MWh
- Emission factor for CHP power output = $(2579 \text{ kg } CO_2\text{-equiv/hr}) / 8 \text{ MW}$
= 322 kg CO₂-equiv/MWh

Example calculation I6: GHG emissions from on-site vehicles and equipment.

Based on purchasing records, a company estimates the amounts of fuel purchased over a year to fuel on-site vehicles and equipment. It applies the largest of the emission factors shown in Table 1 and estimates that the emissions are much less than 0.5% of the plant's emissions. Rather than trying to develop a more accurate estimate, the company decides to report in the results only that the emissions from this source are non-material because they represent less than 0.5% of the total emissions.

Example calculation I7: GHG emissions from a company's forestry operations and wood transport fleet.

A company's fuel purchasing records indicate that, in a year, the following amounts of fuel are consumed by the company's woodlands operations and its fleet of trucks used to transport wood to the manufacturing plant:

- Gasoline = 10,000 l – The company estimates that approximately 90% of this is used in 4-stroke engines and 10% is used in 2-stroke engines in forestry equipment.
- Diesel = 200,000 l

The heat content of the gasoline is estimated to be 0.034 GJ LHV/l and the heat content of the diesel fuel is 0.038 GJ LHV/l.

The company decides to use the CO₂-equivalent emission factors in Table 7 to estimate emissions.

- Gasoline used in 4-stroke engines = 10,000 l/y x 0.9 = 9,000 l/y
- (9,000 l/y) x (0.034 GJ LHV/liter) = 306 GJ LHV/y = 0.306 TJ LHV/y
- for gasoline LHV is 0.95 times HHV (Section 4.3.2)
- (0.306 TJ LHV/y) / (0.95 TJ LHV/TJ HHV) = 0.322 TJ HHV/y
- (0.322 TJ HHV/y) x (66,800 kg CO₂-equiv/TJ HHV) = 21,500 kg CO₂-equiv/y
= 21.5 tonne CO₂-equiv/y
- Gasoline used in 2-stroke engines = 10,000 l/y x 0.1 = 1,000 l/y
- (1,000 l/y) x (0.034 GJ LHV/liter) = 34 GJ LHV/y = 0.034 TJ LHV/y
- for gasoline LHV is 0.95 times HHV (Section 4.3.2)
- (0.034 TJ LHV/y) / (0.95 TJ LHV/TJ HHV) = 0.036 TJ HHV/y
- (0.036 TJ HHV/y) x (67,900 kg CO₂-equiv/TJ HHV) = 2440 kg CO₂-equiv/y
= 2.44 tonne CO₂-equiv/y
- Diesel used = 200,000 l/y
- (200,000 l/y) x (0.038 GJ LHV/l) = 7600 GJ LHV/y = 7.6 TJ LHV/y
- for diesel LHV is 0.95 times HHV (Section 4.3.2)
- (7.6 TJ LHV/y) / (0.95 TJ LHV/TJ HHV) = 8.0 TJ HHV/y
- (8.0 TJ HHV/y) x (78,600 kg CO₂-equiv/TJ LHV) = 628,800 kg CO₂-equiv/y
= 629 tonne CO₂-equiv/y

Total GHG emissions from company-owned forestry operations and wood trucks

- 21.5 + 2.44 + 629 = 653 tonne CO₂-equiv/y

Example Calculation I8: Emissions from a company-owned landfill with a modern low-permeability cap and gas collection system. The collected gas is burned. Measurements have been made on a landfill gas collection system. The system is collecting 820,000 standard m³/y and the gas is 47% methane by volume. The plant has no site-specific data on the efficiency of the gas collection system, so it uses the recommended default value of 75%. It also uses the default assumption that 10% of the uncollected gas is oxidized before escaping to the atmosphere.

- methane collected = $(820,000 \text{ m}^3/\text{y}) \times (0.47) = 385,000 \text{ m}^3/\text{y}$
- methane generated = $(385,000 \text{ m}^3/\text{y}) / (0.75) = 514,000 \text{ m}^3/\text{y}$
- methane released = $(514,000 - 385,000 \text{ m}^3/\text{y}) \times (1 - 0.1) = 116,000 \text{ m}^3/\text{y} = 116 \times 10^6 \text{ l/y}$
- methane released = $(116 \times 10^6 \text{ l/y}) / (22.4 \text{ l/g-mole}) = 5.16 \times 10^6 \text{ g-mole/y}$
- methane released = $(5.16 \times 10^6 \text{ g-mole/y}) \times (16 \text{ g/g-mole}) = 82.6 \times 10^6 \text{ g/y}$
= 82.6 tonne CH₄/y

Using the IPCC GWP (21), this is equal to 1730 tonne CO₂-equiv/y

Example calculation I9: Emissions from 20 year old landfill receiving wood products plant log yard debris and boiler ash. The landfill does not have a gas collection system. A plant landfills 75 tonne per day of solid waste composed primarily of log yard debris, boiler ash, and other miscellaneous waste typical of a wood products manufacturing plant. The plant generates waste 350 days a year. The landfill has been in use for 20 years and is still active. The landfill does not have a gas recovery system. The plant uses the default values for k and L_0 shown in Table 8 ($100 \text{ m}^3/\text{Mg}$ for L_0 and 0.03 y^{-1} for k).

The plant estimates that one third of the material sent to the landfill is inerts (e.g., concrete and ash). Therefore, the deposition rate is adjusted to 50 tonne per day.

$$R = 50 \text{ tonne/d} \times 350 \text{ d/y} = 17,500 \text{ tonne/y}$$

$$L_0 = 100 \text{ m}^3/\text{tonne}$$

$$k = 0.03/\text{y}$$

$$C = 0 \text{ y}$$

$$T = 20 \text{ y}$$

- methane generated (m^3/y) = $(17,500 \text{ tonne/y}) \times (100 \text{ m}^3 \text{ CH}_4/\text{tonne}) \times (e^{-0.03 \times 0} - e^{-0.03 \times 20})$
= $790,000 \text{ m}^3 \text{ CH}_4/\text{y}$
- density of methane (0°C and 1 atm. pressure) = 0.7167 kg/m^3 (Green 1984)
- methane generated (kg/y) = $(790,000 \text{ m}^3/\text{y}) \times (0.7167 \text{ kg/m}^3) = 566,000 \text{ kg CH}_4/\text{y}$
= $566 \text{ tonne CH}_4/\text{y}$
- assume 10% oxidation in landfill cover
- methane released = $(566 \text{ tonne CH}_4/\text{y}) \times (1 - 0.1) = 509 \text{ tonne CH}_4/\text{y}$ released

Using the IPCC GWP (21), this equals $10,700 \text{ tonne CO}_2\text{-equiv/y}$

Note that the Table 1 emission factor would have yielded an estimate of $50 \text{ tonne/d} \times 350 \text{ d/y} \times 3,500 \text{ kg/t} = 61,250,000 \text{ kg/y} = 61,250 \text{ tonne CO}_2\text{-equiv/y}$, over five times the estimate developed using the more refined approach.

Example calculation I10: Wood products plant with anaerobic treatment but no gas recovery.

A wood products manufacturing plant uses an anaerobic treatment plant to treat wastewater containing 10,000 kg COD/d. The plant generates wastewater 300 days per year. The IPCC default value for CH₄ generation from anaerobic treatment systems is 0.25 kg CH₄/kg COD in the feed. The CH₄ emissions are calculated as follows.

- amount of organic carbon = 10,000 kg/d x 300 d/y = 3,000,000 kg COD/y
- CH₄ generated = 3,000,000 kg COD/y x 0.25 kg CH₄/kg COD = 750,000 kg CH₄/y
= 750 tonne CH₄/y

Using the IPCC GWP (21), this equals 15,750 tonne CO₂-equiv/y

Example Calculation III: Combination boiler providing 91,000 kg/hr steam from wood residuals and natural gas

A plywood plant operates a boiler that provides an average of 91,000 kg/hr of steam (1022° C, 27.6 bar). The boiler operates 24 hr/d, 350d/yr. The plant meters the natural gas consumption of the boiler, but not the firing rate of wood residual fuel. The efficiency of the boiler in producing steam from wood fuel is approximately 67%, and in producing steam from natural gas fuel is approximately 81%. The boiler consumed $22 \times 10^6 \text{ m}^3$ of gas in a year's time. The emissions can be estimated as follows:

Steam Production: 91,000 kg/hr
1022° C, 27.6 bar, 3.04 MJ/kg

$$\left(\frac{91,000 \text{ kg}}{\text{hr}} \right) \times \left(\frac{24 \text{ hr}}{\text{d}} \right) \times \left(\frac{350 \text{ d}}{\text{yr}} \right) \times \left(\frac{3.04 \times 10^{-6} \text{ TJ}}{\text{kg}} \right) = 2320 \text{ TJ steam/yr}$$

Natural gas consumption:

$$\left(\frac{22 \times 10^6 \text{ m}^3}{\text{yr}} \right) \times \left(\frac{37.7 \times 10^{-6} \text{ TJ HHV}}{\text{m}^3 \text{ gas}} \right) = 829 \text{ TJ HHV gas/yr}$$

Wood fuel consumption:

$$2320 \text{ TJ steam} = \left(\frac{0.81 \text{ TJ steam}}{1 \text{ TJ HHV gas}} \right) \times 829 \text{ TJ HHV gas} \\ + \left(\frac{0.67 \text{ TJ steam}}{1 \text{ TJ HHV wood}} \right) \times \text{amount of wood fuel}$$

$$\text{amount of wood fuel} = (2320 - 671 \text{ TJ steam}) \times \left(\frac{1 \text{ TJ HHV wood}}{0.67 \text{ TJ steam}} \right) \\ = 2460 \text{ TJ HHV wood fuel / yr}$$

Emissions from Natural Gas

CO₂ emissions:

The facility uses the median CO₂ emission factor corrected for unoxidized carbon for natural gas from Table 2.

$$\left(\frac{829 \text{ TJ HHV}}{\text{yr}} \right) \times \left(\frac{50,200 \text{ kg CO}_2}{\text{TJ HHV}} \right) = 41.6 \times 10^6 \text{ kg CO}_2.$$

The facility uses the IPCC Tier 2 emission factors for CH₄ and N₂O from Table 4.

CH₄ emissions:

$$\left(\frac{829 TJ \text{ HHV}}{yr} \right) \times \left(\frac{1.3 kg \text{ CH}_4}{TJ \text{ HHV}} \right) = 1080 \text{ kg CH}_4.$$

N₂O emissions:

$$\left(\frac{829 TJ \text{ HHV}}{yr} \right) \times \left(\frac{0.1 kg \text{ N}_2\text{O}}{TJ \text{ HHV}} \right) = 82.9 \text{ kg N}_2\text{O}$$

Emissions from Wood Fuel

CO₂ emissions:

CO₂ generated from combustion of biomass fuels should not be included in inventory results. However, the plant decides to compute emissions and report separately as supporting information, using the emission factor from Table H1.

$$\left(\frac{2,460 TJ \text{ HHV}}{yr} \right) \times \left(\frac{104 \times 10^3 kg \text{ CO}_2}{TJ \text{ HHV}} \right) = 256 \times 10^6 \text{ kg biomass-derived CO}_2/\text{yr}$$

For CH₄ and N₂O, the facility uses the median emission factors for biomass fuels from Table 5.

CH₄ emissions:

$$\left(\frac{2,460 TJ \text{ HHV}}{yr} \right) \times \left(\frac{11 kg \text{ CH}_4}{TJ \text{ HHV}} \right) = 27,100 \text{ kg CH}_4/\text{yr}$$

N₂O emissions:

$$\left(\frac{2,460 TJ \text{ HHV}}{yr} \right) \times \left(\frac{4 kg \text{ N}_2\text{O}}{TJ \text{ HHV}} \right) = 9,840 \text{ kg N}_2\text{O}/\text{yr}$$

Total GHG emissions expressed as metric tonnes CO₂ equivalents:

$$\left[\left(41.6 \times 10^6 kg \text{ CO}_2 \right) + \left(1080 + 27,100 kg \text{ CH}_4 \right) \times \left(21 \frac{kg \text{ CO}_2 \text{ eq.}}{kg \text{ CH}_4} \right) + \left(82.9 + 9,840 kg \text{ N}_2\text{O} \right) \times \left(310 \frac{kg \text{ CO}_2 \text{ eq.}}{kg \text{ N}_2\text{O}} \right) \right] \\ \times \left(\frac{1 \text{ tonne}}{1000 kg} \right) = 45,300 \text{ metric tonnes CO}_2 \text{ eq./yr}$$

Example Calculation I12: Teepee burner combusting wood residuals

A wood products facility operates a teepee burner to burn its wood residuals. The facility estimates that 110 million kilograms of residuals were burned in the unit during a year's time. The facility estimates the moisture content of the fuel at 35% (wet basis), and heating value of 20 GJ (HHV) per metric tonne (1000 kg) of fuel.

CO₂ emissions:

CO₂ generated from combustion of biomass fuels should not be included in inventory results. However, the plant decides to compute emissions and report separately as supporting information, using the emission factor from Table H1.

$$(110 \times 10^6 \text{ kg wood @ } 35\% H_2O) \times \left(\frac{0.65 \text{ kg wood}}{1 \text{ kg wet wood}} \right) \times \left(\frac{1 \text{ tonne}}{1000 \text{ kg}} \right) \times \left(\frac{20 \text{ GJ HHV}}{\text{tonne}} \right) \\ = 1,430,000 \text{ GJ HHV}$$

$$(1,430 \text{ TJ HHV}) \times \left(\frac{104 \times 10^3 \text{ kg CO}_2}{\text{TJ HHV}} \right) = 149 \times 10^6 \text{ kg biomass-derived CO}_2/\text{yr}$$

For CH₄ and N₂O, the facility uses the IPCC Tier 1 emission factors from Table 5.

CH₄ emissions:

$$(1,430 \text{ TJ HHV}) \times \left(\frac{30 \text{ kg CH}_4}{\text{TJ HHV}} \right) = 42,900 \text{ kg CH}_4/\text{yr}$$

N₂O emissions:

$$(1,430 \text{ TJ HHV}) \times \left(\frac{4 \text{ kg N}_2\text{O}}{\text{TJ HHV}} \right) = 5,720 \text{ lb N}_2\text{O}/\text{yr}$$

Total GHG emissions expressed as metric tonnes CO₂ equivalents:

$$\left[(42,900 \text{ kg CH}_4) \times \left(\frac{21 \text{ kg CO}_2 \text{ eq.}}{\text{kg CH}_4} \right) + (5,720 \text{ kg N}_2\text{O}) \times \left(\frac{310 \text{ kg CO}_2 \text{ eq.}}{\text{kg N}_2\text{O}} \right) \right] \times \left(\frac{1 \text{ tonne}}{1000 \text{ kg}} \right) \\ = 2670 \text{ metric tonnes CO}_2\text{-equiv}/\text{yr}$$

Example Calculation I13: Estimating emissions based on emission testing results.

A plywood plant operates an RCO to control emissions from veneer dryers. The veneer dryers are direct-fired with natural gas, and the RCO consumes natural gas as well. The facility has access to recent emission source testing results at the inlet and outlet of the RCO, and is interested in calculating methane emissions based on the testing results. The calculated methane emissions will be used to adjust the CO₂ emissions estimated based on emission factors.

The facility operates 24 hr/d, 350 d/yr.

Test Results:

RCO inlet (dryer exhaust):

- Avg. RCO inlet flowrate: 831 m³/min (dry)
- Avg. methane concentration (dry): 49 ppm

RCO exhaust:

- Avg. RCO exhaust flowrate: 868 m³/min (dry)
- Avg. methane concentration (dry): 67 ppm

Avg. natural gas consumption in RCO: 30 m³/hr

Avg. natural gas consumption in veneer dryers: 960 m³/hr

CH₄ emissions based on emissions test results:

RCO inlet:

$$\left(\frac{831\text{m}^3}{\text{min}}\right) \times (49\text{ ppm dry}) \times \left(\frac{1}{10^6}\right) \times \left(\frac{1\text{kgmol}}{22.4\text{m}^3}\right) \times \left(\frac{16\text{kg}}{\text{kgmol}}\right) \times \left(\frac{60\text{min}}{\text{hr}}\right) \times \left(\frac{24\text{hr}}{\text{d}}\right) \times \left(\frac{350\text{d}}{\text{yr}}\right)$$

= 14,700 kg CH₄/yr

RCO exhaust:

$$\left(\frac{868\text{m}^3}{\text{min}}\right) \times (67\text{ ppm dry}) \times \left(\frac{1}{10^6}\right) \times \left(\frac{1\text{kgmol}}{22.4\text{m}^3}\right) \times \left(\frac{16\text{kg}}{\text{kgmol}}\right) \times \left(\frac{60\text{min}}{\text{hr}}\right) \times \left(\frac{24\text{hr}}{\text{d}}\right) \times \left(\frac{350\text{d}}{\text{yr}}\right)$$

= 20,900 kg CH₄/yr

Difference between RCO inlet and exhaust (corresponds to methane emissions contribution of the RCO):

$$20,900 - 14,700 = 6,200 \text{ kg CH}_4/\text{yr}$$

This result indicates that the RCO was not effective in destroying the methane in the dryer exhaust, but rather contributed to total methane emissions.

The facility has estimated CO₂ emissions based on the activity data (fuel consumption) combined with the IPCC Tier I emission factor for natural gas (as listed in Table 2). The facility has decided to adjust this CO₂ emissions estimate based on the results of the

emissions testing, because the emission test results indicate that a portion of the natural gas fuel sent to the dryer and the RCO was not combusted (i.e., not converted to CO₂) but rather was emitted as methane. In other words, the assumption that all fuel sent to the combustion devices was oxidized to CO₂ was incorrect. The adjustment can be made as follows:

CO₂ estimate based on emission factor:

$$\left(30 + 960 \frac{m^3}{hr}\right) \times \left(\frac{0.03723 \text{ GJ HHV}}{m^3 \text{ gas}}\right) \times \left(\frac{50.2 \text{ kg CO}_2}{\text{GJ HHV}}\right) \times \left(\frac{24 \text{ hr}}{d}\right) \times \left(\frac{350 d}{yr}\right)$$

$$= 15,500,000 \text{ kg CO}_2/\text{yr}$$

The methane emissions corresponding to dryer and RCO fuel which was emitted as unburned methane (20,900 kg per year), computed based on emission testing results, represent approximately 0.3% of the total fuel sent to the combustion devices. Since each pound of carbon in the uncombusted fuel (methane) corresponds to one pound of carbon in CO₂ which would have been emitted if the fuel had been oxidized, the CO₂ estimate can be adjusted by subtracting the mass of carbon in unburned CH₄ (converted to an equivalent mass of CO₂) in the RCO exhaust:

$$(15,500,000 \text{ kg CO}_2 / \text{yr}) - (20,900 \text{ kg CH}_4 / \text{yr}) \times \left(\frac{1 \text{ kg C}}{16 \text{ kg CH}_4}\right) \times \left(\frac{44 \text{ kg CO}_2}{1 \text{ kg C}}\right)$$

$$= 15,400,000 \text{ kg CO}_2 / \text{yr}$$

The facility is interested in comparing the methane emission estimate based on source test results to an estimate based on fuel consumption and the IPCC Tier 1 methane emission factor from Table 3. The calculation is based on the total natural gas consumption in the veneer dryers and the RCO.

$$\left(30 + 960 \frac{m^3}{hr}\right) \times \left(\frac{0.03723 \text{ GJ HHV}}{m^3 \text{ gas}}\right) \times \left(\frac{0.005 \text{ kg CH}_4}{\text{GJ HHV}}\right) \times \left(\frac{24 \text{ hr}}{d}\right) \times \left(\frac{350 d}{yr}\right)$$

$$= 1,550 \text{ kg CH}_4/\text{yr}$$

The emissions estimate based on source test results (20,900 kg CH₄/yr) is approximately 14 times greater than the estimate based on fuel consumption and the Tier 1 emissions factor (1,550 kg CH₄/yr). This illustrates that:

- 1) uncertainty associated with methane emissions estimates can be high
- 2) some natural gas direct fired combustion devices can emit significant quantities of uncombusted methane, and
- 3) due to low combustion temperatures, RCOs are generally not effective at controlling methane emissions

The source testing did not include analysis of nitrous oxide emissions. Therefore, the facility decided to base nitrous oxide emission estimates on fuel combustion data and IPCC Tier I emission factors. The facility also decided to adjust the activity data (data on fuel consumption in the combustion devices) to account for unburned fuel as indicated by the methane emission test results.

$$\left(\frac{15.5 - \left[0.0209 \times \left(\frac{44}{16} \right) \right]}{15.5} \right) \times \left(30 + 960 \frac{m^3}{hr} \right) \times \left(\frac{0.03723 GJ \text{ HHV}}{m^3 \text{ gas}} \right) \times \left(\frac{0.0001 kg \text{ N}_2O}{GJ \text{ HHV}} \right) \times \left(\frac{24 hr}{d} \right) \times \left(\frac{350 d}{yr} \right)$$

= 30.8 kg N₂O/yr

Overall GHG emissions expressed as CO₂ equivalents:

$$15,400,000 \text{ kg CO}_2/\text{yr} + (20,900 \text{ kg CH}_4/\text{yr}) \times (21) + (30.8 \text{ kg N}_2O/\text{yr}) \times (310)$$

= 15,800,000 kg CO₂-equiv/yr

ANNEX J

EXAMPLE CALCULATIONS IN “ENGLISH” UNITS

Example Calculation J1: CO₂, CH₄, and N₂O emissions from natural gas use at a plywood manufacturing facility.

A manufacturing facility uses natural gas in a small boiler and in several veneer dryers in the production of plywood. The annual production for the year of interest was 150 MMSF (3/8 inch basis). The facility's records indicate that over a year's time it used 600 million standard cubic feet of natural gas. The facility does not have fuel meters on the individual combustion devices, but estimates that half of the gas is consumed by the boiler and the rest in the veneer dryers.

The facility does not know the carbon content of its natural gas supply, but the IPCC emission factor is 117 lb CO₂/MMBtu HHV (after correcting for 0.5% unoxidized carbon). The facility estimates the heating value of the natural gas to be 1050 MMBtu HHV/standard cubic foot. Because the facility has no data on CH₄ or N₂O emissions from the veneer dryers, it has decided to use the IPCC Tier 1 emission factors, as shown in Table 3 (0.01 lb CH₄/MMBtu HHV and 0.0002 lb N₂O/MMBtu HHV) for all natural gas consumption at the facility. The annual emissions are estimated as follows.

Total facility CO₂ emissions:

- $(600 \times 10^6 \text{ ft}^3 \text{ gas/y}) \times (1050 \times 10^{-6} \text{ MMBtu HHV/ft}^3) = 6.30 \times 10^5 \text{ MMBtu HHV/y}$
- $(6.30 \times 10^5 \text{ MMBtu HHV/y}) \times (117 \text{ lb CO}_2/\text{MMBtu HHV}) = 7.37 \times 10^7 \text{ lb CO}_2/\text{y}$
 $= 3.69 \times 10^4 \text{ ton CO}_2/\text{y}$
- $(36,900 \text{ ton CO}_2/\text{y}) / (1.1023 \text{ short ton/tonne}) = 36,900 \text{ tonne CO}_2/\text{y}$

Total facility CH₄ emissions:

- $(6.30 \times 10^5 \text{ MMBtu HHV/y}) \times (0.01 \text{ lb CH}_4/\text{MMBtu HHV}) = 6300 \text{ lb CH}_4/\text{y}$
 $= 3.15 \text{ ton CH}_4/\text{y}$

Using the IPCC GWP of 21, this is equal to 66.2 ton CO₂-equiv/y

- $(66.2 \text{ ton CO}_2\text{-equiv/y}) / (1.1023 \text{ short ton/tonne}) = 60.0 \text{ tonne CO}_2\text{-equiv/y}$

Total facility N₂O emissions

- $(6.30 \times 10^5 \text{ MMBtu HHV/y}) \times (0.0002 \text{ lb N}_2\text{O/MMBtu HHV}) = 126 \text{ lb N}_2\text{O/y}$
 $= 0.063 \text{ ton N}_2\text{O/y}$

Using the IPCC GWP of 310, this is equal to 19.5 ton CO₂-equiv/y

- $(19.5 \text{ ton CO}_2\text{-equiv/y}) / (1.1023 \text{ short ton/tonne}) = 17.7 \text{ tonne CO}_2\text{-equiv/y}$

Total GHG emissions = 33,400 + 60.0 + 17.7 = 33,500 tonne CO₂-equiv/y

On a CO₂-equivalents basis, combined CH₄ and N₂O emissions are about 0.1% of CO₂ emissions. CH₄ and N₂O emissions would be very small even if the emission factors were several times larger than those used in the calculations. Because of this, the company might decide against including CH₄ and N₂O estimates in the results, and instead indicate that the estimates demonstrate that the CH₄ and N₂O emissions are not material to the results of the inventory because they are less than 0.1% of CO₂ emissions.

Example Calculation J2: CO₂, CH₄, and N₂O emissions from a large dry-bottom, wall fired boiler burning pulverized bituminous coal.

The boiler produces 770,000 lb steam per hour (about 350,000 kg/hr). Over a year's time, the company's records indicate that the boiler consumed 370,000 short tons (336,000 Mg) of coal having a higher heating value, on average, of 13,000 Btu HHV/lb.

Case 1: CO₂ emissions based on carbon content of fuel

The company has information on the carbon content of the coal being burned in the boiler (80.1% carbon, by weight). The company decides that the default IPCC correction for unburned carbon in coal-fired boilers (2% unburned carbon) is appropriate. The company decides to use the Tier 2 IPCC emission factors for CH₄ and N₂O from Table 4. The IPCC Tier 2 emission factors for dry bottom, wall fired boilers burning pulverized bituminous coal are 0.0015 lb CH₄/MMBtu HHV and 0.0035 lb N₂O/MMBtu HHV. The annual emissions of CO₂, CH₄, and N₂O are estimated as follows.

CO₂ emissions:

- $(370,000 \text{ ton/y coal}) \times (0.801 \text{ ton carbon / ton coal}) \times (0.98 \text{ ton carbon burned}) \times (44 \text{ ton CO}_2 / 12 \text{ ton carbon}) = 1,060,000 \text{ ton CO}_2/\text{yr}$ or $1060 \times 10^3 \text{ ton CO}_2/\text{y}$
- $(1060 \times 10^3 \text{ ton CO}_2/\text{y}) / (1.1023 \text{ short ton/tonne}) = 966 \times 10^3 \text{ tonne CO}_2/\text{y}$

CH₄ emissions:

- $370,000 \text{ short tons coal/y} = 740 \times 10^6 \text{ lb/y}$
- $(740 \times 10^6 \text{ lb/y}) \times (13,000 \text{ Btu HHV/lb}) = 9.62 \times 10^{12} \text{ Btu HHV/y}$
 $= 9.62 \times 10^6 \text{ MMBtu HHV/y}$
- $(9.62 \times 10^6 \text{ MMBtu HHV/y}) \times (0.0015 \text{ lb CH}_4/\text{MMBtu HHV})$
 $= 14.4 \times 10^3 \text{ lb CH}_4/\text{y}$ or $7.22 \text{ ton CH}_4/\text{y}$

Using the IPCC GWP of 21 for CH₄, this equates to 152 ton CO₂-equiv/y

- $(152 \text{ ton CO}_2\text{-equiv/y}) / (1.1023 \text{ short ton/tonne}) = 137 \text{ tonne CO}_2\text{-equiv/y}$

N₂O emissions:

- $\text{N}_2\text{O emissions} = (9.62 \times 10^6 \text{ MMBtu HHV/y}) \times (0.0035 \text{ lb N}_2\text{O/MMBtu HHV})$
 $= 16.8 \text{ ton N}_2\text{O/y}$

Using the IPCC GWP of 310 for N₂O, is to 5,220 ton CO₂-equiv/y

- $(5,220 \text{ ton CO}_2\text{-equiv/y}) / (1.1023 \text{ short ton/tonne}) = 4730 \text{ tonne CO}_2\text{-equiv/y}$

Total GHG emissions = $966,000 + 137 + 4,730 = 971,000 \text{ tonne CO}_2\text{-equiv/y}$

Compared to its CO₂ emissions, emissions of CH₄ and N₂O from this boiler are very small.

CO₂ emissions = 966,000 tonne CO₂/y

CH₄ emissions = 137 tonne CO₂-equiv/y or 0.014% of CO₂ emissions

N₂O emissions = 4730 tonne CO₂-equiv/y or about 0.5% of CO₂ emissions

Case 2: CO₂ emissions based on emission factors

In this case the company does not have information on the carbon content of the coal being burned in the boiler. The IPCC default Tier 1 emission factor for CO₂ is 209 lb CO₂/MMBtu HHV. The company decides that the default IPCC correction for unburned carbon in coal-fired boilers (2% unburned carbon) is appropriate.

CO₂ emissions:

- 370,000 short tons coal/y = 740×10^6 lb/y
- $(740 \times 10^6 \text{ lb/y}) \times (13,000 \text{ Btu HHV/lb}) = 9.62 \times 10^{12} \text{ Btu HHV/y}$
= 9.62×10^6 MMBtu HHV/y
- uncorrected CO₂ emissions = $(9.62 \times 10^6 \text{ MMBtu HHV/y}) \times (209 \text{ lb CO}_2 / \text{MMBtu HHV})$
= $2.01 \times 10^9 \text{ lb CO}_2/\text{y} = 1,010 \times 10^3 \text{ ton CO}_2/\text{y}$
- CO₂ emissions corrected for 2% unburned carbon = $985 \times 10^3 \text{ ton CO}_2/\text{y}$
- $(985 \times 10^3 \text{ ton CO}_2/\text{y}) / (1.1023 \text{ short ton/tonne}) = 894 \times 10^3 \text{ tonne CO}_2/\text{y}$

Methane and nitrous oxide emissions are calculated as in Case 1.

CO₂ emissions = 894,000 tonne CO₂/y

CH₄ emissions = 137 tonne CO₂-equiv/y or 0.015% of CO₂ emissions

N₂O emissions = 4,730 tonne CO₂-equiv/y or about 0.5% of CO₂ emissions

As in the previous example, this comparison suggests that it may be relatively simple for many companies to document that emissions of CH₄ and N₂O from fossil fuel-fired boilers are not material to the results of their inventory.

Example Calculation J3: Manufacturing facility with a combination fuel boiler burning bark and oil.

A manufacturing facility has a 550,000 lb steam/hr circulating fluidized bed (CFB) bark boiler. In a year, the boiler burns approximately 6.5×10^6 MMBtu LHV of bark and 0.76×10^6 MMBtu LHV of residual fuel oil. Because the boiler receives supplemental fossil fuel, it is recommended to estimate the CO₂ from the fossil fuel use and the CH₄ and N₂O emissions based on the total firing rate. The plant decides to use the IPCC emission factor for residual oil (169 lb CO₂/MMBtu HHV, after correcting for 1% unoxidized carbon) and to estimate CH₄ and N₂O emissions based on the total firing rate and the emission factors developed by Fortum on CFB boilers. The average emission factors found by Fortum, shown in Table 5, are 0.002 lb CH₄/MMBtu HHV and 0.019 lb N₂O/MMBtu HHV.

CO₂ emissions from fossil fuel:

- for fuel oil LHV is 0.95 times HHV (Section 4.3.2)
- $(0.76 \times 10^6 \text{ MMBtu LHV/y}) / (0.95 \text{ MMBtu LHV/MMBtu HHV})$
 $= 0.80 \times 10^6 \text{ MMBtu HHV}$
- $(0.80 \times 10^6 \text{ MMBtu HHV/y}) \times (169 \text{ lb CO}_2/\text{MMBtu HHV}) = 1.35 \times 10^8 \text{ lb CO}_2/\text{y}$
 $= 67.6 \times 10^3 \text{ ton CO}_2/\text{y}$
- $(67,600 \text{ ton CO}_2/\text{yr}) / (1.1023 \text{ short ton/tonne}) = 61,300 \text{ tonne CO}_2/\text{y}$

CH₄ emissions:

- total heat input = $(6.5 \times 10^6 \text{ MMBtu LHV/y}) + (0.76 \times 10^6 \text{ GJ LHV/y})$
 $= 7.3 \times 10^6 \text{ MMBtu LHV/y}$
- for bark and fuel oil LHV is 0.95 times HHV (Section 4.3.2)
- $(7.3 \times 10^6 \text{ MMBtu LHV/y}) / (0.95 \text{ MMBtu LHV/MMBtu HHV})$
 $= 7.6 \times 10^6 \text{ MMBtu HHV/y}$
- $(7.6 \times 10^6 \text{ MMBtu HHV/y}) \times (0.002 \text{ lb CH}_4/\text{MMBtu HHV}) = 15,300 \text{ lb CH}_4/\text{y}$
 $= 7.6 \text{ ton CH}_4/\text{y}$

Using the IPCC warming potential of 21, this equates to 160 ton CO₂-equiv/y

- $(160 \text{ ton CO}_2\text{-equiv/y}) / (1.1023 \text{ short ton/tonne}) = 146 \text{ tonne CO}_2\text{-equiv/y}$

N₂O emissions:

- total heat input = $7.6 \times 10^6 \text{ MMBtu HHV/y}$
- $(7.6 \times 10^6 \text{ MMBtu HHV/y}) \times (0.019 \text{ lb N}_2\text{O/MMBtu HHV}) = 145,00 \text{ lb N}_2\text{O/y}$
 $= 72.6 \text{ ton N}_2\text{O/y}$

Using the IPCC warming potential of 310, this equates to 22,500 ton CO₂-equiv/y

- $(22,500 \text{ ton CO}_2\text{-equiv/y}) / (1.1023 \text{ short ton/tonne}) = 20,400 \text{ tonne CO}_2\text{-equiv/y}$

Total CO₂-equivalents emitted = $61,300 + 146 + 20,400 = 81,800 \text{ tonne CO}_2\text{-equiv/y}$

Example calculation J4: Manufacturing plant purchasing electrical power.

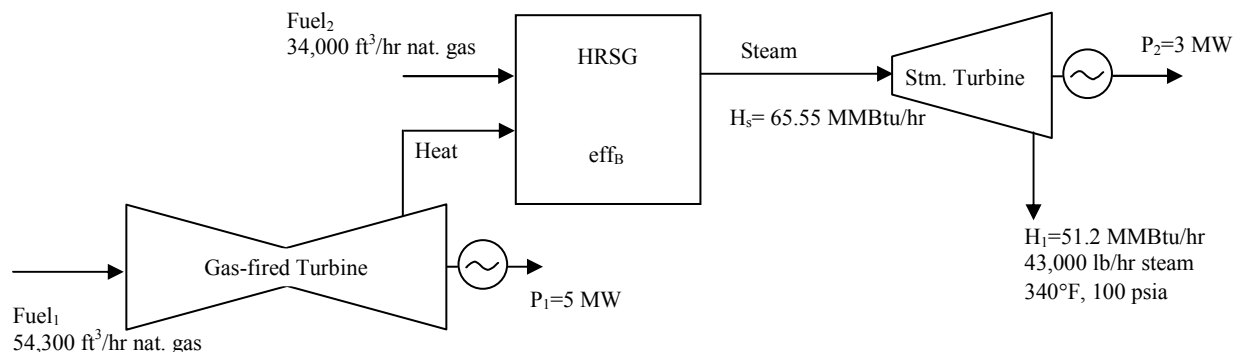
A plant in California purchases 83,300 MWh of electrical power in a year's time. The USEPA's egrid database shows an average emission factor for purchased power in California of 477.99 lb CO₂*/MWh (see Annex C). The indirect emissions associated with the purchased power are estimated as follows.

- $(83.3 \times 10^3 \text{ MWh/y}) \times (477.99 \text{ lb CO}_2/\text{MWh}) = 39.8 \times 10^6 \text{ lb CO}_2/\text{y}$
= 19,900 ton CO₂/y
- $(19,900 \text{ ton CO}_2/\text{y}) / (1.1023 \text{ short ton/tonne}) = 18,100 \text{ tonne CO}_2/\text{y}$

* Emission factor for California is for CO₂ only, not CO₂-equiv

Example Calculation J5: Allocating CHP emissions to three output streams – simplified efficiency method with WRI/WBCSD recommended default efficiency factors.

A manufacturing plant has the CHP system shown in the figure, but it is lacking (or chooses not to use) detailed energy balance information. Instead, the company chooses to use the simplified efficiency method and the efficiencies recommended herein: 0.35 for power generation and 0.8 for steam generation.



Using these assumed efficiencies, emissions can be allocated among the three outputs of the CHP system as follows (using a basis of one hour of operation):

Total system emissions:

Fuel₁:

$$\text{CO}_2 = (54,300 \text{ ft}^3/\text{hr}) \times (1050 \text{ Btu HHV}/\text{ft}^3) \times (1/10^6) \times (117 \text{ lb CO}_2/\text{MMBtu HHV})$$

$$= 6670 \text{ lb CO}_2/\text{hr}$$

$$\text{CH}_4 = (54,300 \text{ ft}^3/\text{hr}) \times (1050 \text{ Btu HHV}/\text{ft}^3) \times (1/10^6) \times (0.001 \text{ lb CH}_4/\text{MMBtu HHV})$$

$$\times (21 \text{ CO}_2\text{-equiv}/\text{CH}_4) = 1.20 \text{ lb CO}_2\text{-equiv}/\text{hr}$$

$$\text{N}_2\text{O} = (54,300 \text{ m}^3/\text{hr}) \times (1050 \text{ Btu HHV}/\text{ft}^3) \times (1/10^6) \times (0.0002 \text{ lb N}_2\text{O}/\text{MMBtu HHV})$$

$$\times (310 \text{ CO}_2\text{-equiv}/\text{N}_2\text{O}) = 3.53 \text{ lb CO}_2\text{-equiv}/\text{hr}$$

$$\text{Total Fuel}_1 \text{ emissions} = 6675 \text{ lb CO}_2\text{-equiv}/\text{hr}$$

Fuel₂:

$$\text{CO}_2 = (34,000 \text{ ft}^3/\text{hr}) \times (1050 \text{ Btu HHV}/\text{ft}^3) \times (1/10^6) \times (117 \text{ kg CO}_2/\text{MMBtu HHV})$$

$$= 4177 \text{ lb CO}_2/\text{hr}$$

$$\text{CH}_4 = (34,000 \text{ ft}^3/\text{hr}) \times (1050 \text{ Btu HHV}/\text{ft}^3) \times (1/10^6) \times (0.0029 \text{ lb CH}_4/\text{MMBtu HHV})$$

$$\times (21 \text{ CO}_2\text{-equiv}/\text{CH}_4) = 2.17 \text{ lb CO}_2\text{-equiv}/\text{hr}$$

$$\text{N}_2\text{O} = (34,000 \text{ ft}^3/\text{hr}) \times (1050 \text{ Btu HHV}/\text{ft}^3) \times (1/10^6) \times (0.0002 \text{ lb N}_2\text{O}/\text{MMBtu HHV})$$

$$\times (310 \text{ CO}_2\text{-equiv}/\text{N}_2\text{O}) = 2.21 \text{ kg CO}_2\text{-equiv}/\text{hr}$$

$$\text{Total Fuel}_2 \text{ emissions} = 4181 \text{ lb CO}_2\text{-equiv}/\text{hr}$$

$$\text{Total CHP system emissions} = 6675 + 4181 = 10,856 \text{ lb CO}_2\text{-equiv}/\text{hr}$$

$$\text{Total system power output} = P_1 + P_2 = 8 \text{ MW}$$

$$R_{eff} = \frac{0.8}{0.35} = 2.3$$

$$E_H = \left\{ \frac{15MW}{15MW + (8MW \times 2.3)} \right\} \times 10,856 lbCO_2 eq = 4875 lbCO_2 eq = 20,477 \text{ ton CO}_2 \text{ equiv/y at 350 d/y operation}$$

$$(20,477 \text{ ton CO}_2 \text{ equiv/y}) / (1.1023 \text{ short ton/tonne}) = 18,600 \text{ tonne CO}_2 \text{ equiv/y at 350 d/y operation}$$

$$E_P = 10,856 lbCO_2 eq - 4875 lbCO_2 eq = 5981 lbCO_2 eq = 25,120 \text{ ton CO}_2 \text{ equiv/yr at 350 d/y operation}$$

$$(25,120 \text{ ton CO}_2 \text{ equiv/y}) / (1.1023 \text{ short ton/tonne}) = 22,800 \text{ tonne CO}_2 \text{ equiv/y at 350 d/y operation}$$

Using the simplified efficiency method with default power and steam efficiency factors, therefore, the emissions from the CHP system are allocated to the output streams in the following percentages:

- Percentage of CHP emissions to heat output = $100 \times 4875 / 10,856 = 44.9\%$
- Percentage of CHP emissions to power output = $100 \times 5981 / 10,856 = 55.1\%$

These percentages can be used to allocate all GHG emissions from the CHP system. Emission factors can be developed for the energy outputs:

- Emission factor for CHP heat output = $(4875 \text{ lb CO}_2\text{-equiv/hr}) / 51.2 \text{ MMBtu} = 95.2 \text{ lb CO}_2\text{-equiv/MMBtu}$
- Emission factor for CHP power output = $(5981 \text{ CO}_2\text{-equiv/hr}) / 8 \text{ MW} = 748 \text{ lb CO}_2\text{-equiv/MWh}$

Example calculation J6: GHG emissions from on-site vehicles and equipment.

Based on purchasing records, a company estimates the amounts of fuel purchased over a year to fuel on-site vehicles and equipment. It applies the largest of the emission factors shown in Table 1 and estimates that the emissions are much less than 0.5% of the plant's emissions. Rather than trying to develop a more accurate estimate, the company decides to report in the results only that the emissions from this source are non-material because they represent less than 0.5% of the total emissions.

Example calculation J7: GHG emissions from a company's forestry operations and wood transport fleet.

A company's fuel purchasing records indicate that, in a year, the following amounts of fuel are consumed by the company's woodlands operations and its fleet of trucks used to transport wood to the manufacturing plant:

- Gasoline = 2,600 gal – The company estimates that approximately 90% of this is used in 4-stroke engines and 10% is used in 2-stroke engines in forestry equipment.
- Diesel = 53,000 gal

The heat content of the gasoline is estimated to be 0.122 MMBtu LHV/gal and the heat content of the diesel fuel is 0.136 MMBtu LHV/gal.

The company decides to use the CO₂-equivalent emission factors in Table 7 to estimate emissions.

- Gasoline used in 4-stroke engines = 2,600 gal/y x 0.9 = 2,340 gal/y
- (2,340 gal/y) x (0.122 MMBtu LHV/gal) = 285 MMBtu LHV/y
- for gasoline LHV is 0.95 times HHV (Section 4.3.2)
- (285 MMBtu LHV/y) / (0.95 MMBtu LHV/MMBtu HHV) = 301 MMBtu HHV/y
- (301 MMBtu HHV/y) x (155 lb CO₂-equiv/MMBtu HHV) = 46,600 lb CO₂-equiv/y = 23.3 ton CO₂-equiv/y
- (23.3 ton CO₂-equiv/y) / (1.1023 short ton/tonne) = 21.1 tonne CO₂ equiv/y

- Gasoline used in 2-stroke engines = 2,600 gal/y x 0.1 = 260 gal/y
- (260 gal/y) x (0.122 GJ LHV/liter) = 31.7 MMBtu LHV/y
- for gasoline LHV is 0.95 times HHV (Section 4.3.2)
- (31.7 MMBtu LHV/y) / (0.95 MMBtu LHV/MMBtu HHV) = 33.4 MMBtu HHV/y
- (33.4 MMBtu HHV/y) x (158 lb CO₂-equiv/MMBtu HHV) = 5276 lb CO₂-equiv/y = 2.64 ton CO₂-equiv/y
- (2.64 ton CO₂-equiv/y) / (1.1023 short ton/tonne) = 2.39 tonne CO₂-equiv/y

- Diesel used = 53,000 gal/y
- (53,000 gal/y) x (0.136 MMBtu LHV/gal) = 7210 MMBtu LHV/y
- for diesel LHV is 0.95 times HHV (Section 4.3.2)
- (7210 MMBtu LHV/y) / (0.95 MMBtu LHV/MMBtu HHV) = 7590 MMBtu HHV/y
- (7590 MMBtu HHV/y) x (183 lb CO₂-equiv/MMBtu HHV) = 1.39 x 10⁶ lb CO₂-equiv/y = 694 ton CO₂-equiv/y
- (694 ton CO₂-equiv/y) / (1.1023 short ton/tonne) = 630 tonne CO₂-equiv/y

Total GHG emissions from company-owned forestry operations and wood trucks

- 21.1 + 2.39 + 630 = 653 tonne CO₂-equiv/y

Example Calculation J8: Emissions from a company-owned landfill with a modern low-permeability cap and gas collection system. The collected gas is burned.

Measurements have been made on a landfill gas collection system. The system is collecting 29.0 million standard ft³/y and the gas is 47% methane by volume. The plant has no site-specific data on the efficiency of the gas collection system, so it uses the recommended default value of 75%. It also uses the default assumption that 10% of the uncollected gas is oxidized before escaping to the atmosphere.

- methane collected = $(29.0 \times 10^6 \text{ ft}^3/\text{y}) \times (0.47) = 13.6 \times 10^6 \text{ ft}^3/\text{y}$
- methane generated = $(13.6 \times 10^6 \text{ ft}^3/\text{y}) / (0.75) = 18.2 \times 10^6 \text{ ft}^3/\text{y}$
- methane released = $(18.2 \times 10^6 - 13.6 \times 10^6 \text{ ft}^3/\text{y}) \times (1 - 0.1) = 4.09 \times 10^6 \text{ ft}^3/\text{y}$
- methane released = $(4.09 \times 10^6 \text{ ft}^3/\text{y}) / (385 \text{ ft}^3/\text{lb-mole}) = 10,620 \text{ lb-mole/y}$
- methane released = $(10,620 \text{ lb-mole/y}) \times (16 \text{ lb/lb-mole}) = 1.70 \times 10^5 \text{ lb/y}$
= 85.0 ton CH₄/y

Using the IPCC GWP (21), this is equal to 1780 ton CO₂-equiv/y

- $(1780 \text{ ton CO}_2\text{-equiv/y}) / (1.1023 \text{ short ton/tonne}) = 1620 \text{ tonne CO}_2\text{-equiv/y}$

Example calculation J9: Emissions from 20 year old landfill receiving wood products plant log yard debris and boiler ash. The landfill does not have a gas collection system.

A plant landfills 80 ton per day of solid waste composed primarily of logyard debris, boiler ash, and other miscellaneous waste typical of a wood products manufacturing plant. The plant generates waste 350 days a year. The landfill has been in use for 20 years and is still active. The landfill does not have a gas recovery system. The plant uses the default values for k and L_0 shown in Table 8 ($100 \text{ m}^3/\text{Mg}$ for L_0 and 0.03 y^{-1} for k).

The plant estimates that approximately 25 tons of the daily landfill deposit is comprised of inert materials (e.g., concrete, ash). Therefore the daily deposition rate is adjusted to 55 tons per day.

$$R = (55 \text{ ton/d}) \times (350 \text{ d/y}) \times (907.2 \text{ kg/ton}) / (1 \times 10^3 \text{ kg/tonne}) = 17,460 \text{ tonne/y}$$

$$L_0 = 100 \text{ m}^3/\text{tonne}$$

$$k = 0.03/\text{y}$$

$$C = 0 \text{ y}$$

$$T = 20 \text{ y}$$

- methane generated (m^3/y) = $(17,460 \text{ tonne/y}) \times (100 \text{ m}^3 \text{ CH}_4/\text{tonne}) \times (e^{-0.03 \times 0} - e^{-0.03 \times 20})$
= $788,000 \text{ m}^3 \text{ CH}_4/\text{y}$
- density of methane (0°C and 1 atm. pressure) = 0.7167 kg/m^3 (Green 1984)
- methane generated (kg/y) = $(788,000 \text{ m}^3/\text{y}) \times (0.7167 \text{ kg/m}^3) = 565,000 \text{ kg CH}_4/\text{y}$
= $565 \text{ tonne CH}_4/\text{y}$
- assume 10% oxidation in landfill cover
- methane released = $(565 \text{ tonne CH}_4/\text{y}) \times (1 - 0.1) = 508 \text{ tonne CH}_4/\text{y}$ released

Using the IPCC GWP (21), this equals $10,700 \text{ tonne CO}_2\text{-equiv/y}$

Note that the Table 1 emission factor would have yielded an estimate of $55 \text{ ton/d} \times 350 \text{ d/y} \times 907.2 \text{ kg/ton} \times 3.5 \text{ kg CO}_2\text{-equiv/kg} = 61,120,000 \text{ kg/y} = 61,120 \text{ tonne CO}_2\text{-equiv/y}$, over five times the estimate developed using the more refined approach.

Example calculation J10: Wood products plant with anaerobic treatment but no gas recovery.

A wood products manufacturing plant uses an anaerobic treatment plant to treat wastewater containing 22,000 lb COD/d. The plant generates wastewater 300 days per year. The IPCC default value for CH₄ generation from anaerobic treatment systems is 0.25 lb CH₄/lb COD in the feed. The CH₄ emissions are calculated as follows.

- amount of organic carbon = 22,000 lb/d x 300 d/y = 6,600,000 lb COD/y
- CH₄ generated = 6,600,000 lb COD/y x 0.25 lb CH₄/lb COD = 1,650,000 lb CH₄/y
= 825 ton CH₄/y

Using the IPCC GWP (21), this equals 17,325 ton CO₂-equiv/y

- (17325 ton CO₂-equiv/y) / (1.1023 short ton/tonne) = 15,700 tonne CO₂-equiv/y

Example Calculation J11: Combination boiler providing 200,000 lb/hr steam from wood residuals and natural gas.

A plywood plant operates a boiler that provides an average of 200,000 lb/hr of steam (600° F, 400 psia). The boiler operates 24 hr/d, 350d/yr. The plant meters the natural gas consumption of the boiler, but not the firing rate of wood residual fuel. The efficiency of the boiler in producing steam from wood fuel is approximately 67%, and in producing steam from natural gas fuel is approximately 81%. The boiler consumed $790 \times 10^6 \text{ ft}^3$ of gas in a year's time. The emissions can be estimated as follows:

Steam Production: 200,000 lb/hr
600° F, 400 psia, 1307 Btu/lb

$$\left(\frac{200,000 \text{ lb}}{\text{hr}} \right) \times \left(\frac{24 \text{ hr}}{\text{d}} \right) \times \left(\frac{350 \text{ d}}{\text{yr}} \right) \times \left(\frac{1307 \text{ Btu}}{\text{lb}} \right) = 2,200,000 \text{ MMBtu steam/yr}$$

Natural gas consumption:

$$\left(\frac{790 \times 10^6 \text{ ft}^3}{\text{yr}} \right) \times \left(\frac{1013 \text{ Btu HHV}}{\text{ft}^3 \text{ gas}} \right) \times \left(\frac{1 \text{ MMBtu}}{10^6 \text{ Btu}} \right) = 800,000 \text{ MMBtu HHV gas/yr}$$

Wood fuel consumption:

$$2,200,000 \text{ MMBtu steam} = \left(\frac{0.81 \text{ MMBtu Steam}}{1 \text{ MMBtu HHV gas}} \right) \times 800,000 \text{ MMBtu HHV gas} \\ + \left(\frac{0.67 \text{ MMBtu Steam}}{1 \text{ MMBtu HHV Wood}} \right) \times \text{amount of wood fuel}$$

$$\text{amount of wood fuel} = (2,200,000 - 648,000 \text{ MMBtu Steam}) \times \left(\frac{1 \text{ MMBtu HHV Wood}}{0.67 \text{ MMBtu Steam}} \right) \\ = 2,316,000 \text{ MMBtu HHV Wood}$$

Emissions from Natural Gas

CO₂ emissions:

The facility uses the median CO₂ emission factor corrected for unoxidized carbon for natural gas from Table 2.

$$\left(\frac{800,000 \text{ MMBtu HHV}}{\text{yr}} \right) \times \left(\frac{117 \text{ lb CO}_2}{\text{MMBtu HHV}} \right) = 93.6 \times 10^6 \text{ lb CO}_2.$$

The facility uses the IPCC Tier 2 emission factors for CH₄ and N₂O from Table 4.

CH₄ emissions:

$$\left(\frac{800,000 \text{ MMBtu HHV}}{\text{yr}} \right) \times \left(\frac{0.0029 \text{ lb CH}_4}{\text{MMBtu HHV}} \right) = 2320 \text{ lb CH}_4$$

N₂O emissions:

$$\left(\frac{800,000 \text{ MMBtu HHV}}{\text{yr}} \right) \times \left(\frac{0.0002 \text{ lb N}_2\text{O}}{\text{MMBtu HHV}} \right) = 160 \text{ lb N}_2\text{O}$$

Emissions from Wood Fuel

CO₂ emissions:

CO₂ generated from combustion of biomass fuels should not be included in inventory results. However, the plant decides to compute emissions and report separately as supporting information, using the emission factor from Table H1.

$$\left(\frac{2,316,000 \text{ MMBtu HHV}}{\text{yr}} \right) \times \left(\frac{24 \text{ lb CO}_2}{\text{MMBtu HHV}} \right) = 558 \times 10^6 \text{ lb biomass-derived CO}_2/\text{yr}$$

For CH₄ and N₂O, the facility uses the median emission factors for biomass fuels from Table 5.

CH₄ emissions:

$$\left(\frac{2,316,000 \text{ MMBtu HHV}}{\text{yr}} \right) \times \left(\frac{0.027 \text{ lb CH}_4}{\text{MMBtu HHV}} \right) = 62,540 \text{ lb CH}_4/\text{yr}$$

N₂O emissions:

$$\left(\frac{2,316,000 \text{ MMBtu HHV}}{\text{yr}} \right) \times \left(\frac{0.009 \text{ lb N}_2\text{O}}{\text{MMBtu HHV}} \right) = 20,850 \text{ lb N}_2\text{O}/\text{yr}$$

Total GHG emissions expressed as metric tonnes CO₂ equivalents:

$$\left[\left(93.6 \times 10^6 \text{ lb CO}_2 \right) + \left(2320 + 62,540 \text{ lb CH}_4 \right) \times \left(21 \frac{\text{lb CO}_2 \text{ eq.}}{\text{lb CH}_4} \right) + \left(160 + 20,850 \text{ lb N}_2\text{O} \right) \times \left(310 \frac{\text{lb CO}_2 \text{ eq.}}{\text{lb N}_2\text{O}} \right) \right] \\ \times \left(\frac{1 \text{ tonne}}{2205 \text{ lb}} \right) = 46,000 \text{ metric tonnes CO}_2 \text{ eq./yr}$$

Example Calculation J12: Teepee burner combusting wood residuals

A wood products facility operates a teepee burner to burn its wood residuals. The facility estimates that 250 million pounds of residuals were burned in the unit during a year's time. The facility estimates the moisture content of the fuel at 35% (wet basis), and heating value of 18 MMBtu (HHV) per ton (2000 lb) of fuel.

CO₂ emissions:

CO₂ generated from combustion of biomass fuels should not be included in inventory results. However, the plant decides to compute emissions and report separately as supporting information, using the emission factor from Table H1.

$$\begin{aligned} & (250 \times 10^6 \text{ lb wood @ } 35\% H_2O) \times \left(\frac{0.65 \text{ lb wood}}{1 \text{ lb wet wood}} \right) \times \left(\frac{1 \text{ short ton}}{2000 \text{ lb}} \right) \times \left(\frac{18 \text{ MMBtu HHV}}{\text{short ton}} \right) \\ & = 1,460,000 \text{ MMBtu HHV} \\ & (1,460,000 \text{ MMBtu HHV}) \times \left(\frac{241 \text{ lb CO}_2}{\text{MMBtu HHV}} \right) = 352 \times 10^6 \text{ lb biomass-derived CO}_2/\text{yr} \end{aligned}$$

For CH₄ and N₂O, the facility uses the IPCC Tier 1 emission factors from Table 5.

CH₄ emissions:

$$(1,460,000 \text{ MMBtu HHV}) \times \left(\frac{0.07 \text{ lb CH}_4}{\text{MMBtu HHV}} \right) = 102,200 \text{ lb CH}_4/\text{yr}$$

N₂O emissions:

$$(1,460,000 \text{ MMBtu HHV}) \times \left(\frac{0.009 \text{ lb N}_2\text{O}}{\text{MMBtu HHV}} \right) = 13,140 \text{ lb N}_2\text{O}/\text{yr}$$

Total GHG emissions expressed as metric tonnes CO₂ equivalents:

$$\begin{aligned} & \left[(102,200 \text{ lb CH}_4) \times \left(\frac{21 \text{ lb CO}_2 \text{ eq.}}{\text{lb CH}_4} \right) + (13,140 \text{ lb N}_2\text{O}) \times \left(\frac{310 \text{ lb CO}_2 \text{ eq.}}{\text{lb N}_2\text{O}} \right) \right] \times \left(\frac{1 \text{ tonne}}{2205 \text{ lb}} \right) \\ & = 2820 \text{ metric tonnes CO}_2\text{-equiv}/\text{yr} \end{aligned}$$

Example Calculation J13: Estimating emissions based on emission testing results.

A plywood plant operates an RCO to control emissions from veneer dryers. The veneer dryers are direct-fired with natural gas, and the RCO consumes natural gas as well. The facility has access to recent emission source testing results at the inlet and outlet of the RCO, and is interested in calculating methane emissions based on the testing results. The calculated methane emissions will be used to adjust the CO₂ emissions estimated based on emission factors.

The facility operates 24 hr/d, 350 d/yr.

Test Results:

RCO inlet (dryer exhaust):

- Avg. RCO inlet flowrate: 28,084 scfm
- Avg. methane concentration (dry): 49 ppm

RCO exhaust:

- Avg. RCO exhaust flowrate: 29,336 scfm
- Avg. methane concentration (dry): 67 ppm

Avg. natural gas consumption in RCO: 1,000 ft³/hr

Avg. natural gas consumption in veneer dryers: 34,000 ft³/hr

CH₄ emissions based on emissions test results:

RCO inlet:

$$\left(\frac{28,084 \text{ ft}^3}{\text{min}} \right) \times (49 \text{ ppm dry}) \times \left(\frac{1}{10^6} \right) \times \left(\frac{1 \text{ lbmol}}{385 \text{ ft}^3} \right) \times \left(\frac{16 \text{ lb}}{\text{lbmol}} \right) \times \left(\frac{60 \text{ min}}{\text{hr}} \right) \times \left(\frac{24 \text{ hr}}{\text{d}} \right) \times \left(\frac{350 \text{ d}}{\text{yr}} \right)$$
$$= 28,800 \text{ lb CH}_4/\text{yr}$$

RCO exhaust:

$$\left(\frac{29,336 \text{ ft}^3}{\text{min}} \right) \times (67 \text{ ppm dry}) \times \left(\frac{1}{10^6} \right) \times \left(\frac{1 \text{ lbmol}}{385 \text{ ft}^3} \right) \times \left(\frac{16 \text{ lb}}{\text{lbmol}} \right) \times \left(\frac{60 \text{ min}}{\text{hr}} \right) \times \left(\frac{24 \text{ hr}}{\text{d}} \right) \times \left(\frac{350 \text{ d}}{\text{yr}} \right)$$
$$= 41,200 \text{ lb CH}_4/\text{yr}$$

Difference between RCO inlet and exhaust (corresponds to methane emissions contribution of the RCO):

$$41,200 - 28,800 = 12,400 \text{ lb CH}_4/\text{yr}$$

This result indicates that the RCO was not effective in destroying the methane in the dryer exhaust, but rather contributed to total methane emissions.

The facility has estimated CO₂ emissions based on the activity data (fuel consumption) combined with the IPCC Tier I emission factor for natural gas (as listed in Table 2). The facility has decided to adjust this CO₂ emissions estimate based on the results of the

emissions testing, because the emission test results indicate that a portion of the natural gas fuel sent to the dryer and the RCO was not combusted (i.e., not converted to CO₂) but rather was emitted as methane. In other words, the assumption that all fuel sent to the combustion devices was oxidized to CO₂ was incorrect. The adjustment can be made as follows:

CO₂ estimate based on emission factor:

$$\left(1,000 + 34,000 \frac{ft^3}{hr}\right) \times \left(\frac{1013 Btu HHV}{ft^3 gas}\right) \times \left(\frac{1 MMBtu}{10^6 Btu}\right) \times \left(\frac{117 lb CO_2}{MMBtu HHV}\right) \times \left(\frac{24 hr}{d}\right) \times \left(\frac{350 d}{yr}\right) \\ = 34,800,000 lb CO_2/yr$$

The methane emissions corresponding to dryer and RCO fuel which was emitted as unburned methane (41,200 lb per year), computed based on emission testing results, represent approximately 0.3% of the total fuel sent to the combustion device. Since each pound of carbon in the uncombusted fuel (methane) corresponds to one pound of carbon in CO₂ which would have been emitted if the fuel had been oxidized, the CO₂ estimate can be adjusted by subtracting the mass of carbon in unburned CH₄ (converted to an equivalent mass of CO₂) in the RCO exhaust:

$$(34,800,000 lb CO_2 / yr) - (41,200 lb CH_4 / yr) \times \left(\frac{1 lb C}{16 lb CH_4}\right) \times \left(\frac{44 lb CO_2}{1 lb C}\right) \\ = 34,700,000 lb CO_2 / yr$$

The facility is interested in comparing the methane emission estimate based on source test results to an estimate based on fuel consumption and the IPCC Tier 1 methane emission factor from Table 3. The calculation is based on the total natural gas consumption in the veneer dryers and the RCO.

$$\left(1,000 + 34,000 \frac{ft^3}{hr}\right) \times \left(\frac{1013 Btu HHV}{ft^3 gas}\right) \times \left(\frac{1 MMBtu}{10^6 Btu}\right) \times \left(\frac{0.01 lb CH_4}{MMBtu HHV}\right) \times \left(\frac{24 hr}{d}\right) \times \left(\frac{350 d}{yr}\right) \\ = 2,980 lb CH_4/yr$$

The emissions estimate based on source test results (41,200 lb CH₄/yr) is approximately 14 times greater than the estimate based on fuel consumption and the Tier 1 emissions factor (2,980 lb CH₄/yr). This illustrates that:

- (1) uncertainty associated with methane emissions estimates can be high
- (2) some natural gas direct fired combustion devices can emit significant quantities of uncombusted methane, and
- (3) due to low combustion temperatures, RCOs are generally not effective at controlling methane emissions

The source testing did not include analysis of nitrous oxide emissions. Therefore, the facility decided to base nitrous oxide emission estimates on fuel combustion data and IPCC Tier I emission factors. The facility also decided to adjust the activity data (data on fuel consumption in the combustion devices) to account for unburned fuel as indicated by the methane emission test results.

$$\left(\frac{34.8 - \left[0.0412 \times \left(\frac{44}{16} \right) \right]}{34.8} \right) \times \left(1,000 + 34,000 \frac{ft^3}{hr} \right) \times \left(\frac{1013 Btu HHV}{ft^3 gas} \right) \times \left(\frac{1 MMBtu}{10^6 Btu} \right) \times \left(\frac{0.0002 lb N_2O}{MMBtu HHV} \right) \\ \times \left(\frac{24 hr}{d} \right) \times \left(\frac{350 d}{yr} \right) = 59.4 \text{ lb } N_2O/yr$$

Overall GHG emissions expressed as CO₂ equivalents:

$$34,700,000 \text{ lb CO}_2/\text{yr} + (41,200 \text{ lb CH}_4/\text{yr}) \times (21) + (59.4 \text{ lb N}_2\text{O}/\text{yr}) \times (310) \\ = 35,600,000 \text{ lb CO}_2\text{-equiv}/\text{yr}$$

ANNEX K

CONVERSION FACTORS

Mass			
1 pound (lb)	453.6 grams (g)	0.4536 kilograms (kg)	0.0004536 metric tonnes
1 kilogram (kg)	2.205 pounds (lb)		
1 short ton (ton)	2,000 pounds (lb)	907.2 kilograms (kg)	
1 metric tonne	2,205 pounds (lb)	1,000 kilograms (kg)	1.1023 short tons (tons)

Volume			
1 cubic foot (ft ³)	7.4805 gallons (gal)	0.1781 barrel (bbl)	
1 cubic foot (ft ³)	28.32 liters (L)	0.02832 cubic meters (m ³)	
1 gallon (gal)	0.0238 barrel (bbl)	3.785 liters (L)	0.003785 cubic meters (m ³)
1 barrel (bbl)	42 gallons (gal)	158.99 liters (L)	0.1589 cubic meters (m ³)
1 litre (L)	0.001 cubic meters (m ³)	0.2642 gallons (gal)	
1 cubic meter (m ³)	6.2897 barrels (bbl)	264.2 gallons (gal)	1,000 liters (L)

Energy			
1 kilowatt hour (kWh)	3412 Btu (btu)	3,600 kilojoules (KJ)	
1 megajoule (MJ)	0.001 gigajoules (GJ)		
1 gigajoule (GJ)	0.9478 million Btu (million btu)	277.8 kilowatt hours (kWh)	
1 Btu (btu)	1,055 joules (J)		
1 million Btu (million btu)	1.055 gigajoules (GJ)	293 kilowatt hours (kWh)	
1 therm (therm)	100,000 btu	0.1055 gigajoules (GJ)	29.3 kilowatt hours (kWh)

Other			
kilo	1,000		
mega	1,000,000		
giga	1,000,000,000		
tera	1,000,000,000,000		
1 psi	0.06895 bar		
1 kgf / cm ³ (tech atm)	0.9807 bar		
1 atmosphere (atm)	1.01325 bar	101.325 kilo pascals	14.696 pounds per square inch (psia)
1 mile (statue)	1.609 kilometers		
1 metric tonne CH ₄	21 metric tonnes CO ₂ -equivalent		
1 metric tonne N ₂ O	310 metric tonnes CO ₂ -equivalent		
1 metric tonne carbon	3.664 metric tonnes CO ₂		

ANNEX L

REFERENCES FOR ANNEXES A THROUGH K

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