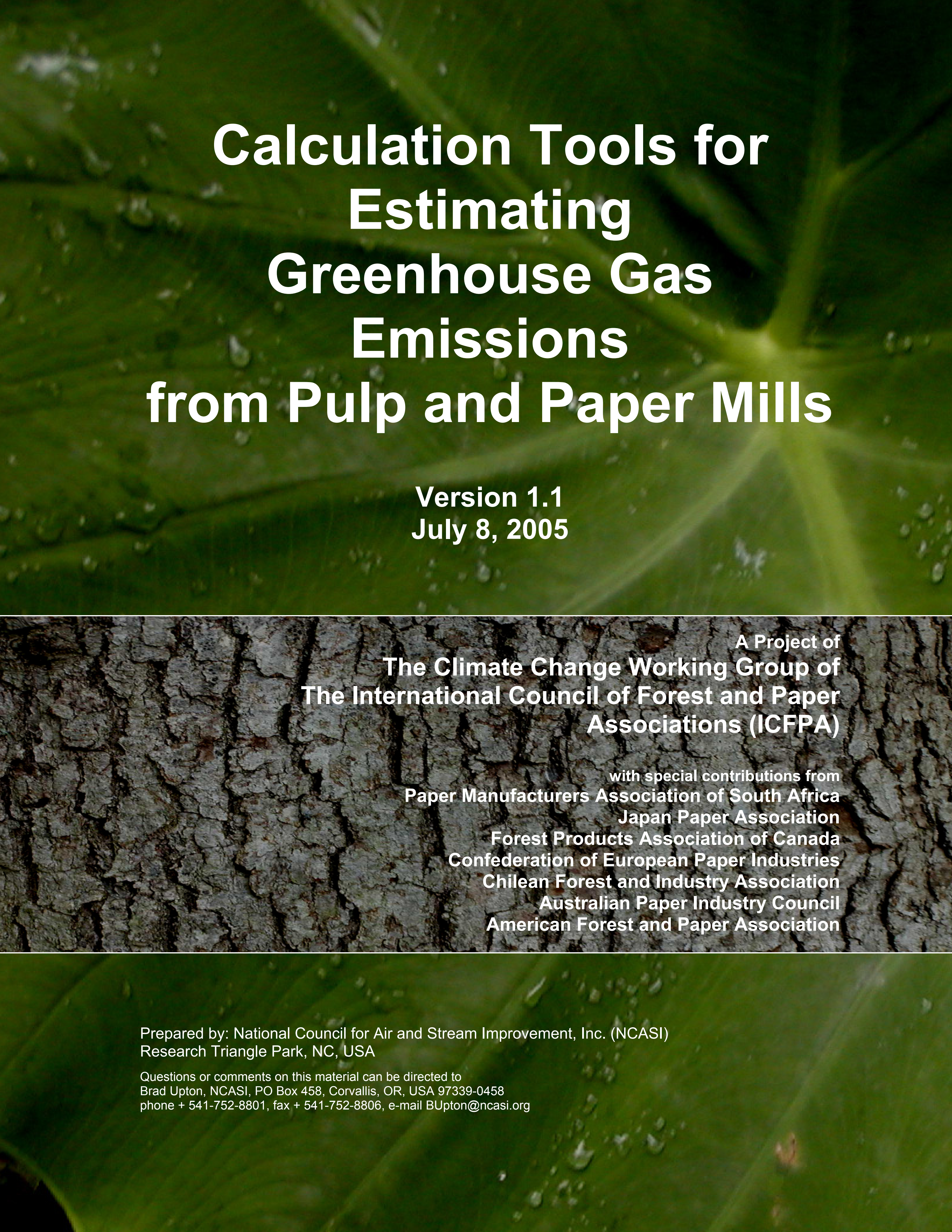

Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills

Version 1.1
July 8, 2005

A Project of
**The Climate Change Working Group of
The International Council of Forest and Paper Associations (ICFPA)**

with special contributions from
**Paper Manufacturers Association of South Africa
Japan Paper Association
Forest Products Association of Canada
Confederation of European Paper Industries
Chilean Forest and Industry Association
Australian Paper Industry Council
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CALCULATION TOOLS FOR ESTIMATING GREENHOUSE GAS EMISSIONS FROM PULP AND PAPER MILLS – Version 1.1

EXECUTIVE SUMMARY

This report contains Version 1.1 of the *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills*, developed for the International Council of Forests and Paper Associations by the National Council for Air and Stream Improvement, Inc. (NCASI). The differences between this version of the tools and Version 1.0, issued in 2001, are described in Annex G to this report. It is intended that these industry-specific tools be used in conjunction with a greenhouse gas (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 Environmental Protection Agency (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 pulp and paper mills 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 CO_2 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 do so it can report them separately. Companies that wish to comply with the WRI/WBCSD GHG Protocol should include these biomass combustion CO_2 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 CO_2 emissions from fossil fuel combustion from emissions of CO_2 from biomass combustion. Methane and nitrous oxide emissions from combustion processes, both fossil fuel and biomass, are estimated using fuel-based emission factors and activity data. Methods are presented for estimating the fossil-CO_2, methane, and nitrous oxide emissions from kraft mill lime kilns and calciners. 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.

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 corporate inventories that include all direct emission sources from within the organizational boundaries–e.g., company-owned truck fleets–as well as indirect emission sources outside the organizational boundaries–e.g., emissions from electricity, heat, and steam purchased and consumed–and on-site pulp and paper making operations outside the organizational boundaries. It is understood, however, that companies will include indirect emission sources that are best suited to the objectives of the inventory. For most mills, 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 12.

For inventories which consider CO_2 emissions only (i.e., CH_4 and N_2O 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 CO_2 emission factors. In certain situations, CH_4 and N_2O 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 report direct emissions (those from sources owned or controlled by the company) separately 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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1.0 INTRODUCTION

Responding to the need for improved methods for estimating greenhouse gas (GHG) emissions from pulp and paper mills, in 2001 the International Council of Forest and Paper Associations (ICFPA) agreed to develop international tools to:
- enable harmonized collection of credible, transparent, and comparable data worldwide
- 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

To accomplish this, the ICFPA Climate Change Working Group retained the research institute National Council for Air and Stream Improvement, Inc. (NCASI) to review existing GHG protocols and assist the industry in developing calculation tools for estimating GHG emissions.

The results of that effort are contained in this report. Version 1.0 of these Calculation Tools was issued in December 2001. Annex G presents an overview of the revisions made in the preparation of this version of the Calculation Tools. 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.

This material encompasses only manufacturing-related emissions from pulp and paper production. Issues related to carbon sinks or forest sequestration are not addressed.[1]

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 Environmental Protection Agency (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

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[1] IPCC has developed methods that countries are using to characterize sequestration (IPCC 1997a, b, c, 2000b, 2003), 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.

for verifying the results–issues beyond the scope of the industry-specific calculation tools in this report. Georgia-Pacific 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 cannot be economically recycled provide one source of biomass fuels.

The pulp and paper 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 pulp and paper industries in some countries derive more than half their energy from CHP systems.

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 2001, 2004a)
- the PEW Center on Global Climate Change (Loreti, Wescott, and Isenberg 2000; Loreti, Foster, and Obbagy 2001)
- the United States Environmental Protection Agency (USEPA 2003)
- Canada's Climate Change Voluntary Challenge and Registry (VCR 2004)

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 pulp and paper 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.

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 pulp and paper mill 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.

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 2001, 2004a). 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 boundaries and organizational boundaries. The organizational boundaries reflect the ownership or control of the company's operations and legal structure. The GHG Protocol (WRI 2004a) 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 2004a).

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 2001, 2004a):

- ***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 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 2004a).

Emissions from operations that are not part of the normal pulp and papermaking 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).

4.1.3 *Estimating Emissions*

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

- CO_2 emissions from stationary fossil fuel combustion
- CH_4 and N_2O emissions from fossil fuel-fired units, recovery furnaces, biomass-fired boilers, and lime kilns
- CO_2 emissions from make-up $CaCO_3$ or Na_2CO_3 used in the pulp mill
- CO_2, CH_4, and N_2O emissions from transportation and mobile sources
- CH_4 emissions attributable to mill wastes in landfills and anaerobic waste treatment operations
- emissions from mobile sources (e.g., company-owned harvesting equipment and company-owned truck fleets)
- fossil fuel-derived CO_2 exported to satellite precipitated calcium carbonate (PCC) plants
- imports of CO_2 (e.g., for pH neutralization)
- 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 pulp and paper mills allow companies to estimate CO_2 releases derived from biomass, but this carbon is not included in GHG emission totals (i.e., it is tracked separately). 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 that is consistent with that used in national inventories, wherein CO_2 emissions from the combustion of biomass are included for informational purposes but are not included in national emission totals. Methods for estimating releases of biomass-derived CO_2 are contained in Annex E.

Although not addressed in these calculation tools, fuel gas system piping may have methane equipment leaks (e.g., piping associated with a natural gas boiler). 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. In Section 16 of this report an example format for reporting inventory results provides the company an opportunity to convey transparent and disaggregated information (however, the company may choose to report using a different format). Annex E provides an example format for reporting additional information on emissions of biomass-derived CO_2.

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). For most mills, 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 usually have excellent records of the types and amounts of fossil fuel being consumed, and CO_2 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 mills, however, because the largest sources of GHGs from most pulp and paper mills, 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. The SI (metric) system is used throughout this report. Annexes contain emission factors and other parameters in the units preferred by the authority or country responsible for the information. 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, and can be used to convert a quantity of non-CO_2 greenhouse gas into an amount of CO_2 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 CH_4 is 21 so, from the standpoint of potential global warming, every gram of CH_4 is equivalent to 21 grams of CO_2. The GWP for N_2O is 310.[2] 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 CO_2, the estimate is said to be in CO_2-equivalents, sometimes abbreviated as CO_2e, CO_2eq, or CO_2-equiv. To convert CO_2, CH_4, and N_2O emissions into CO_2-equivalents, multiply CH_4 emissions by 21 and N_2O emissions by 310, then add both to the corresponding CO_2 emissions.

CO_2-equivalents are also sometimes reported as the weight of the carbon in the CO_2-equivalents, usually reported in metric tonnes of carbon equivalents (MTCEs). MTCEs are calculated by multiplying the weight (in tonnes, equal to 1000 kg) of CO_2-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 CO_2-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 CO_2-equivalents or MTCEs. This is acceptable provided it is made clear in the results.

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[2] Recent research summarized in IPCC 2001 suggests that the GWP for CH_4 should be higher (23) and that for N_2O 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 CH_4 and 310 for N_2O).

4.3.2 *Heat Content of Fuels – GCV vs. NCV*

Some countries measure fuel according to its gross calorific value (GCV) or higher heating value (HHV), while other countries use net calorific value (NCV) or lower heating value (LHV). The distinction between GCV and NCV arises from the different physical states (liquid or gaseous) water may be in following combustion. The GCV includes the latent energy of condensation of water following combustion. The NCV is computed for product water in the gaseous state (i.e., not condensed). The latent energy of vaporization of water is deducted from the GCV. 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 NCV of a fuel at any moisture content can be determined as (Kitana and Hall 1989, p. 883):

$$NCV = (1 - M_{wet})[GCV_{solids} - \lambda(M_{dry} + 9H)] \qquad \textit{(Eq. 1)}$$

where: *NCV = net calorific value at any moisture content*
GCV_{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 NCV 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 GCV of the dry fuel (GCV_{solids}):

$$NCV_{solids} = GCV_{solids} - 9\lambda H \qquad \textit{(Eq. 2)}$$

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

A commonly accepted approximation is that NCV is 95% of GCV for coal and oil and 90% of GCV for natural gas (IPCC 1997c). IPCC does not provide a relationship between NCV and GCV 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 GCV 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 NCV_{solids} value for wood is 20 MJ/kg (IPCC 1997c). Therefore:

$$\begin{aligned} NCV_{solids} &= 20\,\text{MJ/kg dry wood} = GCV_{solids} - 9\times(2.31\,\text{MJ/kg water})\times(0.06) \\ \therefore GCV_{solids} &= 20\,\text{MJ/kg dry wood} + 9\times(2.31\,\text{MJ/kg water})\times(0.06) \\ &= 21.25\,\text{MJ/kg dry wood} \end{aligned} \qquad \textit{(Eq. 3)}$$

An approximate relationship between NCV_{solids} and GCV_{solids} can be developed using this result:

$$\therefore \frac{NCV_{solids}}{GCV_{solids}} = \frac{20}{21.25} = 0.94 \cong 0.95 \qquad \textit{(Eq. 4)}$$

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

In this report, NCV (LHV) is used. In some cases, the emission factors have been converted from GCV (HHV) 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 NCV (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 2004a). 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 WRI/WBCSD 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 the consistency with financial accounting (WRI 2004a).

After the organizational boundaries of the company have been determined, operational boundaries then categorize direct and indirect emissions, using the approach chosen under organizational boundaries (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 mill 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
- mills where multiple parties share ownership of the facility

6.0 IDENTIFYING PULP AND PAPER 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 pulp and paper mill operations with the potential to emit greenhouse gases include:

- power boilers, gas turbines, and other combustion devices producing steam and/or power for the mill
- recovery furnaces and other devices burning spent pulping liquors
- incinerators
- lime kilns and calciners
- gas- or other fossil fuel-fired dryers (e.g., infrared dryers)
- 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 mill wastes (usually included in the boundaries of the inventory only if on-site or owned by the company)
- on-site vehicles and machinery
- harvesting equipment used to supply the mill (usually included in the boundaries of the inventory only if owned by the company)
- trucks used to transport raw materials, products, or wastes for the mill (usually included in the boundaries of the inventory only if owned by the company)

Examples of pulp and paper mill operations that may be associated with the *indirect* emission of greenhouse gases because they sometimes consume purchased power or steam include:

- preparing virgin fiber (debarking, chipping, and other woodyard operations, usually included only if owned by the company)
- preparing recovered fiber, including deinking
- mechanical pulping
- chemical pulping
- semi-chemical pulping

- other chemical pulping processes
- chemical recovery operations
- pulp screening, thickening, and washing
- virgin fiber bleaching and recovered fiber bleaching and brightening
- on-site production of chlorine dioxide and other bleaching chemicals
- paper and paperboard production, including stock cleaning and refining
- coating, including extrusion coating
- trimming, roll wrapping, sheet cutting, etc.
- normal office and building operations for mill employees
- equipment for incoming process water treatment and waste treatment
- non-fossil fuel-fired emission control devices (e.g., ESPs, biofilters)

There are several types of ancillary operations that may be associated with mill 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:

- chemical plants located at the mill site
- merchant power plants located adjacent to the mill whose primary business is selling electricity
- converting operations that are not conducted on-site at most mills

7.0 MATERIALITY AND INSIGNIFICANT EMISSIONS

Greenhouse gas protocols generally allow companies to ignore emissions that are so small that they do not significantly impact the estimation 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 2004a). 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 2004a).

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 may 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 was determined to be immaterial, the cummulative 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 CO_2 emissions from fossil fuel combustion. In most cases, CH_4 and N_2O contribute relatively small quantities to a mill's GHG emissions, even on a CO_2-equivalents basis. In addition, sources other than fossil fuel combustion will be comparatively small. Other sections of this report contain example calculations that 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 CO_2 from biomass combustion because under the GHG Protocol this CO_2 is not included in GHG totals but is reported separately, as in national GHG inventories.

In the results of the inventory, companies should identify those situations where emissions have been estimated to be too small to materially impact 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 mill's or company's direct emissions.

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

	Units	Fossil-CO_2	CH_4 (CO_2-equiv.)*	N_2O (CO_2-equiv.)*	Tables in Report Containing Default Values
Natural gas used in boilers	kg CO_2-equiv./TJ	56,100 – 57,000	13 – 357	31 – 620	2, 4, 5
Residual oil used in boilers	kg CO_2-equiv./TJ	76,200 – 78,000	13 – 63	93 – 1550	2, 4, 5
Coal used in boilers	kg CO_2-equiv./TJ	92,900 – 126,000	15 – 294	155 – 29,800$^{\Theta}$	2, 4, 5
Bark and wood waste fuel	kg CO_2-equiv./TJ	0	<21 – 860	<310 – 8060	8
Black liquor	kg CO_2-equiv./TJ	0	42 – 630	1550	8
Lime kilns	kg CO_2-equiv./TJ	depends on fuel	21 – 57	0^{ψ}	2, 6
Lime calciners	kg CO_2-equiv./TJ	depends on fuel	21 – 57	1550^{λ}	2, 6
Pulp mill make-up $CaCO_3$	kg CO_2/t $CaCO_3$	440	0	0	7
Pulp mill make-up Na_2CO_3	kg CO_2/t Na_2CO_3	415	0	0	7
Diesel fuel used in vehicles	kg CO_2-equiv./TJ	74,000 – 75,300	82 – 231	620 – 9770	2, 9
Gasoline in non-road mobile sources and machinery – 4-stroke engines	kg CO_2-equiv./TJ	69,300 – 75,300	84 – 30,900	93 – 2580	2, 9
Gasoline in non-road mobile sources and machinery – 2-stroke engines	kg CO_2-equiv./TJ	69,300 – 75,300	9,860 – 162,000	124 – 861	2, 9
Anaerobic wastewater treatment	kg CO_2-equiv./kg COD treated	0	5.25^{η}	0	Eqs. 6, 7
Mill solid waste landfills	kg CO_2-equiv./dry ton solid waste	0	$3{,}500^{\infty}$	0	Eqs. 1,3,5; Table 10

[*] CO_2-equivalents are calculated from IPCC Global Warming Potentials ($CH_4 = 21$, $N_2O = 310$).

$^{\Theta}$ Reported N_2O emission factors greater than 1500 kg CO_2-equiv../TJ are generally limited to fluidized bed boilers.

$^{\psi}$ IPCC information suggests N_2O is not likely to be formed in lime kilns in significant amounts.

$^{\lambda}$ Amounts of N_2O, if any, formed in calciners are not known, so the largest factor for fuels normally used in kilns is shown here.

$^{\eta}$ Assumes no capture of gas from the treatment plant.

$^{\infty}$ 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.

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 pulp and paper mills. Emissions of CO_2 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 mill
- 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 content and 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. CO_2 emission factors and information on fossil fuel carbon content and unoxidized carbon are available from most national authorities and a variety of existing protocols. The IPCC generic (Tier 1) emission factors are shown in Table 2.

To correct CO_2 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 CO_2 Emission Factors for Fossil Fuels (after IPCC 1997b)

Fossil Fuel	Uncorrected Emission Factor kg CO_2/TJ*	Corrected Emission Factor kg CO_2/TJ
Crude oil	73,300	72,600
Gasoline	69,300	68,600
Kerosene	71,900	71,200
Diesel oil	74,100	73,400
Residual fuel oil	77,400	76,600
LPG	63,100	62,500
Petroleum coke	100,800	99,800
Anthracite coal	98,300	96,300
Bituminous coal	94,600	92,700
Sub-bituminous coal	96,100	94,200
Lignite	101,200	99,200
Peat	106,000	104,900
Natural gas	56,100	55,900

* 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.

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 (2004)*	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 (2004) do not specify correction factors for unoxidized carbon, however all emission factors presented in VCR (2004) are drawn from Environment Canada 2004

In many cases, total CO_2 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 mill is burning natural gas in several boilers and infrared dryers, the CO_2 emissions from natural gas burning can be estimated from the total gas used. In fact, some mills may lack the fuel metering devices that would be required to estimate emissions from each combustion unit separately.

If a mill exports fossil fuel-derived CO_2, for instance to an adjacent precipitated calcium carbonate (PCC) plant, these exports should not be included in the emissions estimates because this CO_2 is not emitted by the mill. A separate line is included in the example results table (Table 13) to report exports of fossil fuel-derived CO_2.

NCASI has access to data which indicate that the combustion efficiencies of some natural gas-fired combustion devices (e.g., some types of gas-fired dryers) and emission control devices such as Regenerative Catalytic Oxidizers (RCOs) and Regenerative Thermal Oxidizers (RTOs) can sometimes be relatively low compared to power boilers, allowing a portion of the fuel to exit the combustion device 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 CO_2 emissions 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 CO_2 emissions to account for the unburned fuel. An example of this type of calculation can be found in the report *Calculation tools for estimating greenhouse gas emissions from wood products manufacturing facilities* (NCASI 2004).

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-CO_2. 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-CO_2 emission factor of 557 kg CO_2/wet tonne MSW burned.

8.2 Methane and Nitrous Oxide

Methane and nitrous oxide emissions from fossil fuel combustion are usually very small compared to CO_2 emissions. Indeed, some inventory protocols do not address CH_4 and N_2O from fossil fuel combustion. Because some inventories include CH_4 and N_2O, 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 CH_4 and N_2O from fossil fuel combustion are insignificant compared to CO_2 emissions. In other cases, a single emission factor might be available that includes fossil-CO_2, CH_4, and N_2O

emissions expressed as CO_2-equivalents. In this case, the company may not need to report the three gases separately.

Estimating CH_4 and N_2O 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 such as boilers, recommended emission factors follow this order of preference:

- data on the specific fuels and combustion devices being used at the mill
- 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 CH_4 and N_2O from fossil fuel-fired boilers and other combustion devices. 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 mill burning 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 4. IPCC's Tier 2 emission factors, shown in Table 5 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.

Table 4. IPCC Tier 1 CH_4 and N_2O Emission Factors for Stationary Combustion (from IPCC 1997c)

	CH_4 Emission Factors kg/TJ	N_2O Emission Factors kg/TJ
Coal	10	1.4
Natural gas	5	0.1
Oil	2	0.6
Wood/wood residuals	30	4

Table 5. IPCC Tier 2 Uncontrolled CH_4 and N_2O Emission Factors for Industrial Boilers (IPCC 1997c)

Fuel	Technology	Configuration	kg CH_4/TJ	kg N_2O/TJ
Bituminous coal	Overfeed stoker boilers		1.0	1.6
Sub-bituminous coal	Overfeed stoker boilers		1.0	1.6
Bituminous coal	Underfeed stoker boilers		14	1.6
Sub-bituminous coal	Underfeed stoker boilers		14	1.6
Bituminous coal	Pulverized	Dry bottom, wall fired	0.7	1.6
Bituminous coal	Pulverized	Dry bottom, tang. fired	0.7	0.5
Bituminous coal	Pulverized	Wet bottom	0.9	1.6
Bituminous coal	Spreader stoker		1.0	1.6
Bituminous coal	Fluidized bed	Circulating or bubbling	1.0	96
Sub-bituminous coal	Fluidized bed	Circulating or bubbling	1.0	96
Anthracite			10*	1.4*
Residual oil			3.0	0.3
Distillate oil			0.2	0.4
Natural gas	Boilers		1.4	0.1*
Natural gas	Turbines		0.6	0.1*
Natural gas	Int. comb. engine	2-cycle lean burn	17	0.1*
Natural gas	Int. comb. engine	4-cycle lean burn	13	0.1*
Natural gas	Int. comb. engine	4-cycle rich burn	2.9	0.1*

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

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 N_2O 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 4 and 5 unless other factors that are more suited to individual mill 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 9.

Fossil fuels can be used in a number of different combustion units common in the forest products industry. Some specific recommendations for estimating CH_4 and N_2O emissions from certain types of units found exclusively or primarily in the forest products industry are shown below.

Recovery furnaces – In most cases, only small amounts of fossil fuel are burned in recovery furnaces. The CO_2 releases from the fossil fuel can be estimated using the methods described in Section 8.1. Where large amounts of fossil fuels are being burned (i.e., they represent a major source of fuel on an ongoing basis), best professional judgment will be required to select the most appropriate emission factors for CH_4 and N_2O. In the vast majority of cases, however, the small amounts of fossil fuel used in the recovery furnace can be included in the firing rate used to estimate CH_4 and N_2O from liquor burning. The CH_4 and N_2O emissions factors for recovery furnaces are included in the Section 11.2.

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 CH_4 and N_2O emissions from combination fuel-fired boilers be estimated from the total heat input to the boiler and CH_4 and N_2O emission factors for biomass. These emission factors are summarized in Section 11.2.

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 CH_4 and N_2O 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 fuels' emission factors, plus the consumption rate of biomass fuel multiplied by the biomass fuels' emission factors.

Kraft mill lime kilns and calciners – The emissions from lime kilns and calciners are unique enough to warrant separate discussion (presented in Section 9 and Annex A).

Gas-fired infrared dryers, incinerators, and other miscellaneous pulp and paper sources – CO_2 releases from the fossil fuel used in these units can be estimated using the methods described in Section 8.1. Lacking site-specific information, companies will either have to assume that the methane and nitrous oxide emissions from these sources are negligible (based on the amounts of fuel burned) or use the Tier 1 emission factors or those developed for similar fuels burned in other operations. The data in Table 1 suggest that it should be relatively simple for many companies to document that these sources of CH_4 and N_2O are so small that they can be ignored in the inventory. The fossil CO_2 from these sources can be estimated directly from the carbon content of the fuel or CO_2 emission factors, using the same methods as for other stationary combustion units.

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

Based on the information in Section 8.2, the following general guidance is provided for estimating methane and nitrous oxide emissions.

- 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) 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 Calculation: CO_2, CH_4, and N_2O emissions from natural gas use at a small mill.

A mill uses natural gas in a small boiler and in several infrared dryers. The mill's records indicate that over a year's time, it used 17 million standard cubic meters of natural gas. The mill decides to estimate the emissions from overall natural gas consumption instead of attempting to separate boiler emissions from the infrared dryer emissions. The mill does not know the carbon content of its gas supply, but the IPCC emission factor is 55.9 metric tons CO_2/TJ (after correcting for 0.5% unoxidized carbon). The mill uses the CH_4 and N_2O emission factors from Table 4 (5 kg CH_4/TJ and 0.1 kg N_2O/TJ). The mill estimates the heating value of the natural gas to be 52 TJ/kiloton and the density to be 0.673 kg/standard cubic meter. The annual emissions are estimated as follows.

CO_2 emissions:

- $(17 \times 10^6$ m^3 gas/y) x (0.673 kg/m^3) = 11.4×10^6 kg gas/y = 11.4 ktonne gas/y
- (11.4 ktonne gas/y) x (52 TJ/kiloton) = 595 TJ/y
- (595 TJ/y) x (55.9 t CO_2/TJ) = 33,300 tonne CO_2/y

CH_4 emissions

- (595 TJ NCV/y) x (5 kg CH_4/TJ NCV) = 2975 kg CH_4/y = 2.975 tonne CH_4/y

Using the IPCC GWP of 21, this is equal to 62.5 tonne CO_2-eq./y

N_2O emissions

- (595 TJ NCV/y) x (0.1 kg N_2O/TJ NCV) = 59.5 kg N_2O/y = 0.06 tonne N_2O/y

Using the IPCC GWP of 310, this is equal to 18 tonne CO_2-eq./y

Total GHG emissions = 33,300 + 62.5 + 18 = 33,400 tonne CO_2-equivalents/y

On a CO_2-equivalents basis, CH_4 and N_2O emissions are approximately 0.25% of CO_2 emissions. These emissions would be very small even if the emission factors were several times larger. Because of this, the company might decide against including CH_4 and N_2O estimates in the results, and instead indicate in the results that the estimates demonstrate that the emissions are not material to the results of the inventory because they are less than 0.25% of CO_2 emissions.

Example Calculation: CO_2, CH_4, and N_2O 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 pounds/hr). Over a year's time, the mill's records indicate that the boiler consumed 336,000 Mg (370,000 short tons) of coal having a higher heating value, on average, of 13,000 Btu HHV/lb.

Case 1: CO_2 emissions based on carbon content of fuel

The mill has information on the carbon content of the coal being burned in the boiler (80.1% carbon, by weight). The mill decides that the default IPCC correction for unburned carbon in coal-fired boilers (2% unburned carbon) is appropriate. The mill decides to use the Tier 2 IPCC emission factors for CH_4 and N_2O from Table 5. The IPCC Tier 2 emission factors for dry bottom, wall fired boilers burning pulverized bituminous coal are 0.7 kg CH_4/TJ NCV and 1.6 kg N_2O/TJ NCV. The mill applies the usual assumption that the NCV (or LHV) for coal is 5% lower than the GCV (or HHV). The annual emissions of CO_2, CH_4, and N_2O are estimated as follows.

CO_2 emissions:

- (336,000 Mg/y coal) x (0.801 Mg carbon / Mg coal) x (0.98 Mg carbon burned) x (44 Mg CO_2 / 12 Mg carbon) = 967,000 Mg CO_2/yr or 967 x 10^3 t CO_2/yr

CH_4 emissions:

- 370,000 short tons coal/y = 740 x 10^6 pounds/y
- (740 x 10^6 pounds/y) x (13,000 Btu HHV/pound) = 9.62 x 10^{12} Btu HHV/y
- for coal, LHV is 0.95 times HHV (see Section 4.4.2)
- (9.62 x 10^{12} Btu HHV/y) x (0.95 to correct to LHV) = 9.14 x 10^{12} Btu LHV/y
- (9.14 x 10^{12} Btu LHV/y) x (1055 J/Btu) = 9.64 x 10^{15} J NCV/y = 9.64 x 10^3 TJ NCV/y
- CH_4 emissions = (9.64 x 10^3 TJ NCV/y) x (0.7 kg CH_4/TJ NCV) = 6.75 x 10^3 kg CH_4/y or 6.75 t CH_4/y

Using the IPCC GWP of 21 for CH_4, this equates to 142 t CO_2-eq./y

N_2O emissions:

- N_2O emissions = (9.64 x 10^3 TJ NCV/y) x (1.6 kg N_2O/TJ NCV) = 15.4 t N_2O/yr

Using the IPCC GWP of 310 for N_2O, is to 4780 t CO_2-eq./y

Total GHG emissions = 967,000 + 142 + 4,780 = 972,000 t CO_2-equivalents/y

Compared to its CO_2 emissions, emissions of CH_4 and N_2O from this boiler are very small.
CO_2 emissions = 967,000 t CO_2/y
CH_4 emissions = 142 t CO_2-eq./y or 0.015% of CO_2 emissions
N_2O emissions = 4,780 t CO_2-eq./y or about 0.5% of CO_2 emissions

Example Calculation: CO_2, CH_4, and N_2O 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 pounds/hr). Over a year's time, the mill's records indicate that the boiler consumed 336,000 Mg (370,000 short tons) of coal having a higher heating value, on average, of 13,000 Btu HHV/lb.

Case 2: CO_2 emissions based on emission factors

In this case the mill does not have information on the carbon content of the coal being burned in the boiler. The IPCC default Tier 1 emission factor for CO_2 is 94.6 t CO_2/TJ NCV. The mill decides that the default IPCC correction for unburned carbon in coal-fired boilers (2% unburned carbon) is appropriate.

CO_2 emissions:

- 370,000 short tons coal/y = 740 x 10^6 pounds/y
- (740 x 10^6 pounds/y) x (13,000 Btu HHV/pound) = 9.62 x 10^{12} Btu HHV/y
- for coal, LHV is 0.95 times HHV (see Section 4.4.2)
- (9.62 x 10^{12} Btu HHV/y) x (0.95 to correct to LHV) = 9.14 x 10^{12} Btu LHV/y
- (9.14 x 10^{12} Btu LHV/y) x (1055 J/Btu) = 9.64 x 10^{15} J NCV/y = 9.64 x 10^3 TJ NCV/y
- uncorrected CO_2 emissions = (9.64 x 10^3 TJ NCV/y) x (94.6 t CO_2 /TJ NCV) = 912 x 10^3 t CO_2/y
- CO_2 emissions corrected for 2% unburned carbon = 894 x 10^3 t CO_2/y

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

CO_2 emissions = 894,000 t CO_2/y
CH_4 emissions = 142 t CO_2-eq./y or 0.016% of CO_2 emissions
N_2O emissions = 4,780 t CO_2-eq./y or about 0.5% of CO_2 emissions

As in the previous example, this comparison suggests that it may be relatively simple for many mills to document that emissions of CH_4 and N_2O from fossil fuel-fired boilers are not material to the results of their inventory.

9.0 EMISSIONS FROM KRAFT MILL LIME KILNS AND CALCINERS

Fossil-CO_2 emissions from kraft mill lime kilns and calciners are estimated using the same approach as used for other stationary fossil fuel combustion devices–by determining how much fossil fuel is used in the kiln and estimating emissions from information on the fuel carbon content or emission factors. These CO_2 emissions are reported together with other fossil fuel-related CO_2 emissions.

Although CO_2 is also liberated from the $CaCO_3$ burned in the kiln or calciner, the carbon released from $CaCO_3$ is biomass carbon that originates in wood and should not be included in GHG emissions totals. Companies wanting to prepare inventory reports that are consistent with the requirements of the WRI/WBCSD GHG Protocol should report these biomass-related emissions, but keep them separate from direct emissions from fossil fuel combustion. Annex E provides an example format that can be used for reporting this additional information. The movement of carbon in kraft pulp mills and the reasons for differentiating biomass- from fossil-CO_2 emissions from lime kilns are explored in detail in Annex A to this report and in a paper by Miner and Upton (2002).

There are very few data on CH_4 and N_2O emissions from kraft mill lime kilns and calciners. This review uncovered data from only three lime kilns sampled in the early 1980s (NCASI 1981). These data suggest an emission factor of 2.7 kg CH_4/TJ. For commercial lime kilns, IPCC suggests emission factors of 1.0 and 1.1 kg CH_4/TJ for oil-fired and gas-fired lime kilns, respectively. The IPCC factors are for commercial lime kilns, however, and may not be appropriate for kraft mill lime kilns. Table 1 illustrates that for fossil fuel-fired kilns or calciners, CH_4 emissions will be very small compared to the CO_2 from fossil fuel.

No data were found for N_2O from lime kilns or calciners, but the temperatures in rotary lime kilns appear to be too high to allow significant generation of N_2O (see Annex A for more information). It is reasonable, therefore, to assume that N_2O emissions from rotary lime kilns are negligible. The temperatures in calciners appear to be more amenable to N_2O generation (see Annex A). Given the range of N_2O emission factors for oil and gas, however, it seems likely that N_2O emissions will be small relative to fossil-CO_2 emissions from fossil fuel-fired calciners.

The emission factors suggested for kraft mill lime kilns and calciners are summarized in Table 6.

At a number of mills around the world, stack gas from lime kilns or calciners is piped to adjacent precipitated calcium carbonate (PCC) plants for use as a raw material (PCC is sometimes used as an inorganic filler or coating material in paper and paperboard products). A separate line is included in the example inventory result tables to show the amounts of fossil fuel CO_2 being exported to PCC plants. These exports of fossil fuel-derived CO_2 should not be included in the estimates of GHG emissions because they are not emitted by the mill. If the mill also wants to show the amounts of biomass-derived CO_2 that are exported with lime kiln stack gas, it can include this as additional information (see Annex E).

A mill may sometimes export CO_2 to the PCC plant when the PCC plant is not operating. These calculation tools do not require that the exports be corrected to account for these periods because the mill no longer owns the exported CO_2 and cannot control whether the PCC plant uses it. Presumably, if the PCC plant were to conduct an inventory, any unused fossil-CO_2 received from the mill would be shown as a direct emission in its inventory. Exports of fossil fuel CO_2 to PCC plants are shown in the results table (Table 13). This table is also used to show any imports of CO_2 to the mill; for use in neutralization, for instance.

Table 6. Emission Factors for Kraft Mill Lime Kilns and Calciners

	Emissions, kg/TJ					
Fuel	Kraft mill lime kilns			Kraft mill calciners		
	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
Residual oil	76,600*	2.7 [θ]	0 [χ]	76,600*	2.7 [θ]	0.3 [ϕ]
Distillate oil	73,400*	2.7 [θ]	0 [χ]	73,400*	2.7 [θ]	0.4 [ϕ]
Natural gas	55,900*	2.7 [θ]	0 [χ]	55,900*	2.7 [θ]	0.1 [ϕ]
Biogas	0	2.7 [θ]	0 [χ]	0	2.7 [θ]	0.1[δ]

[*] From Table 2, corrected for unburned carbon

[θ] From NCASI 1981

[χ] Based on IPCC description of temperatures giving rise to N_2O emissions

[ϕ] From Table 5

[δ] Assumed appropriate to use the emission factor for natural gas, as the composition and combustion conditions for biogas are more similar to natural gas than to other fuels

These draft calculation tools do not address the ultimate fate of exported CO_2 or the ownership of any CO_2 that is ultimately emitted from the PCC plant, as both issues are outside the boundary of pulp and paper operations. Nor does it address the question of how much of this carbon is sequestered as a result of being converted to PCC. Ultimately, however, most of the carbon in PCC is sequestered in landfilled paper, landfilled residuals from deinking mills, or ash from burning used paper.

Example Calculation: GHG emissions from a natural gas-fired lime kiln.

A 1000 ton/day kraft mill has a single gas-fired lime kiln. The mill's records indicate that it used 28.6 x 10^6 pounds of gas last year with a typical heat content of 21,000 Btu HHV/lb and a density of 0.77 kg/m^3. The IPCC CO_2 emission factor for natural gas from boilers can be used for lime kilns since the CO_2 emissions are a function only of gas composition. The IPCC CO_2 emission factor for natural gas is 55.9 t CO_2/TJ (after correcting for 0.5% unoxidized carbon). For CH_4, the mill decides to use the only available emission factor for kraft mill lime kilns (2.7 kg CH_4/TJ) and assumes that N_2O emissions are negligible based on the IPCC discussion of temperatures needed to generate N_2O. The kiln's GHG emissions are estimated as follows.

CO_2 emissions:

- 28.6 x 10^6 pounds gas/y x 21,000 Btu HHV/lb = 601 x 10^9 Btu HHV/y
- for natural gas, LHV is 0.9 times HHV (see Section 4.4.2)
- 601 x 10^9 Btu HHV/y x 0.9 (to convert to LHV) = 541 x 10^9 Btu LHV/y
- 541 x 10^9 Btu/y x (1.055 x 10^{-6} GJ/Btu) = 570,000 GJ/y = 570 TJ/y
- 570 TJ/y x 55.9 t CO_2/TJ = 31,900 t CO_2/y

CH_4 emissions:

- 570 TJ/y x 2.7 kg CH_4/TJ = 1540 kg CH_4/yr

Using the IPCC CO_2 equivalency factor of 21, this equals 32 t CO_2-equivalents. This is a very small number compared to the CO_2 emissions (31,900 t). In addition, the estimate is based on a small and old data set. Consequently, in the inventory results the mill might decide to report that the CH_4 emissions from this source are non-material to the inventory.

N_2O emissions:

- As discussed above and in more detail in Annex A, IPCC's analysis of the temperatures needed to form N_2O in combustion processes suggests that it is unlikely that significant amounts of N_2O would be formed in lime kilns. The mill would probably decide to note this in the inventory results.

Total GHG emissions = 31,900 + 32 + 0 = 31,900 CO_2-equivalents/y

10.0 CARBON DIOXIDE EMISSIONS FROM MAKE-UP CHEMICALS

10.1 Emissions from Make-up Carbonates Used in the Pulp Mill

Although losses of sodium and calcium from the recovery system are usually made up using non-carbonate chemicals, small amounts of $CaCO_3$ and Na_2CO_3 are sometimes used. The carbon contained in these chemicals is usually of fossil origin, although in some cases (e.g., Na_2CO_3 purchased from soda-based semi-chem mills) it can be derived from biomass. In these calculation tools, it is assumed that the carbon in these make-up chemicals escapes as CO_2 from the lime kiln or recovery furnace. These emissions are estimated by assuming that all of the carbon in $CaCO_3$ and Na_2CO_3 used in the recovery and causticizing areas is released to the atmosphere. The amounts are usually small enough that under normal circumstances it is reasonable to use either mill purchasing records or industry norms to develop the estimates. If the carbon in make-up chemicals is biomass in origin (an uncommon situation), the CO_2 released from it is not considered a GHG emission, and in these cases this carbon does not need to be included in GHG totals, although the GHG Protocol requires that it be included in the report as additional information. See Annex E for more information.

The conversion factors for estimating fossil-CO_2 releases from the use of carbonate-based make-up chemicals in the pulp mill are shown in Table 7.

Table 7. Emissions from Calcium Carbonate and Sodium Carbonate Make-up in the Pulp Mill*

	Emissions
Pulp mill make-up $CaCO_3$	440 kg CO_2/ t $CaCO_3$
Pulp mill make-up Na_2CO_3	415 kg CO_2/ t Na_2CO_3

* If the carbonate is derived from biomass, GHG emissions are zero

It is important to note that calcium make-up is required because of losses from the causticizing area, most of which are in the form of calcium carbonate. This lost material is usually landfilled, thereby sequestering the carbon contained in the calcium carbonate. Because the default method in these calculation tools does not consider this loss of carbon from the system, the estimated CO_2 emissions from make-up calcium carbonate will be higher than actual emissions. Where these emissions are significant, companies may want to perform the more detailed analyses required to correct the emissions estimates to account for the carbon that leaves the causticizing area in calcium carbonate.

Example Calculation: Kraft mill using $CaCO_3$ for make-up at the lime kiln.

A 2000 tpd kraft mill determined from mill records that it uses about 7000 t (7700 short tons) $CaCO_3$ a year as make-up in the causticizing area (make-up rate of about 2% for this mill). This $CaCO_3$ is from a source where carbonate would be expected to be fossil (not biomass) in origin. The emissions are estimated as follows.

- (7000 t $CaCO_3$/y) x 440 kg CO_2/t $CaCO_3$ = 3,080,000 kg CO_2/y = 3080 t CO_2/y

10.2 Emissions from Limestone or Dolomite Used in Flue Gas Desulfurization (FGD) Systems

Limestone ($CaCO_3$) and dolomite ($CaCO_3MgCO_3$)[1] are basic raw materials used by a wide variety of industries, including as a sorbent in flue gas desulfurization (FGD) systems and fluidized bed boilers at electric utility and industrial plants. For example, wet limestone “scrubbers” use limestone slurries–mixtures of water and very finely crushed limestone–to prevent sulfur dioxide from passing through smokestacks. A rapid chemical reaction between sulfur dioxide gas and crushed limestone combines the gas with calcium and oxygen, forming a removable solid waste. During this reaction the limestone is heated and CO_2 is generated as a by-product. Some coal-fired boilers at pulp and paper mills incorporate such FGD systems.

Carbon dioxide emissions associated with the use of limestone as a sorbent material can be calculated by multiplying the quantity of limestone or dolomite consumed by its average carbon content, approximately 12% by mass for limestone and 13% for dolomite (based on stoichiometry). This approach assumes that all carbon in the mineral is oxidized and released and that impurities constitute a minor fraction of the material. Converting these percentages to a mass ratio of CO_2 to limestone using a molecular weight ratio produces emission factors of 0.440 tonne CO_2/tonne limestone consumed and 0.447 tonne CO_2/tonne dolomite consumed. The quantity of limestone consumed can be estimated based on purchase records or metered data (e.g., scales).

The limestone used for industrial purposes is often a combination of pure limestone, dolomite, and minor impurities (e.g., magnesia, silica, and sulfur). Uncertainties in estimates of CO_2 emissions from limestone used as sorbents are due, in part, to variations in the chemical composition of limestone.

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[1] Limestone and dolomite are collectively referred to as limestone by the industry, and intermediate varieties are seldom distinguished.

11.0 EMISSIONS FROM STATIONARY COMBUSTION OF BIOMASS FUELS

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

Many pulp and paper mills generate more than half their energy needs from biomass fuels recovered from the industry's waste and process streams. The CO_2 generated when biomass fuels are burned is not included in GHG emission totals. The GHG Protocol, however, requires that biomass-derived CO_2 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 CO_2 emissions from biomass burning, but methods are provided for estimating biomass-derived CO_2 so that it can be reported where needed (see Annex E).

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 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).

Therefore, in keeping with well-established practices, the greenhouse gas inventory results generated using these calculation tools do not include CO_2 emissions from biomass burning. The WRI/WBCSD GHG Protocol and some national reporting schemes, however, require that these emissions be estimated and reported, but kept separate from direct GHG emissions. These calculation tools provide a venue for this, with biomass combustion CO_2 emissions reported separately. Annex E contains information that will assist companies that want to comply with these requirements.

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 pulp and paper mills)
- bagasse
- bio-alcohol
- black liquor
- landfill gas
- sludge gas

CO_2 emissions from peat burning are usually considered to be GHGs and are included in the emissions from fossil fuel burning (Table 2).

Non-condensable gases (NCGs) consist of reduced sulfur compounds and other organic compounds that are formed during the kraft pulping process. These gases are often collected and burned in boilers, lime kilns, or incinerators as a pollution abatement procedure. Because the carbon in NCGs originated in wood, the CO_2 generated during combustion of NCGs is of biomass origin and is, therefore, not included in a tabulation of direct GHG emissions. The quantities of NCGs combusted at kraft mills are very low relative to quantities of spent pulping liquors and other wood residuals fuels. There are no data on methane or nitrous oxide generation from combustion of NCGs.

11.2 Methane and Nitrous Oxide Emissions from Burning Biomass Fuels

Although CO_2 from biomass burning is almost universally excluded from GHG inventories, CH_4 and N_2O from biomass burning are sometimes included because these gases do not participate in the atmospheric CO_2 sequestration-recycling process explained in Section 11.1. Therefore, calculation tools are provided to assist in estimating these emissions.

If a company has reliable site-specific data allowing it to estimate CH_4 and N_2O 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 CH_4 and N_2O emissions from biomass combustion.

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. Even the updated EPA factors, however, are based on very few data. Table 8 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 8. 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. As discussed in Section 11.1, there are no data on methane or nitrous oxide emissions from combustion of NCGs generated during the kraft pulping process.

Where an emission factor shown in Table 8 was developed for circumstances that match conditions at a mill, 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 2004). For wood-fired combustion equipment other than boilers, it may be most appropriate to use the IPCC Tier 1 emission factors shown in Table 4. 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 8. Emission Factors for CH_4 and N_2O from Biomass Combustion

Emission Factor Description	kg CH_4/TJ	kg N_2O/TJ	Reference
Wood waste-fired boilers			
Wood, wood waste, and other biomass and wastes	30	4	Tier 1 – IPCC 1997c
Uncontrolled emissions from wood-fired stoker boilers	15	-	Tier 2 – IPCC 1997c
Average for wood residue combustion	9.5*	5.9*	USEPA 2001
Average for circulating fluidized bed boilers burning peat or bark	1	8.8	Fortum 2001
Average for bubbling fluidized bed boilers burning peat or bark	2**	<2	Fortum 2001
Pre-1980 wood residue-fired stoker boilers sampled ahead of control devices	8.2*	-	NCASI 1980
Pre-1980 wood residue-fired stoker boilers sampled after wet scrubbers	2.7*	-	NCASI 1985
Wood fired boiler	41$^{\lambda}$	3.1$^{\lambda}$	JPA 2002
Wood as fuel	24 $^{\lambda}$	3.4 $^{\lambda}$	AEA Tech. 2001
Wood waste	30	5	Swedish EPA 2004
Median emission factors for wood waste	***12***	***4***	
	1 - 40	1.4 – 75	EEA 2004
Recovery furnaces			
Recovery furnace	<1	<1	Fortum 2001
Recovery furnace – black liquor	2.5 $^{\Omega}$	-	JPA 2002
Black Liquor	30	5	Swedish EPA 2004
Median emission factors for black liquor	***2.5***	***2***	
	1 –17.7	1 – 21.4	EEA 2004

* Converted from GCV to NCV assuming a 5% difference

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

$^{\lambda}$ Based on heat content of 20 GJ/t dry solids

$^{\Omega}$ Based on liquor heat content of 13.3 GJ/t dry solids

11.2.1 *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 CH_4 and N_2O 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 CH_4 and N_2O 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.

Example Calculation: Mill with a bark boiler.

A mill has a 250,000 kg steam/hour (550,000 pound/hr) circulating fluidized bed (CFB) bark boiler. In a year, the boiler burns approximately 6.9 x 10^6 GJ of bark and 0.8 x 10^6 GJ of residual fuel oil. Because the boiler receives supplemental fossil fuel, it is necessary 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 mill decides to use the IPCC emission factor for residual oil (76.6 t CO_2/TJ, 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 8, are 1 kg

CH_4/TJ and 8.8 kg N_2O/TJ.

CO_2 emissions from fossil fuel:
- (0.8 x 10^6 GJ/y) = (0.8 x 10^3 TJ/y)
- (0.8 x 10^3 TJ/y) x (76.6 t CO_2/TJ) = 61,300 t CO_2/y

CH_4 emissions:
- total heat input = (6.9 x 10^6 GJ/y) + (0.8 x 10^6 GJ/y) = 7.7 x 10^6 GJ/y = 7.7 x 10^3 TJ/y

7.7 x 10^3 TJ/y x 1 kg CH_4/TJ = 7,700 kg CH_4/y = 7.7 t CH_4/y

Using the IPCC warming potential of 21, this equates to 162 t CO_2-eq./y.

N_2O emissions:
- total heat input = 7.7 x 10^3 TJ/y
- 7.7 x 10^3 TJ/y x 8.8 kg N_2O/TJ = 67,800 kg N_2O/y = 67.8 t N_2O/y

Using the IPCC warming potential of 310, this equates to 21,000 t CO_2-eq./y

Total CO_2 equivalents emitted = 61,300 + 162 + 21,000 = 82,500 t CO_2-equivalents/y

12.0 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 2004a). 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.

12.1 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. It is often difficult, however, to determine whether published emission factors for electrical power include all GHGs or only CO_2 emissions. The difference is usually unimportant because CO_2 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 CO_2-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 CO_2-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 2004a). 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 (e.g., to satisfy national reporting requirements), this should be noted in the results.

12.2 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 pulp and paper mills, 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 CHP system, the emissions associated with the imported power can be estimated using the method described in Section 12.6. Of course, if a mill 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.

Example calculation: Mill purchasing electrical power.

A mill in Alberta, Canada purchases 300 TJ of electrical power (83,300 MWh) in a year's time. The Canadian VCR Registration Guide shows an average emission factor for purchased power in Alberta of 0.991 kg CO_2 eq./kWh. The indirect emissions associated with the purchased power are estimated as follows.

- 83,300 MWh/y = 83.3 x 10^6 kWh/y
- (83.3 x 10^6 kWh/y) x (0.991 kg CO_2-eq./kWh) = 82.6 x 10^6 kg CO_2-eq./y
  = 82,600 t CO_2-eq./y

12.3 Electricity Exports

These calculation tools suggest a format for reporting results wherein a mill 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 CO_2/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 the 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 mill to produce the exported power. Because exported electricity from mills is usually generated in combined heat and power (CHP) systems, companies will often need to use the methods for CHP systems (Section 12.6) 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 CO_2/MWh or kg CO_2/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 mill 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 mills usually export power into base loads (i.e., mills 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.

12.4 Steam Imports

In many cases where steam is imported by a mill, it is produced by a nearby CHP system. In these cases, the indirect emissions reported by the mill can be estimated using the allocation method described in Section 12.6. In other cases, the contractual arrangement between the mill and the steam 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 mill. In these calculations, the heat delivered to the mill 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.

12.5 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 12.6 should be used to allocate emissions. In either case, the heat delivered by the mill 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., 1 GJ of hot water energy is assumed to be equivalent to 1 GJ of steam energy, thermal losses during generation of hot water from mill-generated steam are assumed to be negligible).

12.6 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 mill owns the CHP system and uses all of its output, allocation is not necessary because all of the emissions are direct emissions for the mill. In many cases, however, a mill may either receive CHP energy from an outside provider or export a portion of its own CHP output. For instance, if a mill is importing steam from a nearby power plant, it is necessary to estimate the indirect emissions associated with the imported steam. Likewise, if a mill is exporting power from a CHP system but using the steam internally, one must estimate how much of the mill'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 B). This method is recommended 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. Where a company uses an alternative method, the method should be explained in the results.

The efficiency method is one of three methods recommended by WRI/WBCSD (WRI 2004b,c). There are two versions of the method. 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 mills and, therefore, it is included in this report as a default method. 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 B.

Where a mill 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.

12.6.1 *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 is 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 5 and 6. This approach is referred to in this report as the simplified efficiency method. The simplified efficiency method is recommended for mills that lack, or choose not to use, detailed design and operating data from CHP systems.

$$E_H = \left\{ \frac{H}{H + P \times R_{eff}} \right\} \times E_T ; \quad R_{eff} = \frac{e_H}{e_P} \qquad \textit{(Eq. 5)}$$

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:

$$E_P = E_T - E_H \qquad \textit{(Eq. 6)}$$

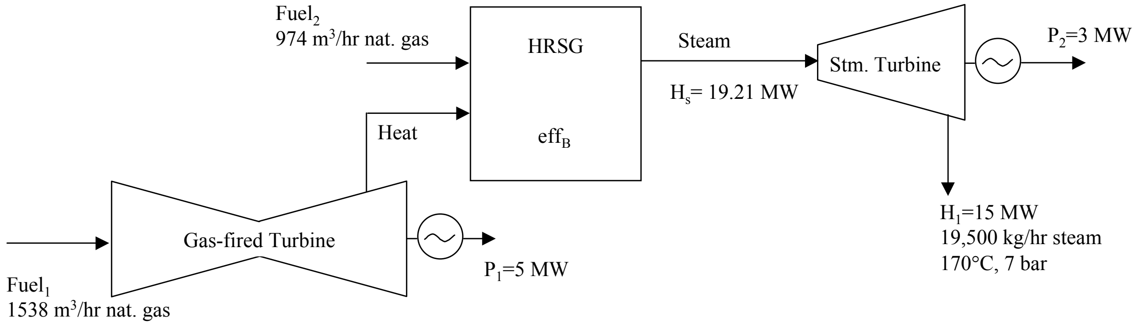
where: E_P *= emissions share attributable to electric power production*

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, 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 below makes use of these recommended default efficiency factors.

Example Calculation: Allocating CHP emissions to three output streams – Simplified efficiency method with WRI/WBCSD recommended default efficiency factors for the US.

A mill has the CHP system shown in the following 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 by WRI/WBCSD for the US; 0.35 for power generation and 0.8 for steam generation (WRI 2004b, c).



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:

Fuel$_1$:

CO_2 (1538 m^3/hr) x (0.039 GJ/m^3) x (55.9 kg CO_2/GJ) = 3353 kg CO_2/hr

CH_4 (1538 m^3/hr) x (0.039 GJ/m^3) x (0.0006 kg CH_4 /GJ) x (21 CO_2-eq. / CH_4) = 0.76 kg CO_2-eq./hr

N_2O (1538 m^3/hr) x (0.039 GJ/m^3) x (0.0001 kg N_2O /GJ) x (310 CO_2-eq. / N_2O) = 1.86 kg CO_2-eq/hr

Total Fuel$_1$ emissions = 3356 kg CO_2-eq./hr

Fuel$_2$:

CO_2 (974 m^3/hr) x (0.039 GJ/m^3) x (55.9 kg CO_2/GJ) = 2123 kg CO_2/hr

CH_4 (974 m^3/hr) x (0.039 GJ/m^3) x (0.0014 kg CH_4 /GJ) x (21 CO_2-eq. / CH_4) = 1.12 kg CO_2-eq./hr

N_2O (974 m^3/hr) x (0.039 GJ/m^3) x (0.0001 kg N_2O /GJ) x (310 CO_2-eq. / N_2O) = 1.18 kg CO_2-eq./hr

Total Fuel$_2$ emissions = 2126 kg CO_2-eq./hr

Total CHP system emissions = 3356 + 2126 = 5482 kg CO_2-eq./hr

Total system power output = $P_1 + P_2$ = 8 MW

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

$$E_H = \left\{ \frac{15MW}{15MW + (8MW \times 2.3)} \right\} \times 5482 kgCO_2 eq = 2462 kgCO_2 eq$$ = 20,681 t CO_2 eq/y at 350 d/y operation

$$E_P = 5482 kgCO_2 eq - 2462 kgCO_2 eq = 3020 kgCO_2 eq$$ = 25,368 t CO_2 eq/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*2462/5482 = 44.9%
- Percentage of CHP emissions to power output = 100*3020/5482 = 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 = (2462 kg CO_2-eq./hr)/15 MW = 164.1 kg CO_2-eq./MWh
- Emission factor for CHP power output = (3020 kg CO_2-eq./hr)/8 MW = 377.5 kg CO_2-eq./MWh

13.0 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.

13.1 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. If companies use fuel consumption statistics to estimate CO_2 emissions, the estimates are derived using the same approach and emission factors as used for stationary fossil fuel combustion sources (Section 8.1).

Emission factors for CH_4 and N_2O for on-road sources can be found in IPCC 1997c. A variety of parameters affect CH_4 and N_2O emissions from on-road vehicles, including type of vehicle, fuel consumed, operating characteristics, emission controls, maintenance procedures, and fleet age. The impacts of these parameters are reflected in the tables of emission factors for on-road vehicles included in IPCC 1997c. In general, CH_4 and N_2O emission factors for gasoline-fueled on-road vehicles, combined and expressed in terms of CO_2-equivalents, range from 1.2 to 13.5 kg/GJ with a median value of 4.6 kg/GJ. Diesel-fueled sources are associated with somewhat lower CH_4 and N_2O emission factors, which range from 0.6 to 4.4 kg CO_2-equiv/GJ, with a median value of 1.0 kg CO_2-equiv/GJ. For context, CO_2 emission factors for liquid transportation fuels are usually close to 70 kg CO_2/GJ.

The emission factors in IPCC 1997c demonstrate that for some types of on-road transportation sources CH_4 and N_2O emissions represent only a small fraction of overall GHG emissions, whereas they can be more significant for other types of transportation sources. The guidance provided in WRI 2004d only addresses CO_2 emissions from transportation sources, presumably due to the difficulty in assessing CH_4 and N_2O emissions and the small contribution to overall GHG emissions they represent for many of these sources.

It should be recognized that use of distance-based emission factors may result in less accurate emission estimates than those computed based on actual fuel consumption data. If, however, the company finds it more convenient to develop emissions estimates from statistics on distance traveled the CO_2 emission factors in WRI 2004d (reproduced in Annex C) can be used. The WRI/WBCSD GHG Protocol does not provide CH_4 nor N_2O emission factors for transportation sources.

13.2 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 CO_2 emissions from these sources using the emission factors in Table 2. CH_4 and N_2O emissions can be a notable fraction of the GHG emissions from some of these sources. N_2O emissions for some of these sources are reported to be near 30 g/GJ or 9 kg CO_2-equiv./GJ, which can amount to more than 10% of the CO_2 emissions from such sources.

Emission factors for mobile sources have been published in a number of places. Some of the available information is summarized in Annex C. 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. The CO_2 factors in the table are from Table 2 and are slightly different than those in the original table in IPCC 1997c due to correction for unoxidized carbon, using the IPCC recommendations. Table 9 also includes overall CO_2-equivalent emission factors developed using the IPCC global warming potentials for CH_4 (21) and N_2O (310).

The published emission factors for CH_4 and N_2O from mobile sources vary from one protocol to another. The differences in N_2O, in particular, can impact the CO_2-equivalents by as much as 10%. Where companies need precise estimates for these sources, it is recommended that the various sources discussed in Annex C be examined to determine which emission factors are most appropriate. In most cases, however, the emission factors in Table 9 will be adequate.

Table 9. Emission Factors for Non-Road Mobile Sources and Machinery (IPCC 1997c) (IPCC Revised 1996 Guidelines taken from EMEP/CORINAIR)

Source and Engine Type	CO_2 kg/TJ	CH_4 kg/TJ	N_2O kg/TJ	CO_2-equiv. kg/TJ
Forestry – diesel	73,400*	4	30	82,800
Industry – diesel	73,400*	4	30	82,800
Railways – diesel	73,400*	4	30	82,800
Inland waterway – diesel	73,400*	4	30	82,800
Marine – diesel	73,400*	7	2	74,200
Industry – gasoline 4-stroke	68,600*	50	2	70,300
Forestry – gasoline 2-stroke	68,600*	170	0.4	72,300
Industry – gasoline 2-stroke	68,600*	130	0.4	71,500
Inland waterway – gasoline 4-stroke	68,600*	40	2	70,100
Inland waterway – gasoline 2-stroke	68,600*	110	0.4	71,000

* From Table 2, corrected for unburned carbon

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

Based on purchasing records, a mill 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 mill's emissions. Rather than trying to develop a more accurate estimate, the mill 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: 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 mill:

- 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/l and the heat content of the diesel fuel is 0.038 GJ/l.
The company decides to use the CO_2-equivalent emission factors in Table 9 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/liter = 306 GJ/y = 0.306 TJ/y
- 0.306 TJ/y x 70,300 kg CO_2-equiv./TJ = 21,500 kg CO_2-equiv./y = 21.5 t CO_2-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/liter = 34 GJ/y = 0.034 TJ/y
- 0.034 TJ/y x 72,300 kg CO_2-equiv./TJ = 2460 kg CO_2-equiv/y = 2.5 t CO_2-equiv./y

- Diesel used = 200,000 l/y
- 200,000 l/y * 0.038 GJ/l = 7600 GJ/y = 7.6 TJ/y
- 7.6 TJ/y x 82,800 kg CO_2-equiv./TJ = 629,000 kg CO_2-equiv./y = 629 t CO_2-equiv./y

Total GHG emissions from company-owned forestry operations and wood trucks

- 21.5 + 2.5 + 629 = 653 t CO_2-equiv./y

14.0 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 mill's process waste is being disposed in a municipal solid waste landfill and the company is interested in estimating the mill'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 14.2.1 and 14.2.2.

As is the case with most widely accepted protocols, only CH_4 emissions are addressed in these tools because CO_2 from landfills is composed of biomass carbon and N_2O 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 mill waste. The emission factor can be useful in deciding whether landfill emissions are material to the results of the inventory. The methods described herein, however, are recommended for preparing an estimate to use in the inventory results.

14.1 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 mill with a capped landfill has determined that its collection system collects 90 tons of methane per year and the mill 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 mill 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 CO_2 and therefore is not included in GHG totals.

Using these default values and assumptions, estimates of methane releases can be developed using Equation 7.

$$CH_4\ (m^3/y)\ \text{released to the atmosphere} = [(REC / FRCOLL) * (1 - FRCOLL) * FRMETH * (1 - OX)] + [REC * FRMETH * (1 - FRBURN)] \qquad \text{(Eq. 7)}$$

where: REC = amount of landfill gas collected, determined on a site-specific basis, m^3/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

14.2 Estimating Methane Emissions at Landfills without Gas Collection Data

14.2.1 *Simplified First Order Decay Approach*

Where the approach described in Section 14.1 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 pulp and paper mill landfills. 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 CH_4 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 (e.g., a new deinking mill is built on-site) 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.

$$CH_4\ (m^3/y)\ \text{generated from all waste in the landfill} = R\ L_0\ (e^{-kC} - e^{-kT}) \qquad \text{(Eq. 8)}$$

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.)

Where companies can separate the quantities of inert wastes (e.g., boiler ash, concrete) 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 8 in Equation 9. 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).

$$CH_4\ (m^3/y)\ \text{released} = [(CH_4\ \text{generated} - CH_4\ \text{recovered}) * (1 - OX)] + [CH_4\ \text{recovered} * (1 - FRBURN)] \quad (\text{Eq. } 9)$$

where: CH_4 *generated = from Equation 8*
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 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 14.2.2.

Annex D identifies a number of sources for the parameter values L_0 and k needed in Equation 8. Unfortunately, the values vary considerably from one protocol to the next and are based on very few data. For situations where pulp and paper mill 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 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 should use the parameter values shown in Table 10. Annex D 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 Landfill Methane Emissions

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

14.2.2 *Detailed First Order Decay Approach*

To allow year-to-year variations in the amounts of waste sent to a landfill, IPCC suggests a variation of this approach. Starting in year one, calculate how much methane will be generated in each subsequent year by waste deposited in that year using Equations 10 and 11.

$$CH_4 \text{ generated in a given year by waste deposited in an earlier year } (m^3/y) = k\, R_y\, L_0\, (e^{-k[T-Y]}) \qquad \text{(Eq. 10)}$$

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.

$$CH_4 (m^3/y) \text{ released} = [(CH_4 \text{ generated} – CH_4 \text{ recovered}) * (1–OX)] + [CH_4 \text{ recovered} * (1-FRBURN)] \qquad \text{(Eq. 11)}$$

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 estimate the quantities of inert wastes separately (e.g., boiler ash, concrete) 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 mill 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.

Example Calculation: Emissions from a mill 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 m^3/y and the gas is 47% methane by volume. The mill 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 m^3/y x 0.47 = 385,000 m^3/y
- methane generated = (385,000 m^3/y) / 0.75 = 513,000 m^3/y
- methane released = (513,000 – 385,000)m^3/y x (1- 0.1) = 115,000 m^3/y = 115 x 10^6 l/y
- methane released = (115 x 10^6 l/y) / 22.4 l/g-mole = 5.13 x 10^6 g-mole/y
- methane released = (5.13 x 10^6 g-mole/y) x 16 g/g-mole = 82 x 10^6 g/y = 82 t CH_4/y

Using the IPCC GWP (21), this is equal to 1720 t CO_2-equiv./y

Example calculation: Emissions from 20 year old landfill receiving mill wastewater treatment solids and ash. The landfill does not have a gas collection system.

A mill landfills 50 ton per day of solid waste composed primarily of wastewater treatment plant solids, ash, and other miscellaneous waste typical of a kraft mill. The mill 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 mill uses the default values for k and L_0 shown in Table 10 (100 m^3/Mg for L_0 and 0.03 y^{-1} for k).

R = 50 Mg/d x 350 d/y = 17500 Mg/y
L_0 = 100 m^3/Mg
k = 0.03/y
C = 0 y
T = 20 y

- methane generated (m^3/y) = 17,500 x 100 x ($e^{-0.03 \times 0} - e^{-0.03 \times 20}$) = 790,000 m^3/y
- density of methane (0°C and 1 atm. pressure) = 0.72 kg/m^3 (from Perry's Chemical Engineers' Handbook)
- methane generated (kg/y) = 790,000 m^3/y x 0.72 kg/m^3 = 568,000 kg/y = 568 t/y
- assume 10% oxidation in landfill cover
- methane released = 568 t/y x (1 – 0.1) = 511 t CH_4 /y released

Using the IPCC GWP (21), this equals 10,700 t CO_2-equiv./y

Note that the Table 1 emission factor would have yielded an estimate of 50 t/d x 350 d/y x 3,500 kg/t = 61,250,000 kg/y = 61,250 t CO_2-equiv./y, over five times the estimate developed using the more refined approach.

15.0 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 CH_4 emissions need to be estimated. The CH_4 emissions from company-owned anaerobic systems will be reported as direct emissions. The CO_2 emitted from wastewater and sludge treatment operations contains biomass carbon which is not included in GHG totals. Where this biomass CO_2 is not combustion related (e.g., it is not formed from combustion of methane), it is often excluded from inventory results altogether. In addition, N_2O emissions from treatment plants have been found to be small, and probably occur only after the wastewater is discharged (IPCC 1997c).

15.1 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 CO_2 produced in burning the CH_4 contains biomass carbon, it does not need to be reported in GHG inventory totals. If circumstances at a mill suggest that non-trivial amounts of methane are escaping collection, the mill may need to undertake efforts to account for these releases, but such circumstances are expected to be unusual at mills 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.

15.2 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 12 (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 be estimated only from anaerobic treatment or sludge digestion systems until factors for other types of systems are available.

$$\text{Anaerobic Treatment Plant Methane Emissions (kg/y)} = (OC \times EF) - B \quad \text{(Eq. 12)}$$

where: *OC = BOD or COD of the feed to the anaerobic system, kg/year*
EF = emission factor, default values = 0.25 kg CH_4/kg COD in the feed or 0.6 kg CH_4/kg BOD in the feed (or another BOD-based factor developed by multiplying the COD-based factor of 0.25 kg CH_4/kg COD by the site-specific COD/BOD ratio)
B = methane captured and burned, kg CH_4/year, determined on a site-specific basis

If the solids are handled separately, emissions from sludge digestion would be calculated using Equation 13. In cases where sludge is burned, it is included in the calculations for GHG emissions from biomass burning discussed in Section 11.

$$\text{Anaerobic Sludge Digestion Plant Methane Emissions (kg/y)} = (OCs \times EFs) - B \quad \text{(Eq. 13)}$$

where: *OCs = organic content of the sludge*
EFs = emission factor, in units consistent with OCs - IPCC's default value is 0.25 kg CH_4/kg COD in the sludge feed
B = methane captured and burned, kg CH_4/yr, determined on a site-specific basis

Example calculation: Recycled paperboard mill with anaerobic treatment but no gas recovery.

A recycled paperboard mill uses an anaerobic treatment plant to treat wastewater containing 10,000 kg COD/d. The mill generates wastewater 300 days per year. The IPCC default value for CH_4 generation from anaerobic treatment systems is 0.25 kg CH_4/kg COD in the feed. The CH_4 emissions are calculated as follows.

- OC = 10,000 kg/d x 300 d/y = 3,000,000 kg COD/y
- CH_4 generated = 3,000,000 kg COD/y x 0.25 kg CH_4/kg COD = 750,000 kg CH_4/y

= 750 t CH_4/y
Using the IPCC GWP (21), this equals 15,750 t CO_2-equiv./y

16.0 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. 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 format 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 CO_2. Companies are encouraged to use this or a similar format 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 mill inventory. The schematic presented in Figure 1 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 CO_2 from biomass combustion, separate from direct GHG emissions. Annex E includes tables (Tables E1 and E2) 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.

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. *Attach additional pages if needed.*	Mark to identify operations included in the inventory
Harvesting	
Wood/chip/bark/wastepaper/other raw material transportation vehicles	
Product, by-product or waste transportation vehicles	
Debarking	
Chipping	
Mechanical pulping	
Chemical pulping – kraft	
Chemical pulping – sulfite	
Chemical pulping – other	
Semichemical pulping	
Recovery furnace – kraft	
Liquor furnace – sulfite	
Liquor furnace – semichem	
Lime kiln or calciner	
Incinerators for non-condensable gases, etc.	
Wastepaper pulping and cleaning	
Deinking	
Bleaching of chemical or semichemical pulp	
Brightening of deinked pulp	
On-site preparation of chemicals (e.g., ClO_2 or O_3)	
Paper and/or paperboard production	
Coating (including extrusion coating)	
Roll trimming, roll wrapping, sheet cutting	
On-site power and steam boilers	
On-site combustion turbines	
Gas-fired infrared dryers	
Other fossil fuel-fired dryers	
Wastewater treatment operations	
Sludge processing	
Landfill receiving mill waste	
Air emissions control devices	
On-road vehicles	
Off-road vehicles and machinery	
Normal offices/workspace for mill 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_2O	CO_2 Equiv [1]
	Process and Energy-Related Emissions				
1	Stationary Fossil Fuel Combustion				
2	Biomass Combustion	N/A*			
3	Make-up Chemicals ($CaCO_3$ and Na_2CO_3)				
	Transportation and machinery emissions				
4	On-road vehicles				
5	Off-road vehicles and machinery				
	Waste management emissions				
6	Landfill emissions from mill wastes	N/A*			
7	Anaerobic wastewater treatment systems	N/A*			
8	*Other Direct Emissions not included above – Explain:*				
	Total Direct Emissions (Sum of lines 1 through 8)				
	Emissions associated with exported electricity and steam *(a subset of total direct emissions)*				
9	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:				
10	Emissions related to steam exports				
11	*Total emissions attributable to exports (Sum of lines 9 and 10)*				

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] *CO_2-equivalents are calculated multiplying individual gases by IPCC GWP values, CO_2=1, CH_4=21, N_2O=310, and summing across all three gases. It is acceptable to use emission factors for CO_2-equivalents rather than estimating the three gases individually.*

*N/A – Not Applicable - carbon dioxide emissions from biomass are not included in GHG totals because this carbon is considered 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-CO_2

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_2O	CO_2 Equiv [1]
Indirect emissions related to electricity and steam imports, including those from outsourced power islands					
1	Indirect Emissions related to electricity imports that are consumed				
2	Indirect Emissions related to steam imports that are consumed				
3	*Total indirect emissions from power/steam imports (Sum of lines 1 through 2)*				
Other Indirect Emissions					
4	Description of other indirect emissions included in inventory:				
Imports and Exports of fossil fuel-derived CO_2					
5	Imports of CO_2 (e.g., for neutralization)				
6	Exports of fossil fuel-derived CO_2 (e.g., to PCC Plants)				
	Note 1: This includes only the fraction of CO_2 exports that can be traced to fossil fuels. Exports of biomass-derived CO_2 are reported in Annex E – Supporting Information on Biomass. Note 2: This exported CO_2 should *not* be reported as an emission in Table 12.				

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] *CO_2-equivalents are calculated multiplying individual gases by IPCC GWP values, CO_2=1, CH_4=21, N_2O=310, and summing across all three gases. It is acceptable to use emission factors for CO_2-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_2O	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[*]				
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 GHG totals because this carbon is considered 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.

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. *Attach additional pages if needed.* Small amounts of purchased power for a third party waste paper sorting operation are included in the mill's inventory results. Also, an on-site gas turbine CHP system owned by another company supplies the mill 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 mill is down, we sometimes continue to generate biomass power in mill-owned condensing turbines and sell it to the grid.	Mark to identify operations included in the inventory
Harvesting	X
Wood/chip/bark/wastepaper/other raw material transportation vehicles	X
Product, by-product or waste transportation vehicles	
Debarking	X
Chipping	X
Mechanical pulping	
Chemical pulping – kraft	X
Chemical pulping – sulfite	
Chemical pulping – other	
Semichemical pulping	
Recovery furnace – kraft	X
Liquor furnace – sulfite	
Liquor furnace – semichem	
Lime kiln or calciner	
Incinerators for non-condensable gases, etc.	X
Wastepaper pulping and cleaning	X
Deinking	X
Bleaching of chemical or semichemical pulp	X
Brightening of deinked pulp	X
On-site preparation of chemicals (e.g., ClO_2 or O_3)	X
Paper and/or paperboard production	X
Coating (including extrusion coating)	X
Roll trimming, roll wrapping, sheet cutting	X
On-site power and steam boilers	X
On-site combustion turbines	
Gas-fired infrared dryers	X
Other fossil fuel-fired dryers	X
Wastewater treatment operations	X
Sludge processing	X
Landfill receiving mill waste	X
Air emissions control devices	X
On-road vehicles	X
Off-road vehicles and machinery	X
Normal offices/workspace for mill employees	X
Other Operation – describe: On site commercial wastepaper collection and sorting operation	
Other Operation – describe:	
Other Operation – describe:	

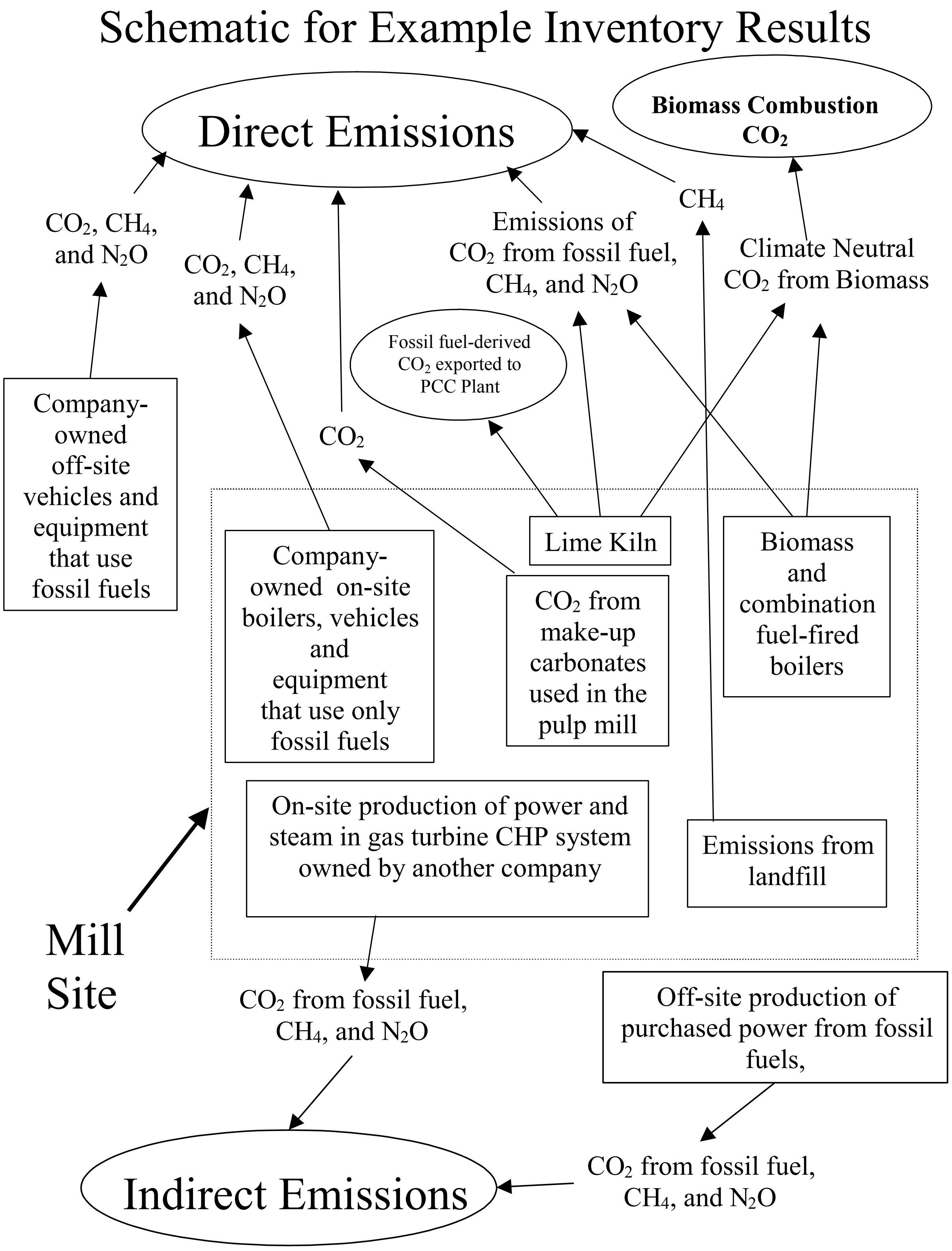


Figure 1. Schematic for Example Inventory Results

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_2O	CO_2 Equiv [1]
	Process and Energy-Related Emissions				
1	Stationary Fossil Fuel Combustion	720000	100	80	746900
2	Biomass Combustion	N/A[*]	120	40	14920
3	Make-up Chemicals ($CaCO_3$ and Na_2CO_3)	5500	0	0	5500
	Transportation and machinery emissions				
4	On-road vehicles	>>>	>>>	>>>	320
5	Off-road vehicles and machinery	NM[†]	NM[†]	NM[†]	NM[†]
	Waste management emissions				
6	Landfill emissions from mill wastes	N/A[*]	511		10730
7	Anaerobic wastewater treatment systems	N/A[*]			NA
8	*Other Direct Emissions not included above – Explain:*				
	Total Direct Emissions (Sum of lines 1 through 8)	>>>	>>>	>>>	778370

Emissions associated with exported electricity and steam
(a subset of total direct emissions)

9	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:				
10	Emissions related to steam exports	0	0	0	0
11	*Total emissions attributable to exports (Sum of lines 9 and 10)*	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 mill's emissions. They are therefore reported as non-material (NM).

[1] *CO_2-equivalents are calculated multiplying individual gases by IPCC GWP values, CO_2=1, CH_4=21, N_2O=310, and summing across all three gases. It is acceptable to use emission factors for CO_2-equivalents rather than estimating the three gases individually.*

[*] N/A – Not Applicable - carbon dioxide emissions from biomass are not included in GHG totals because this carbon is considered 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-CO_2

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_2O	CO_2 Equiv [1]
Indirect emissions related to electricity and steam imports, including those from outsourced power islands					
1	Indirect Emissions related to electricity imports that are consumed	>>>	>>>	>>>	72000
2	Indirect Emissions related to steam imports that are consumed	>>>	>>>	>>>	12400
3	*Total indirect emissions from power/steam imports (Sum of lines 1 through 2)*				84400
Other Indirect Emissions					
4	Description of other indirect emissions included in inventory:				0
Imports and Exports of fossil fuel-derived CO_2					
5	Imports of CO_2 (e.g., for neutralization)	0			
6	Exports of fossil fuel-derived CO_2 (e.g., to PCC Plants) Note 1: This includes only the fraction of CO_2 exports that can be traced to fossil fuels. Exports of biomass-derived CO_2 are reported in Annex E – Supporting Information on Biomass. Note 2: This exported CO_2 should *not* be reported as an emission in Table 12.	21000			

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] *CO_2-equivalents are calculated multiplying individual gases by IPCC GWP values, CO_2=1, CH_4=21, N_2O=310, and summing across all three gases. It is acceptable to use emission factors for CO_2-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_2O	CO_2 Equiv	Source of EF
Fossil Fuel Combustion						
Fuel	*Combustion Units*					
Gasoline	forestry equip.				66.8 tonne/TJ HHV	Table 9
Diesel fuel	trucks and machinery				78.6 tonne/TJ HHV	Table 9
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	boiler	50.2 tonne/ TJ HHV	5 kg/TJ HHV	0.1 kg/TJ HHV		Tables 2 (corrected for unoxidized C) and 5
Biomass Combustion						
Fuel	*Combustion Units*					
bark & wood residual fuels	boiler	N/A*	11 kg/TJ HHV	4 kg/TJ HHV		Table 8
		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 m^3/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 GHG totals because this carbon is considered 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 KRAFT MILL LIME KILNS AND CALCINERS

There has been considerable confusion about the correct way to estimate GHG emissions from kraft mill lime kilns and calciners. Some of the approaches suggested by the protocols included in this review are presented in this section. In addition, it contains a discussion of the correct approach for estimating these emissions. The correct approach is to include only CO_2 emissions associated with the fossil fuels burned in the kiln or calciner, and CH_4 and N_2O emissions if deemed material to the inventory.

1.0 EXISTING PROTOCOLS

Environment Canada, in *Canada's Greenhouse Gas Inventory, 1990-2002*, states that "[e]missions from the regeneration of lime from spent pulping liquors at pulp mills are not accounted for in the Industrial Processes Sector. Since this CO_2 is biogenic in origin, it is recorded as a change in forest stock in the [Land Use Change and Forestry] Sector" (Environment Canada 2004, p. 56).

IPCC appears to imply that CO_2 emissions from kraft mill lime kilns and calciners should be included in GHG inventories when it states that "[i]ndustries that regenerate lime from waste calcium carbonates (e.g., wood pulp and paper plants) are unlikely to report their lime production. Omission of these data may lead to an underestimation of lime production for a country…" (IPCC 2000, p. 3.23). The question of whether CO_2 should be included, however, is not directly addressed. IPCC suggests emission factors of 1.0 and 1.1 kg CH_4/TJ for oil-fired and gas-fired lime kilns, respectively (IPCC 1997c, Table 1-17). These factors were not developed for kraft mill lime kilns, however.

EPA implies that CO_2 evolved during calcination of kraft pulping lime mud should not be included in GHG inventories. In *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2002* (USEPA 2004, p. 123) EPA states that:

> In some cases, lime is generated from calcium carbonate by-products at pulp mills and water treatment plants. The lime generated by these processes is not included in the USGS data for commercial lime consumption. In the pulping industry, mostly using the Kraft (sulfate) pulping process, lime is consumed in order to causticize a process liquor (green liquor) composed of sodium carbonate and sodium sulfide. The green liquor results from the dilution of the smelt created by combustion of the black liquor where biogenic carbon is present from the wood. Kraft mills recover the calcium carbonate "mud" after the causticizing operation and most sulfate mills recover the waste calcium carbonate after the causticizing operation and calcine it back into lime–thereby generating CO_2 for reuse in the pulping process. Although this re-generation of lime could be considered a lime manufacturing process, the CO_2 emitted during this process is mostly biogenic in origin, and therefore would not be included in Inventory totals.

2.0 CORRECTLY ACCOUNTING FOR GREENHOUSE GAS EMISSIONS FROM KRAFT MILL LIME KILNS AND CALCINERS

2.1 Carbon Dioxide

NCASI recently examined the question of GHG emissions from lime kilns (Miner and Upton 2002). Much of the following discussion is taken from that paper.

The recovery and reuse of pulping chemicals is essential to the kraft pulping process. The recovery process involves two interconnected loops, depicted in Figure A1. These can be thought of as a sodium loop and a calcium loop. In the sodium loop, white liquor, a mixture of sodium hydroxide and sodium sulfide, is added to wood chips in a pulping digester. This process results in most of the non-fibrous material being dissolved from the wood. The digester is discharged at the end of the pulping process, yielding a combination of wood fiber and a spent pulping liquor called black liquor because of the very dark color imparted by the dissolved lignin-derived material. The black liquor, which also contains the spent pulping chemicals, is separated from the wood fibers by washing, concentrated by evaporation, and then sent to a recovery furnace where it is burned under controlled conditions.

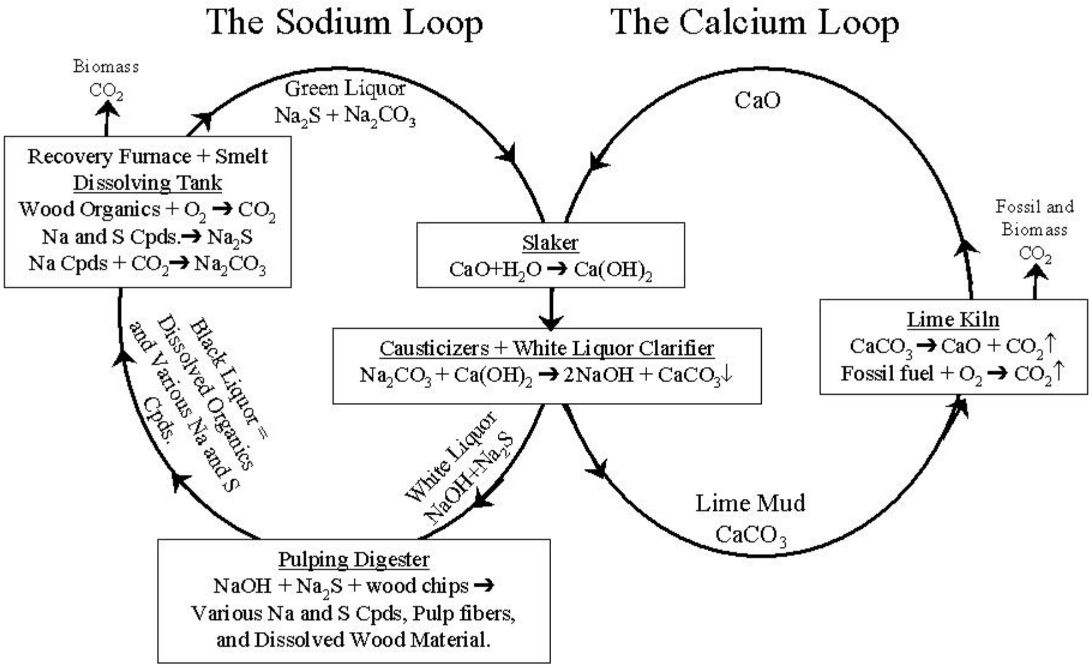


Figure A1. A Simplified Representation of the Kraft Pulping and Chemical Recovery System

The recovery furnace produces large amounts of steam which are used throughout the mill. In addition, due to the controlled oxygen deficient conditions in the bottom of the furnace, a molten smelt consisting primarily of sodium carbonate and sodium sulfide is produced. The sodium sulfide is formed in the recovery furnace by the reduction of a variety of sulfur compounds in the black liquor. The sodium carbonate is formed by the reaction of sodium compounds (primarily sodium oxide and sodium sulfide) with CO_2, a product of combustion of the wood-derived material in the black liquor (i.e., biomass).

Molten smelt is discharged from the bottom of the recovery furnace and dissolved in water to produce green liquor. Subsequently, the sodium carbonate in the green liquor is converted into sodium hydroxide by reacting with calcium hydroxide in causticizers, producing a calcium carbonate precipitate. White liquor, the combination of sodium hydroxide and sodium sulfide needed for pulping, is produced by removing the precipitate. In this way the sodium loop is closed. Because small amounts of sodium are lost, mills commonly make up this loss by adding sodium carbonate, sodium sulfate, or sodium hydroxide, depending on whether the mill needs the additional sulfur and the capacity of various processes in the recovery system.

The calcium loop intersects the sodium loop at the causticizers. In the causticizers, calcium carbonate ($CaCO_3$) is formed by the reaction of calcium hydroxide with the sodium carbonate in green liquor. The carbon contained in this calcium carbonate originated in the wood, was converted to biomass CO_2 in the recovery furnace, subsequently reacted with sodium salts in the recovery furnace to form sodium carbonate, and was finally converted to calcium carbonate in the causticizers. In essence, therefore, the reactions in the causticizers accomplish a transfer of biomass carbon from the sodium loop to the calcium loop.

The calcium carbonate formed in the causticizers is separated from the white liquor, dewatered (forming a material called lime mud), and washed before being burned in a lime kiln or calciner to produce calcium oxide. The CO_2 liberated in the conversion of calcium carbonate to calcium oxide in the lime kiln contains carbon which originated in wood and was transported to the calcium loop via the sodium carbonate in green liquor.

Therefore, except in cases where $CaCO_3$ is added to the recovery system as a make-up chemical, the only CO_2 that should be included in GHG inventories is that amount from fossil fuels burned in the kiln or calciner. Elsewhere in this report, there is additional discussion of GHG emissions that may sometimes be related to carbonate-containing make-up chemicals used by some mills.

2.2 Methane

Small amounts of methane have been found in lime kiln emissions at some kraft mills. Sampling at three mills in the late 1970s found that methane concentrations were usually less than 1 ppm by volume, although values has high as 34 ppm were measured (NCASI 1980). Of 73 measurements made at the three mills, all but 7 were less than 5 ppm. For these three mills, 5 ppm corresponded to approximately 0.004 kg methane per metric ton of pulp. At an assumed lime kiln fuel consumption rate of 1.5 GJ/ton pulp, this is equal to 2.7 kg CH_4/TJ.

IPCC suggests emission factors of 1.0 and 1.1 kg CH_4/TJ for oil-fired and gas-fired lime kilns, respectively. (IPCC 1997c, Table 1-17). These factors were not developed for kraft mill lime kilns, however.

Although the data are limited and old, the NCASI emission factor of 2.7 kg CH_4/TJ is probably more appropriate for estimating methane emissions from kraft mill lime kilns than the IPCC emission factors for commercial kilns. The emission factor is likely to be revised, however, as new data are generated.

2.3 Nitrous Oxide

Because nitrous oxide is formed in some combustion processes, it is appropriate to examine the potential for nitrous oxide emissions from kraft mill lime kilns. This gas is potentially important because it is usually assumed to have a greenhouse gas global warming potential 310 times greater than CO_2. IPCC reviewed the literature and concluded that formation of nitrous oxide is unlikely outside a range of combustion temperatures of approximately 538°C to 927°C (1000°F to 1700°F) (IPCC 1997c). The calcination of lime commences at approximately 816°C (1500°F) and, in a lime kiln, normally involves temperatures in the range of 980°C to 1200°C (1800°F to 2200°F) (Hough 1985). Heating calcium solids to these temperatures in a lime kiln requires combustion temperatures above the range thought to be suitable for nitrous oxide formation. Kraft mill lime kilns, therefore, are not expected to be a significant source of nitrous oxide.

Some mills use calciners instead of kilns to regenerate lime. Because calciners operate at lower temperatures (maximum temperature of about 870°C or 1600°F) there appears to be a potential for N_2O generation, but data are lacking (Hough 1985).

It is reasonable, therefore, to assume that N_2O emissions from lime kilns are so low that they need not be reported. In the case of calciners, however, this assumption may not be reasonable, but there are no data so it is suggested that the N_2O emission factors for comparable-sized fossil fuel boilers be used (see Annex A).

2.4 Use of Kraft Mill Lime Kiln Gases to Manufacture Precipitated Calcium Carbonate

Calcium carbonate pigment can be used as a coating and filler material in the production of some grades of paper and paperboard. Calcium carbonate pigment is manufactured by grinding limestone or marble, or by chemical precipitation. At some mills, the correct characterization of lime kiln emissions is complicated by the now-common practice of using the lime kiln stack gas CO_2 (or gas from another boiler) to manufacture precipitated calcium carbonate (PCC) at satellite plants. The PCC manufacturing process involves the reaction of CO_2-rich lime kiln gas with purchased calcium oxide (lime) to produce PCC. Although other mill stack gases are sometimes used, the lime kiln stack is favored, primarily because of its higher CO_2 content.

While the amounts of CO_2 used in PCC manufacturing at satellite plants appear to be small compared to the industry's overall emissions, the quantities can be significant at individual mills because 50% or more of the CO_2 in the stack gas can be consumed in the PCC manufacturing process. Indeed, some kraft mills use biomass to supply almost all of their energy needs, with the only significant use of fossil fuel being the lime kiln. At such mills, the amounts of CO_2 captured in PCC manufacture can actually exceed the amounts of fossil CO_2 emitted by the mill.

Because the CO_2 exported to PCC plants is not emitted by the mill nor by any source owned by the company, this CO_2 is reported as an export rather than an emission. Where CO_2 is exported from lime kilns, the gas consists of a combination of fossil fuel-derived CO_2 and biomass-derived CO_2. In the suggested reporting format for the calculation tools, these two types of CO_2 exports are reported separately. The data on exports of fossil fuel-derived CO_2 are reported with other data on fossil fuel-derived CO_2 and the exports of biomass-derived CO_2 can be reported in Annex E (CO_2 from biomass combustion).

With respect to PCC manufactured from mill GHG emissions, it is important to note that the calculation tools are intended to help characterize a facility's or company's greenhouse gas emissions and not the fate of those emissions. Nor are they intended to address the life cycle tradeoffs associated with use of mill emissions as a raw material in PCC manufacture. These are questions that require a much broader analysis than is possible within the scope of this inventory guidance.

ANNEX B

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 12.6 of *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills, version 1.1* 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 mill owns the CHP system and uses all of its output, this is not necessary because all the emissions are direct emissions for the mill. In many cases, however, a mill may either receive CHP energy from an outside provider or export a portion of its own CHP output. For instance, if a mill 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 three methods recommended by WRI/WBCSD (WRI 2004b,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 12.6.1 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 is 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 recommended for mills that lack, or choose not to use, detailed design and operating data from CHP systems.

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

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:

$$E_P = E_T - E_H \qquad \textit{(Eq. 2)}$$

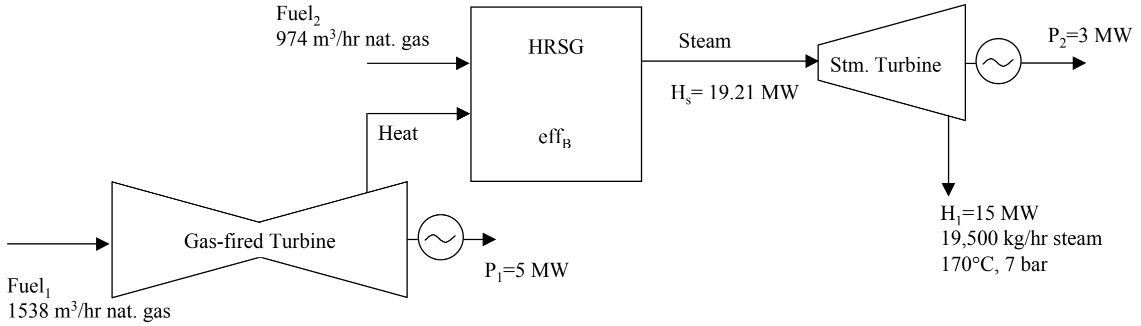
where: E_P *= emissions share attributable to electric power production*

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, 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 below makes use of these recommended default efficiency factors.

Example Calculation: Allocating CHP emissions to three output streams – Simplified efficiency method with WRI/WBCSD recommended default efficiency factors for the US.

A mill has the CHP system shown in the following 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 by WRI/WBCSD for the US; 0.35 for power generation and 0.8 for steam generation (WRI 2004b, c).



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:

Fuel$_1$:
CO_2 (1538 m^3/hr) x (0.039 GJ/m^3) x (55.9 kg CO_2/GJ) = 3353 kg CO_2/hr
CH_4 (1538 m^3/hr) x (0.039 GJ/m^3) x (0.0006 kg CH_4 /GJ) x (21 CO_2-eq. / CH_4)
= 0.76 kg CO_2-eq./hr
N_2O (1538 m^3/hr) x (0.039 GJ/m^3) x (0.0001 kg N_2O /GJ) x (310 CO_2-eq. / N_2O)
= 1.86 kg CO_2-eq/hr
Total Fuel$_1$ emissions = 3356 kg CO_2-eq./hr

Fuel$_2$:
CO_2 (974 m^3/hr) x (0.039 GJ/m^3) x (55.9 kg CO_2/GJ) = 2123 kg CO_2/hr
CH_4 (974 m^3/hr) x (0.039 GJ/m^3) x (0.0014 kg CH_4 /GJ) x (21 CO_2-eq. / CH_4)
= 1.12 kg CO_2-eq./hr
N_2O (974 m^3/hr) x (0.039 GJ/m^3) x (0.0001 kg N_2O /GJ) x (310 CO_2-eq. / N_2O)
= 1.18 kg CO_2-eq./hr
Total Fuel$_2$ emissions = 2126 kg CO_2-eq./hr

Total CHP system emissions = 3356 + 2126 = 5482 kg CO_2-eq./hr

Total system power output = $P_1 + P_2$ = 8 MW

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

$E_H = \left\{ \dfrac{15MW}{15MW + \left(8MW \times 2.3\right)} \right\} \times 5482 kgCO_2eq = 2462 kgCO_2eq$ = 20,681 t CO_2 eq/y at 350 d/y operation

$E_P = 5482 kgCO_2eq - 2462 kgCO_2eq = 3020 kgCO_2eq$ = 25,368 t CO_2 eq/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*2462/5482 = 44.9%
- Percentage of CHP emissions to power output = 100*3020/5482 = 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 = (2462 kg CO_2-eq./hr)/15 MW
  = 164.1 kg CO_2-eq./MWh
- Emission factor for CHP power output = (3020 kg CO_2-eq./hr)/8 MW
  = 377.5 kg CO_2-eq./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:

$$E_{H1} = \left\{ \frac{\left(\dfrac{H_1}{e_{H1}}\right)}{\left(\dfrac{H_1}{e_{H1}}\right) + \left(\dfrac{H_2}{e_{H2}}\right) + \ldots + \left(\dfrac{P_1}{e_{P1}}\right) + \left(\dfrac{P_2}{e_{P2}}\right) + \ldots} \right\} \times E_T \qquad \text{(Eq. 3)}$$

$$E_{P1} = \left\{ \frac{\left(\dfrac{P_1}{e_{P1}}\right)}{\left(\dfrac{H_1}{e_{H1}}\right) + \left(\dfrac{H_2}{e_{H2}}\right) + \ldots + \left(\dfrac{P_1}{e_{P1}}\right) + \left(\dfrac{P_2}{e_{P2}}\right) + \ldots} \right\} \times E_T \qquad \text{(Eq. 4)}$$

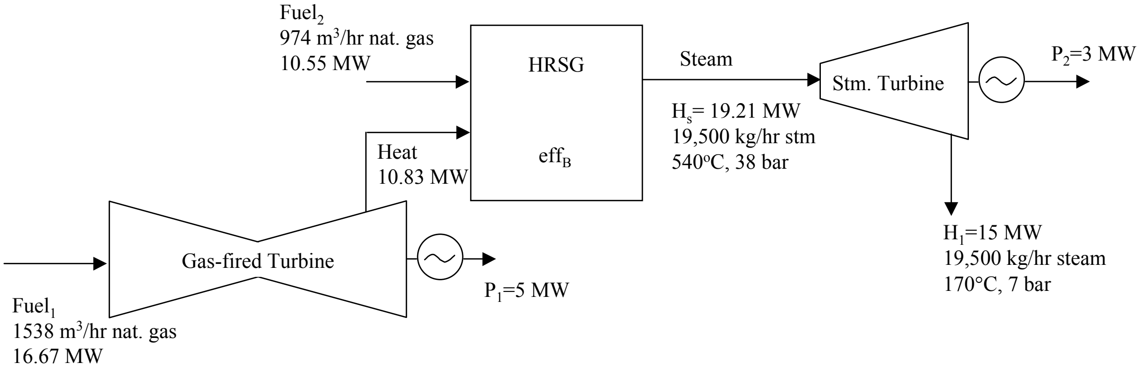
Where: E_{H1} *= emissions share attributable to heat production as contained in steam stream 1*
E_{P1} *= emissions share attributable to electric power production via generator 1*
E_T *= total emissions from the CHP plant*
H_1 *= heat output contained in steam stream 1*

H_2 = *heat output contained in steam stream 2*
P_1 = *power output from generator 1*
P_2 = *power output from generator 2*
e_{H1} = *overall efficiency of producing heat contained in steam stream 1*
e_{H2} = *overall efficiency of producing heat contained in steam stream 2*
e_{P1} = *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.

Figure 1 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 Fuel$_1$ emissions = 3356 kg CO_2-eq./hr
Total Fuel$_2$ emissions = 2126 kg CO_2-eq./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:

$$E_{P1} = \left\{ \frac{\left(\frac{P_1}{e_{P1}}\right)}{\left[\left(\frac{P_1}{e_{P1}}\right) + \left(\frac{Heat}{e_{Heat}}\right)\right]} \right\} \times E_{F1} = \left\{ \frac{\left(\frac{5MW}{0.3}\right)}{\left[\left(\frac{5MW}{0.3}\right) + \left(\frac{10.83MW}{0.65}\right)\right]} \right\} \times 3356 kgCO_2 eq = 1678 kgCO_2 eq$$

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[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.

$$E_{Heat} = \left\{ \frac{\left(\frac{Heat}{e_{Heat}}\right)}{\left[\left(\frac{P_1}{e_{P1}}\right) + \left(\frac{Heat}{e_{Heat}}\right)\right]} \right\} \times E_{F1} = \left\{ \frac{\left(\frac{10.83MW}{0.65}\right)}{\left[\left(\frac{5MW}{0.3}\right) + \left(\frac{10.83MW}{0.65}\right)\right]} \right\} \times 3356kgCO_2eq = 1678kgCO_2eq$$

Development of efficiency factors for H_1 and P_2 is complicated by the fact that the CHP system incorporates two fuel inputs (F_1 and F_2). 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 F_1) 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 F_2 (E_{F2}), and these total emissions (E_{F2}) are allocated between H_1 and P_2.

There are differing efficiencies associated with converting each of these two energy sources into steam in the HRSG. The mill has information that indicates that the efficiency of the HRSG in converting the heat in the turbine exhaust gas into steam energy is 80%. The efficiency associated with combustion of the 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 as follows:

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

It is assumed that the efficiency associated with H_1 is equivalent to that of producing steam in the HRSG (H_s), 90%. The mill 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 P_2 is:

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

$$E_{F2'} = E_{F2} + E_{Heat} = 2126 + 1678 = 3804kgCO_2eq$$

$$E_{P2} = \left\{ \frac{\left(\frac{3MW}{0.64}\right)}{\left[\left(\frac{3MW}{0.64}\right) + \left(\frac{15MW}{0.9}\right)\right]} \right\} \times 3804kgCO_2eq = 835kgCO_2eq$$

$$E_{H1} = \left\{ \frac{\left(\frac{15MW}{0.9}\right)}{\left[\left(\frac{3MW}{0.64}\right) + \left(\frac{15MW}{0.9}\right)\right]} \right\} \times 3804kgCO_2eq = 2969kgCO_2eq$$

The following table presents a summary of emissions and emission factors for the three outputs in this CHP 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	1678	336
P_2 (Electricity)	3	0.64	N/A	N/A	835	278
H_1 (Steam)	15	0.9	170	7	2969	198
Total					5482	

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:

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

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:

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

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 B1. 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 CO_2 per GJ of total energy) for each energy output are also shown in Table B1.

Table B1. Allocation of GHG Emissions Based on the Heat Content 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. 1 (GJ)	E CO_2 Emissions $E=H\times D_i/\sum D$ (tonne CO_2)	F CO_2 Emission Factor F=E/A (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:

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

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 B2 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 B2. 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 $E=H\times D_i/\sum D$ (tonne CO_2)	F CO_2 Emission Factor F=E/A (tonne CO_2/GJ)
Electricity	245	N/A	N/A	245	48,200	197
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 C

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 by far the most significant component of mobile source emissions. Some of the mobile emissions of interest to pulp and paper mills, 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 2004a). 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 2004d). The WRI/WBCSD calculation tools for transportation emissions are available on the internet (WRI 2004d) and are briefly summarized here as well. The Excel® workbook that accompanies this report incorporates some of the transportation calculation tools from WRI/WBCSD (distance-based calculation tools from WRI/WBCSD are not included in the Excel workbook that accompanies this report).

1.1 Carbon Dioxide

Essentially all protocols suggest that CO_2 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 Emission Inventory Guidebook, third edition (EEA 2004), and the WRI/WBCSD GHG Protocol calculation tools (WRI 2004d). A number of the protocols also give distance-based emission factors (kg CO_2/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.

In some cases, authorities issue a single emission factor shown in CO_2-equivalents that incorporates emissions of CH_4 and N_2O. In the Australian Greenhouse Challenge (AGO 2004), 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 Emissions Inventory Handbook, most recently updated in 1996, and by USEPA. Both sets of emission factors are shown in Tables C1 and C2.

Table C1. Fuel Consumption-Based N_2O and CH_4 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_2O/kg fuel	g N_2O/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 C2. N_2O and CH_4 Emission Factors for Non-Highway Vehicles (IPCC 1997c) (IPCC Revised 1996 Guidelines taken from USEPA)

Source and Engine Type	g N_2O/kg fuel	g N_2O/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 Emission Inventory Guidebook*

The EMEP/CORINAIR Emission Inventory Guidebook contains a second set of emission factors that are based on the power output of the engine (EEA 2004). These emission factors are presented in a way that allows them to be adjusted based on 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 C3.

Table C3. CORINAIR Engine Output-Based N_2O and CH_4 Emission Factors for Non-Road Mobile Sources and Machinery (drawn from EEA 2004)

Source and Engine Type/Size		N_2O (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

1.2.3 *Australia Greenhouse Challenge – Factor and Methods Workbook*

Manufacturers participating in the Australian Greenhouse Challenge estimate emissions using emission factors that include CO_2, CH_4, and N_2O, and also address full fuel cycle emissions (i.e., they include upstream emissions from fuel extraction, processing, and transport) (AGO 2004).

1.2.4 *Finland – Greenhouse Gas Emissions in Finland 1990–2002, National Inventory Report*

The Finnish inventory document, *Greenhouse Gas Emissions in Finland 1990–2002, National Inventory Report*, 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 C4 (Finland Ministry of the Environment 2004).

Table C4. Finnish Emission Factors for Off-road Forestry and Industrial Machinery (Finland Ministry of the Environment 2004)

Source	Fuel	CH_4 (mg/MJ)	N_2O (mg/MJ)
Off-road machinery / Forestry	Gasoil (diesel)	4.3	32.5
Off-road machinery / Forestry	Gasoline	139.0	0.3
Off-road machinery / Construction	Gasoil (diesel)	4.3	31.7
Off-road machinery / Construction	Gasoline	133.4	1.7
Off-road machinery / Other	Gasoil (diesel)	4.1	31.5
Off-road machinery / Other	Gasoline	95.0	1.2
Off-road machinery / Other	LPG	64.6	3.2

1.2.5 *Canada – Canadian GHG Challenge Registry, Guide to Entity & Facility-Based Reporting, Canada’s Climate Change Voluntary Challenge and Registry (VCR) – Version 3.0, July 2004*

The VCR guidance provides a set of emission factors for CO_2, CH_4, and N_2O for use in estimating emissions related to consumption of transportation fuels (VCR 2004). VCR also provides a set of emission factors (in terms of CO_2 equivalents) which can be used to estimate indirect emissions for transportation (e.g., rail transportation, bus travel). VCR-recommended factors are reproduced in Tables C5 and C6.

Table C5. Canadian Emission Factors for Common Transportation Fuels (reproduced from Table 5 of VCR 2004)

Vehicle (fuel)	Carbon Dioxide CO_2	Methane CH_4	Nitrous Oxide N_2O
Car (gasoline)	2.360 kg/l	0.00012 kg/l	0.00026 kg/l
Car (E10 ethanol blend gasoline)	2.124 kg/l	0.00012 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	0.00022 kg/l	0.00041 kg/l
Light truck (E10 Ethanol blend gasoline)	2.124 kg/l	0.00022 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 vehicle (E10 Ethanol blend gasoline)	2.124 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
Motorcycle (E10 Ethanol blend gasoline)	2.124 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 (E10 ethanol blend gasoline)	2.124 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
Boats (gasoline)	2.360 kg/l	0.0013 kg/l	0.00006 kg/l
Ships (diesel)	2.730 kg/l	0.00015 kg/l	0.00100 kg/l
Ships (light “distillate” oil)	2.830 kg/l	0.0003 kg/l	0.00007 kg/l
Ships (heavy “residual” oil)	3.090 kg/l	0.0003 kg/l	0.00008 kg/l
Conventional aircraft (aviation gasoline)	2.330 kg/l	0.00219 kg/l	0.00023 kg/l
Jet aircraft (aviation turbo fuel)	2.550 kg/l	0.00008 kg/l	0.00025 kg/l

Table C6. Canadian Indirect Emission Factors for Transportation (reproduced from Table 6 of VCR 2004)

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)	0.1460 kg CO_2-equiv/passenger-km
Bus travel (inter-city)	0.0565 kg CO_2-equiv/passenger-km
Air travel	0.1359 kg CO_2-equiv/passenger-km

1.2.6 *WRI/WBCSD Greenhouse Gas Protocol and Supporting Documents*

Noting that CH_4 and N_2O emissions “comprise a relatively small proportion of overall transportation emissions,” the WRI/WBCSD Protocol includes only CO_2 emissions from mobile sources. Companies are given the option of estimating CH_4 and N_2O emissions from mobile sources (WRI 2004d). Tables C7 and C8 contain the WRI/WBCSD GHG Protocol default emission factors according to fuel use and distance traveled.

Table C7. Default Emission Factors for Different Transportation Fuels (WRI 2004d)

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
Propane	62.99 (EIA)
Sub-bituminous coal	96.00
Wood, wood residual fuels	100.44 (EIA)
Natural gas	56.06

Table C8. Default Fuel Economy Factors for Different Types of Mobile Sources and Activity Data (WRI 2004d)

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 D

GREENHOUSE GASES FROM WASTE MANAGEMENT AT PULP AND PAPER MILLS: RECOMMENDED APPROACH AND REVIEW OF EXISTING METHODS

1.0 RECOMMENDED APPROACH FOR ESTIMATING CH_4 EMISSIONS FROM LANDFILLS [Note: Much of Section 1.0 is identical to Section 14 in the Calculation Tools Report]

These calculation tools have been developed assuming that many companies will include company-owned landfills within 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 emissions from company-owned landfills will be reported.

As is the case with most widely accepted protocols, only CH_4 emissions are addressed in these tools because the CO_2 from landfills is composed of biomass carbon (not counted as a greenhouse gas) and the N_2O 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 pulp and paper mill 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 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 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 forest products industry landfills because of the limited data for deriving the parameter values needed to use IPCC’s default methodology on forest 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 1998d).

These calculation tools also assume that all of the methane that is captured and burned is converted to biomass CO_2 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.

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

where: REC = *amount of landfill gas collected, determined on a site-specific basis,* m^3/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 pulp and paper 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 CH_4 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).

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

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 1998d).

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

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 them 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, start in year 1 and calculate how much methane will be generated in each subsequent year by waste deposited in that year using Equations 4 and 5.

CH_4 generated in a given year by waste deposited in an earlier year

$$(m^3/y = k\, R_y\, L_0\, (e^{-k[T-Y]}) \qquad \text{(Eq.4)}$$

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.

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

where: CH_4 *generated = from Equation 4*

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

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 forest 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 forest 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 0.09/yr for all landfills (Swedish EPA 2004)

- Canada – k for wood waste landfills equals 0.01/yr, and varies by province for MSW landfills (Environment Canada 2004)

- USEPA – 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 1998d)

- Finland – In its most recent national inventory, Finland used the Tier 2 method of IPCC (Finland Ministry of the Environment 2004). In the 1990–2002 inventory, Finland Ministry of the Environment provides *k* values for different wastes:

  k_1 = 0.2 (food waste in MSW and sludges)
  k_2 = 0.03 (wood waste in MSW and in construction and demolition waste, paper waste containing lignin in MSW)
  k_3 = 0.05 (industrial solid waste and other fractions of MSW than above)

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, or 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 m^3/Mg. An equation is provided for calculating a site-specific L_0 (IPCC 1997c):

  L_0 = (DOC, fraction degradable organic carbon in waste) x (DOC_f , fraction of DOC that degrades into landfill gas) x (16/12, to convert carbon to methane) x (F, fraction CH_4 in gas from a managed landfill, default value is 0.5) x (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 were 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 CH_4/ton of waste specifically for pulp and paper mill sludge landfills. This is equivalent to 63 m^3/Mg (Swedish EPA 2004).

- Finland – Although Finland did not use the first order model approach for landfill methane in earlier national inventories, the approach used still requires estimation of L_0. Finland used the IPCC equation for L_0 and the values presented here 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, as 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 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 CH_4/kg dry waste or 140 to 210 m^3/Mg.

- Canada – To calculate the methane potential for wood waste landfills, Canada uses an L_0 of 118 kg CH_4/ton wood waste, which converts to 165 m^3/Mg. For MSW landfills, Canada has used an L_0 value of 165 kg CH_4/ton for the years 1941 through to 1989. For subsequent years, a value for L_0 of 117 kg CH_4/ton is recommended for MSW landfills (Environment Canada 2004).

- United States – EPA's compilation of emission factors (AP-42) indicates that a value of 100 m^3/Mg is recommended as the default factor for most MSW landfills (USEPA 1998d).

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 m^3/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 D1.

Table D1. Recommended Default Values for k and L_0 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 CH_4 EMISSIONS FROM THE ANAEROBIC TREATMENT OF WASTEWATER OR SLUDGE [Note: Most of Section 2.0 is identical to Section 15 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 CH_4 emissions need to be estimated because (a) the CO_2 emitted from wastewater and sludge treatment operations contains biomass carbon which is not included in most GHG protocols; and (b) other protocols assume that N_2O 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 mill suggest that non-trivial amounts of methane are escaping collection, the mill may need to undertake efforts to account for these releases, but such circumstances are expected to be unusual at mills 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 be estimated only from anaerobic treatment or sludge digestion systems until such time as factors for other types of systems are available.

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

where: OC = *BOD or COD of the feed to the anaerobic system, kg/year*
EF = *emission factor, default values = 0.25 kg* CH_4*/kg COD in the feed or 0.6 kg* CH_4*/kg BOD in the feed (or another BOD-based factor developed by multiplying the COD-based factor of 0.25 kg* CH_4*/kg COD by the site-specific COD/BOD ratio)*
B = *methane captured and burned, kg* CH_4*/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.

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

where: OCs = *organic content of the sludge*
EFs = *emission factor, in units consistent with OCs; IPCC's default value is 0.25 kg* CH_4*/kg COD in the sludge feed*
B = *methane captured and burned, kg* CH_4*/yr, determined on a site-specific basis*

Under most protocols, emissions of N_2O 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 and Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories

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 assumes that all organic matter degrades in the year it is placed in the landfill, while the second 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 D2.

Table D2. 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	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 methane correction factor (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 x 50%) and 20% of the gas from shallow, unmanaged landfills (0.4 x 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 CO_2 released from waste. Hence, these CO_2 emissions are not treated as net emissions from waste in the IPCC Methodology. If biomass raw materials are not being sustainably produced, the net CO_2 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:

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

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* $MCF = 1$*)*

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

where: REC = *amount of methane converted to* CO_2 *by burning*
OX = *fraction of methane converted to* CO_2 *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 CO_2 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 N_2O 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 the studies reported low N_2O emissions. Thus, in IPCC's methodology "N_2O 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 N_2O (IPCC 1997c). In summary, IPCC's guidance contains methods for estimating N_2O released from human sewage once it is discharged, but assumes that N_2O emissions from treatment plants are negligible. There is no discussion of N_2O 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 CH_4 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 CH_4 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:

$$\textit{Methane emissions} = (\textit{TOW or TOS}) \times B_0 \times MCF \qquad (Eq.10)$$

where: TOW or TOS = measure of organic content of anaerobically treated wastewater or sludge
B_0 *=* CH_4 *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 CH_4/kg COD. IPCC's 1996 Revised Guidelines give a default value for B_0 of 0.25 kg CH_4/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 CH_4/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 CH_4/kg COD or a default value of 0.6 kg CH_4/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 – Canadian GHG Challenge Registry Guide to Entity- and Facility-Based Reporting, Canada's Climate Change Voluntary Challenge and Registry and Canada's Greenhouse Gas Inventory 1990-2000

The VCR (2004) guidance does not specifically include emissions from waste management activities. These emissions are included, however, in Canada's Greenhouse Gas Inventory, 1990-2002 (Environment Canada 2004).

Canada does not count CO_2 produced by the decomposition of biomass carbon. Estimates are made for CH_4 and N_2O emissions, however (Environment Canada 2004).

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 2004).

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 (L_0) for wood waste of 118 kg CH_4/tonne of wood waste (Environment Canada 2004).

3.2.2 *Wastewater Treatment and Sludge Digestion*

Canada estimated GHG emissions only from municipal wastewater treatment due to lack of data on treatment of industrial wastewater (Environment Canada 2004).

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 CH_4/person/year could potentially be emitted from wastewater treated anaerobically (Environment Canada 2004). 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 N_2O emissions from human sewage. The IPCC methodology assumes that (a) negligible amounts of N_2O 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 N_2O (Environment Canada 2004).

3.3 Finland – Greenhouse Gas Emissions and Removals in Finland

3.3.1 *Landfills*

The Finnish government's estimates are based on IPCC's all-in-one-year default method (IPCC 1997c) through 2001. The parameter values have been selected to represent conditions in Finland (Technical Research Center of Finland 2001). The parameter values needed to estimate emissions from pulp and paper mill landfills are shown below. The description of the IPCC all-in-one-year approach contains more information on the variables and calculations.

$$\text{Methane released per year} = \\ ([\text{waste disposed per year} \times DOC \times DOC_f \times MCF \times F \times 16/12] - R) - (1 - OX) \qquad \text{(Eq.12)}$$

DOC = weight fraction degradable organic carbon in waste (varies by waste type as shown below; although not specified, the values for DOC strongly suggest that lignin is included)
= 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 because 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 (fraction of degradable organic carbon degraded to landfill gas; IPCC's 1996 Revised Guidelines suggest a default of 0.77, but the May 2000 Good Practices document revised this default value to 0.5 to 0.6 for* DOC_f *in cases where the lignin is included in the DOC; Finland uses 0.5 to reflect the low temperature and less-than-optimal conditions for decomposition in Finnish landfills)*

MCF = 0.7 (essentially the landfill's methane generation potential relative to a "managed" landfill; Finland 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 (fraction of landfill gas that is methane; IPCC default assumes that landfill gas is 50% methane)

16/12 = factor to convert from carbon to methane

R = amount of landfill methane recovered; value varies from year to year

OX = 0.1 (10% of methane that is not recovered is oxidized to CO_2 in the upper layers of the landfill cover)

In its most recent national inventory, Finland used the Tier 2 method of IPCC (Finland Ministry of the Environment 2004). In the 1990-2002 inventory, Finland Ministry of the Environment provided *k* values for different wastes:

k_1 = 0.2 (food waste in MSW and sludges)
k_2 = 0.03 (wood waste in MSW and in construction and demolition waste, paper waste containing lignin in MSW)
k_3 = 0.05 (industrial solid waste and other fractions of MSW than above)

3.3.2 *Wastewater Treatment and Sludge Digestion*

Finland uses IPCC's default methodology to estimate methane emissions from wastewater treatment (Finland Ministry of the Environment 2004).

$$\text{Emissions of } CH_4 = \text{Organic load} \times B_0 \times MCF \qquad \text{(Eq. 13)}$$

where: Organic load is expressed (in Finland's case) as COD in industrial wastewaters and BOD in domestic wastewaters.
B_0 = the maximum methane generation potential – Finland uses the default value given in the IPCC 1996 Revised Guidelines of 0.25 kg CH_4/kg COD or BOD. IPCC's May 2000 Good Practices document revised the default value to 0.25 kg CH_4/kg COD and 0.6 kg CH_4/kg BOD.
MCF = a weighted average value reflecting the methane generation potential of the treatment plants in Finland relative to an anaerobic treatment plant. Finland used an MCF of 0.01 for domestic wastewaters, and 0.005 for industrial wastewaters.

Emissions of N_2O are estimated according to IPCC's Revised 1996 Guidelines, except that Finland expands the scope to include nitrogen discharged not only in domestic sewage, but in industrial wastewaters and fish farm wastes (Finland Ministry of the Environment 2004). The IPCC method estimates the N_2O released from wastewater once it is discharged, but assumes that N_2O emissions from the treatment plants are negligible.

3.4 Japan – Information from the Japan Paper Association

3.4.1 *Landfills*

In preparing national inventories for greenhouse gases, the Ministry of Environment includes methane and nitrous oxide from landfills containing "paper waste," assumed to be sludges and other process wastes from pulp and paper manufacturing (JPA 2001). The emission factors are:

Methane = 151 kg/ton paper waste
Nitrous Oxide = 0.01 kg/ton paper waste

3.5 Sweden – Sweden's National Inventory Report 2004

3.5.1 *Landfills*

In *Sweden's National Inventory Report 2004*, Sweden used an approach very similar to IPCC's first order decay approach to estimate methane emissions from landfills. Waste landfilled in 1952 and after is included in the analysis. The time factor in the rate equation is adjusted slightly to correspond to an assumption that all waste is landfilled on July 1 of each year. In addition, Sweden has developed country-specific values for a number of the parameters used in the model (Swedish EPA 2004).

The Swedish government has examined methane generation from pulp mill sludge landfills. It uses a value of 45 kg CH_4/ton of waste to represent the methane generation potential for landfilled pulp mill sludge (Swedish EPA 2004).

The other values used in the first order model for methane emissions from landfills are as follows (Swedish EPA 2004):
MCF before 1980 = 0.6
MCF in 1980 and after = 1.0
F (fraction of methane in landfill gas) = 0.5
DOC_f (fraction of degradable organic carbon degraded to landfill gas) = 0.7
OX (fraction of non-collected gas oxidized in surface layers of the landfill) = 0.1
$t_{1/2}$ (half-life of the methanogenesis) = 7.5 years
k (first order rate constant assuming a half-life of 7.5 years) = 0.092/yr

3.5.2 *Wastewater Treatment and Sludge Digestion*

The Swedish National Inventory Report indicates that "[n]ational activity data on nitrogen in discharged wastewater is used, in combination with a model estimating nitrogen in human sewage from people not connected to municipal waste water treatment plants" (Swedish EPA 2004). The formula used to estimate nitrous oxide emissions from nitrogen in discharged wastewater includes terms for data associated with municipal wastewater treatment plants, industrial treatment plants, and small treatment plants for which data were not available (this last term incorporates assumptions associated with the number of people connected to small treatment plants and nitrogen consumption by these people). The IPCC default factor for conversion of nitrogen to nitrous oxide is used.

Sludge-related emissions of methane from landfills were estimated as explained above. GHG emissions from anaerobic sludge digestion were not discussed, although the report noted that the landfill gas potential of already digested sludge was reduced by 50% (Swedish EPA 2004).

3.6 United States – EPA Inventory of US Greenhouse Gas Emissions and Sinks: 1990-2002 and Anthropogenic Methane Emissions in the United States: Estimates for 1990, Report to Congress

3.6.1 *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: 1990-2002* (USEPA 2004, p. 231):

> Methane emissions from landfills were estimated to equal the CH_4 produced from municipal landfills, minus the CH_4 recovered and combusted, plus the CH_4 produced by industrial landfills, minus the CH_4 oxidized before being released into the atmosphere.
>
> The methodology for estimating CH_4 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, as evidenced in an extensive landfill survey by the EPA's Office of Solid Waste in 1986. 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 CH_4 generation was estimated using its year of opening, its waste acceptance rate, year of closure, and design capacity. Data on national municipal waste landfilled 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 of landfill gas-to-energy (LFGTE) projects compiled by EPA's Landfill Methane Outreach Program (LMOP)….
>
> Emissions from industrial landfills were assumed to be equal to seven percent of the total CH_4 emissions from municipal landfills. The amount of CH_4 oxidized by the landfill cover at both municipal and industrial landfills was assumed to be ten percent of the CH_4 generated that is not recovered. To calculate net CH_4 emissions, both CH_4 recovered and CH_4 oxidized were subtracted from CH_4 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 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 1998d). 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 m^3 methane/Mg waste is recommended (USEPA 1998d). 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).

3.6.2 *Wastewater Treatment and Anaerobic Sludge Digestion*

In prior inventories (e.g., that discussed in USEPA 2001a) EPA indicated 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. In these prior inventories 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).

In its most recent inventory EPA estimated industry wastewater treatment emissions using a different methodology. The following description of that methodology is taken from EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2002* (USEPA 2004, page 235), and is stated by EPA to be consistent with the methodology described by IPCC (2000):

> Methane emissions… were estimated by multiplying the annual product output (metric tons/year) by the average outflow (m^3/ton of output), the organics loading in the outflow (grams of organic COD/m^3), the emission factor (grams CH_4/grams COD), and the percentage of organic COD assumed to degrade anaerobically. In developing estimates for the pulp and paper category, BOD was used instead of COD, because more accurate BOD numbers were available. The emission factor used for pulp and paper wastewater was 0.6 kg CH_4/kg BOD_5… (here EPA cites IPCC 2000).
>
> Wastewater treatment for the pulp and paper industry typically includes neutralization, screening, sedimentation, and flotation/hydrocycloning to remove solids. The most important step is lagooning for storage, settling, and biological

> treatment (secondary treatment). In determining the percent that degraded anaerobically, both primary and secondary treatment were considered. Primary treatment lagoons are aerated to reduce anaerobic activity. However, the lagoons are large and zones of anaerobic activity may occur. Approximately 42 percent of the BOD passes on to secondary treatment, which are less likely to be aerated (EPA 1993). It was assumed that 25 percent of the BOD in secondary treatment lagoons degrades anaerobically, while 10 percent passes through to be discharged with the effluent (here EPA cites the 1997 publication EPA-600/R-97-091). Overall, the percentage of wastewater organics that degrade anaerobically was determined to be 10.3 percent…

There are potentially significant differences between the IPCC (2000) guidance cited by EPA and the methodology developed by EPA from that guidance. The IPCC guidance recommends multiplying the quantity of organic material in the effluent by the "maximum methane producing capacity" (0.6 lb CH_4 per lb BOD) and then by the "fraction of waste *treated anaerobically*" [emphasis added], whereas the EPA methodology is to multiply the quantity of organic material by the "emission factor" (0.6 lb CH_4 per lb BOD) and then by the "percentage of organic [BOD] *assumed to degrade anaerobically*" [emphasis added]. From this assessment it is clear that where the IPCC recognizes a potential for methane formation from anaerobic decomposition of organic matter, EPA assigns an emission factor that is equivalent to this maximum potential. Furthermore, where IPCC recommends assessing the fraction of waste that is actually treated anaerobically, EPA assumes an amount of organic material in the waste stream that is degraded anaerobically, regardless of the waste treatment technology applied.

3.7 WRI/WBCSD – The Greenhouse Gas Protocol, October 2001

The WRI/WBCSD Protocol (WRI 2001, 2004a) 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 E

CARBON DIOXIDE FROM BIOMASS COMBUSTION

1.0 ESTIMATES OF CO_2 EMISSIONS FROM BIOMASS COMBUSTION

Pulp and paper mills generate approximately two thirds of their energy needs from biomass fuels recovered from the industry's waste and process streams. Energy-rich biomass–derived from wood chips, bark, sawdust, and pulping liquors 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 CO_2 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 CO_2 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).

1.1 Estimated Biomass Emissions

The information on biomass emissions reported herein 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, and
- To provide awareness and understanding of how biomass fuels are generated and used in the manufacture of pulp and paper.

Tables E1 through E3 can be used to estimate emissions of CO_2 from biomass combustion and Table E4 can be used to 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 2001, 2004a). Users of these calculation tools may elect to modify the format and type of information presented based on specific facility or company needs.

Table E1. Estimating Emissions of Biomass-Derived CO_2 from Combustion of Wood, Bark, and other Biomass Fuels (except pulping liquors, which are addressed in Table E2)

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 LHVs.]	CO_2 emission factor: [default value is: solid biomass: 109* kg CO_2/GJ LHV]	Unit of CO_2 emission factor	CO_2 emissions in kg CO_2/yr	CO_2 emissions in metric tons Carbon/yr
						E = A * C	F = E*12/44 / 1000
Example: Bark Boiler	Bark	500,000	GJ (LHV)	109	kg CO_2 / GJ LHV	54,500,000	14,900
Biomass Carbon Released as CO_2 from Combustion of Wood , Bark, or other biomass (except pulping liquors which are addressed in Table 2 below)							
Amount of biomass-derived CO_2 included in above number that is exported (e.g., to PCC plant) rather than being emitted - Optional information							

* Emission factor for solid biomass from Intergovernmental Panel on Climate Change (IPCC). 1997. *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual (Volume 3)*. Table 1.1, corrected for 1% unburned carbon (USEPA 2001b)

NOTE: All listed emission factors are based on LHV, assumed to be 95% of HHV for biomass fuels

Table E2. Estimating Emissions of Biomass-Derived CO_2 from Pulping Liquors and Kraft Mill Lime Recovery

Note that because the emission factors for spent pulping liquors are based on the carbon content of the liquors (assuming a one-percent correction for unoxidized carbon), the liquor emission factor will include any carbon exiting with smelt from a recovery furnace. Therefore, for kraft mills, the liquor emission factors estimate biomass carbon emissions from both the recovery furnace and from the lime kiln.

Companies have the option of estimating the amounts of biomass-derived CO_2 that is exported rather than being returned to the atmosphere. If the exports are from a lime kiln or calciner where fossil fuels are being used, as a general approximation the exports of biomass-derived CO_2 will be twice the exports of fossil fuel-derived CO_2 (see "CO_2 Imports and Exports" worksheet). Where exports consist of gases from a lime kiln or calciner that is burning only biomass fuels, all of the exports are biomass-derived CO_2.

		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 LHVs.]	CO_2 emission factors: [default values are listed in Table E3 below; kg CO_2/GJ LHV]	Unit of CO_2 emission factor	CO_2 emissions in kg CO_2/yr	CO_2 emissions in metric tons Carbon/yr
Source Description	Fuel Type					E = A * C	F = E*12/44 / 1000
Example: Recovery Furnace	Kraft Pulping Liquor, North American SW	100,000	GJ (LHV)	94.2	kg CO_2 / GJ LHV	9,420,000	2,570
Biomass carbon in pulping liquors released as CO_2 from the recovery furnace and lime kiln or calciner							
Amount of biomass-derived CO_2 included in above number that is exported (e.g., to PCC plant) rather than being emitted - optional information							

NOTE: All listed emission factors are based on LHV, assumed to be 95% of HHV for biomass fuels

Table E3. Suggested Pulping Liquor Default Emission Factors for Biomass-Derived CO_2
(includes emissions from both the recovery furnace and lime kiln/calciner)

Type of Pulping Liquor	Wood Furnish	Typical Carbon Content [percent, dry basis]	Typical Energy Content – HHV [GJ HHV / metric ton dry solids]	Calculated Energy Content - LHV [GJ LHV / metric ton dry solids]	Biomass-Derived CO_2 Emission Factor [kg CO_2 / GJ LHV]
Kraft black liquor*	Scandinavian Softwood	35	14.2	13.5	94.2
Kraft black liquor*	Scandinavian Hardwood	32.5	13.5	12.8	92.0
Kraft black liquor*	North American Softwood	35	14.2	13.5	94.2
Kraft black liquor*	North American Hardwood	34	13.9	13.2	93.5
Kraft black liquor*	Tropical Eucalyptus	34.8			
Kraft black liquor*	Tropical Mixed Woods	35.2	14.1	13.4	95.4
Kraft black liquor*	Bagasse	36.9	14.8	14.1	95.3
Kraft black liquor*	Bamboo	34.5	14.1	13.4	93.5
Kraft black liquor*	Straw	36.5	14.7	14.0	94.9
Semi-Chemical					to be determined
Sulfite					to be determined

* Kraft black liquor default emission factors are based on the carbon content of the liquors (assuming a one-percent correction for unoxidized carbon) and include any carbon exiting with smelt from a recovery furnace. Therefore, for kraft mills, the liquor emission factors estimate biomass carbon emissions from both the recovery furnace and from the lime kiln. Factors obtained from: Chapter 1- Chemical Recovery, by Esa Vakkilainen. 1999. In: *Papermaking Science and Technology, Book 6B: Chemical Pulping*. Gullichsen, J., and Paulapuro, H. (eds.). Helsinki, Finland: Fapet Oy

Table E4. Emissions of Biomass-Derived CO_2

Write "NA" to show an item is not applicable. *Where emissions have been determined to be insignificant or non-material, write "NM" and explain the basis for the determination in a footnote.*		Emissions of Biomass-Derived CO_2 (metric tones)
1	Biomass-fueled boilers (from Table E1 in Annex E)	
2	Pulping liquor-derived CO_2 (from Table E2 in Annex E)	
3	Total Emissions of Biomass-Derived CO_2 (Sum of line 1 and 2)	
Explain the method used to determine ownership of emissions from sources not completely owned by the company. Use the WRI/WBCSD GHG Protocol for guidance on determining ownership. Include any other information that is needed to understand the inventory results:		

ANNEX F

TABLES OF GREENHOUSE GAS 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 CO_2 Emission Factors for Fossil Fuels (after IPCC 1997b)

Fossil Fuel	Uncorrected Emission Factor kg CO_2/TJ*	Corrected Emission Factor kg CO_2/TJ
Crude oil	73,300	72,600
Gasoline	69,300	68,600
Kerosene	71,900	71,200
Diesel oil	74,100	73,400
Residual fuel oil	77,400	76,600
LPG	63,100	62,500
Petroleum coke	100,800	99,800
Anthracite coal	98,300	96,300
Bituminous coal	94,600	92,700
Sub-bituminous coal	96,100	94,200
Lignite	101,200	99,200
Peat	106,000	104,900
Natural gas	56,100	55,900

* 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.

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 (2004)*	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 (2004) do not specify correction factors for unoxidized carbon, however all emission factors presented in VCR (2004) are drawn from Environment Canada 2004

Table 4. IPCC Tier 1 CH_4 and N_2O Emission Factors for Stationary Combustion (from IPCC 1997c)

	CH_4 Emission Factors kg/TJ	N_2O Emission Factors kg/TJ
Coal	10	1.4
Natural gas	5	0.1
Oil	2	0.6
Wood/wood residuals	30	4

Table 5. IPCC Tier 2 Uncontrolled CH_4 and N_2O Emission Factors for Industrial Boilers (IPCC 1997c)

Fuel	Technology	Configuration	kg CH_4/TJ	kg N_2O/TJ
Bituminous coal	Overfeed stoker boilers		1.0	1.6
Sub-bituminous coal	Overfeed stoker boilers		1.0	1.6
Bituminous coal	Underfeed stoker boilers		14	1.6
Sub-bituminous coal	Underfeed stoker boilers		14	1.6
Bituminous coal	Pulverized	Dry bottom, wall fired	0.7	1.6
Bituminous coal	Pulverized	Dry bottom, tang. fired	0.7	0.5
Bituminous coal	Pulverized	Wet bottom	0.9	1.6
Bituminous coal	Spreader Stoker		1.0	1.6
Bituminous coal	Fluidized bed	Circulating or bubbling	1.0	96
Sub-bituminous coal	Fluidized bed	Circulating or bubbling	1.0	96
Anthracite			10*	1.4*
Residual oil			3.0	0.3
Distillate oil			0.2	0.4
Natural gas	Boilers		1.4	0.1*
Natural gas	Turbines		0.6	0.1*
Natural gas	Int. comb. engine	2-cycle lean burn	17	0.1*
Natural gas	Int. comb. engine	4-cycle lean burn	13	0.1*
Natural gas	Int. comb. engine	4-cycle rich burn	2.9	0.1*

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

Table 6. Emission Factors for Kraft Mill Lime Kilns and Calciners

	Emissions, kg/TJ					
Fuel	Kraft mill lime kilns			Kraft mill calciners		
	CO_2	CH_4	N_2O	CO_2	CH_4	N_2O
Residual oil	76,600*	2.7[θ]	0[χ]	76,600*	2.7[θ]	0.3[ϕ]
Distillate oil	73,400*	2.7[θ]	0[χ]	73,400*	2.7[θ]	0.4[ϕ]
Natural gas	55,900*	2.7[θ]	0[χ]	55,900*	2.7[θ]	0.1[ϕ]
Biogas	0	2.7[θ]	0[χ]	0	2.7[θ]	0.1[δ]

* from Table 2, corrected for unburned carbon

[θ] from NCASI 1980

[χ] based on IPCC description of temperatures giving rise to N_2O emissions

[ϕ] from Table 5

[δ] assumed appropriate to use the emission factor for natural gas, as the composition and combustion conditions for biogas are more similar to natural gas than to other fuels

Table 7. Emissions from Calcium- and Sodium-Carbonate Make-up in the Pulp Mill*

	Emissions
Pulp mill make-up $CaCO_3$	440 kg CO_2/ t $CaCO_3$
Pulp mill make-up Na_2CO_3	415 kg CO_2/ t Na_2CO_3

* if carbonate is derived from biomass, GHG emissions are zero

Table 8. Emission Factors for CH_4 and N_2O from Biomass Combustion

Emission Factor Description	kg CH_4/TJ	kg N_2O/TJ	Reference
Wood waste-fired boilers			
Wood, wood waste, and other biomass and wastes	30	4	Tier 1 – IPCC 1997c
Uncontrolled emissions from wood-fired stoker boilers	15	-	Tier 2 – IPCC 1997c
Average for wood residue combustion	9.5*	5.9*	USEPA 2001
Average for circulating fluidized bed boilers burning peat or bark	1	8.8	Fortum 2001
Average for bubbling fluidized bed boilers burning peat or bark	2**	<2	Fortum 2001
Pre-1980 wood residue-fired stoker boilers sampled ahead of control devices	8.2*	-	NCASI 1980
Pre-1980 wood residue-fired stoker boilers sampled after wet scrubbers	2.7*	-	NCASI 1985
Wood fired boiler	41^{λ}	3.1^{λ}	JPA 2002
Wood as fuel	24^{λ}	3.4^{λ}	AEA Tech. 2001
Wood waste	30	5	Swedish EPA 2004
Median emission factors for wood waste	***12***	***4***	
	1 – 40	1.4 – 75	EEA 2004
Recovery furnaces			
Recovery furnace	<1	<1	Fortum 2001
Recovery furnace – black liquor	2.5^{Ω}	-	JPA 2002
Black Liquor	30	5	Swedish EPA 2004
Median emission factors for black liquor	***2.5***	***2***	
	1 –17.7	1 – 21.4	EEA 2004

* converted from GCV to NCV assuming a 5% difference

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

$^{\lambda}$ based on heat content of 20 GJ/t dry solids

$^{\Omega}$ based on liquor heat content of 13.3 GJ/t dry solids

Table 9. Emission Factors for Non-Road Mobile Sources and Machinery (IPCC 1997c) (IPCC Revised 1996 Guidelines taken from EMEP/CORINAIR)

Source and Engine Type	CO_2 kg/TJ	CH_4 kg/TJ	N_2O kg/TJ	CO_2-equiv. kg/TJ
Forestry – diesel	73,400*	4	30	82,800
Industry – diesel	73,400*	4	30	82,800
Railways – diesel	73,400*	4	30	82,800
Inland waterway – diesel	73,400*	4	30	82,800
Marine – diesel	73,400*	7	2	74,200
Industry – gasoline 4-stroke	68,600*	50	2	70,300
Forestry – gasoline 2-stroke	68,600*	170	0.4	72,300
Industry – gasoline 2-stroke	68,600*	130	0.4	71,500
Inland waterway – gasoline 4-stroke	68,600*	40	2	70,100
Inland waterway – gasoline 2-stroke	68,600*	110	0.4	71,000

* from Table 2, corrected for unburned carbon

ANNEX G

SUMMARY OF SIGNIFICANT REVISIONS TO VERSION 1.0

This report, *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills, Version 1.1*, is the first major revision of the original version of the report which was published in late 2001. The revision was undertaken for several reasons:

- Correct minor errors in the original version
- Reflect new guidance provided in the March 2004 Revised Edition of the *GHG Protocol* (WRI 2004a)
- Reflect new guidance contained in national guidance documents

This annex provides a summary of the significant changes made to the report. Changes in the wording and organization of the report, made solely to enhance clarity, will not be reflected in this annex. Only material changes are included herein.

Executive Summary

The wording was modified to help clarify the difference between organizational boundaries and operational boundaries.

Section 1

The *Climate Leaders Greenhouse Gas Inventory Protocol Core Module Guidance* issued by the United States Environmental Protection Agency (USEPA) and the *Canadian GHG Challenge Registry, Guide to Entity & Facility-Based Reporting* issued by the Voluntary Challenge and Registry (VCR) were added as examples of “accepted GHG protocols” that the pulp and paper tools are intended to be used with. These two protocols were also identified in Section 3.

The GHG protocol developed by Georgia-Pacific Corporation is referred to as an example of how one company developed a protocol specific to the forest products industry (GP 2002).

Section 3

The *Tool for Calculating HFC and PFC Emissions from the Manufacturing, Installation, Operation and Disposal of Refrigeration and Air-conditioning Equipment, Version 1.0*, currently being developed by WRI/WBCSD, was identified as a resource for companies wishing to estimate emissions of these GHGs.

The wording was modified to help clarify the difference between organizational boundaries and operational boundaries.

Section 4

The discussion on determining objectives of a GHG inventory was abbreviated.

The section on identifying boundary conditions of the inventory was revised to reflect changes in the March 2004 GHG Protocol (WRI 2004a). The reader is referred to the GHG Protocol for additional information on determining organizational boundaries.

Subsection 4.3.2 was expanded to provide more information on the differences between fuel energy in terms of GCV (HHV) and NCV (LHV), including an estimate of the relationship between GCV and NCV for biomass fuels.

The term “climate neutral” no longer appears in the report because it is inaccurate; i.e., methane and nitrous oxide emissions from biomass combustion must be included in GHG inventory totals. A short section on biomass fuels was added explaining why biomass-derived CO_2 emissions are often called “carbon neutral.” Throughout the rest of the report, however, the terms “biomass,” “biomass fuels,” or “biomass carbon” are used instead of “carbon neutral.”

Sections 5 and 6

These sections are in the reverse order of the original report and the discussion has been modified extensively to help clarify organizational and operational boundary issues.

Section 7

The discussion of materiality and insignificant emissions was revised to reflect the guidance in the March 2004 GHG Protocol (WRI 2004a).

Section 8

A discussion of differing purposes of inventories that can influence the required level of resolution of emission estimates was included, as well as discussion of source-specific versus facility-specific activity data in developing an inventory.

A discussion of variability of emission factors for coal and for differing grades of natural gas was added.

The discussion on corrections to emission factors to account for unoxidized carbon was expanded. A table of IPCC recommended corrections (Table 3) was added.

A discussion of methane emissions from some natural gas-fired combustion devices that may be higher than those indicated by published emission factors was added, including how source emission testing results can be used to estimate emissions from these sources.

A discussion of the appropriate use of Tier 1 versus Tier 2 emission factors for estimating methane and nitrous oxide emissions was added, as well as a table of the IPCC Tier 1 emission factors for methane and nitrous oxide (Table 4).

The discussion on estimating methane and nitrous oxide emissions from combination fuel fired boilers burning biomass and fossil fuels was revised and expanded.

A summary of guidance for estimating methane and nitrous oxide emissions from stationary combustion sources was added.

The example calculation for estimating emissions from natural gas consumption was revised to clearly indicate that the calculation is based on facility-specific activity (fuel consumption) data combined with Tier 1 emission factors for methane and nitrous oxide.

The example calculation "CO_2, CH_4, and N_2O emissions from natural gas use at a small mill" was modified by changing the natural gas density parameter from 0.8 kg/m^3 to 0.673 kg/m^3. An math error was also corrected in this example calculation.

Section 9

The footnotes for Table 6 (emission factors for kraft mill lime kilns and calciners) were revised.

Section 10

Information on CO_2 emissions from make-up carbonate consumption was assigned a subsection number (10.1)

A new subsection (10.2) was added which discusses CO_2 emissions from limestone and dolomite consumption in flue gas desulfurization (FGD) systems.

Slight wording changes have been made in this section and elsewhere in the report to clarify that only imported electricity, steam, or heated/chilled water that is "consumed" by the company must be included in calculations of indirect emissions. If the imported energy is merely transmitted to another company, it has not been "consumed" and is not associated with indirect emissions.

Section 11

The discussion on reporting biomass combustion CO_2 emissions was revised to reflect that the March 2004 GHG Protocol (WRI 2004a) no longer refers to the reporting of these emissions as "supporting information."

A discussion on emissions from the combustion of non-condensable gases (NCGs) from the kraft pulping process was included.

A discussion about why it may be most appropriate to use the IPCC Tier 1 emission factors for wood-fired combustion equipment other than boilers, rather than those developed for industrial boilers, was added.

The discussion on estimating emissions from combination fuel-fired boilers burning biomass and fossil fuels was revised and expanded.

Section 12

The discussion on accounting for transmission and distribution losses associated with imported/purchased electricity was expanded to reflect guidance in the March 2004 GHG Protocol (WRI 2004a).

The subsection that discussed netting imports and exports of electricity/steam was deleted (the statement “[c]ompanies wanting to conform to the WRI/WBCSD GHG Protocol should not net imports and exports or associated emissions” is still included).

An error in the example calculation for allocating emissions from CHP systems using the simplified efficiency method was corrected (error was typographical in nature).

Wording was added clarifying that emissions associated with exported power, steam, or heated/cooled water are a subset of company direct emissions and must be included in direct emissions totals.

Section 13

The subsection providing guidance on estimating on-road transportation emissions based on distance traveled (rather than based on fuel consumption) was deleted. The table of distance-based emission factors was also deleted (this information remains available in Annex C).

A discussion of the variety of parameters which can affect CH_4 and N_2O emissions from transportation vehicles was added.

A discussion of the less accurate emission estimates resulting from distance-based activity data as opposed to estimates from fuel consumption-based data (and associated emission factors) was added.

Section 14

A discussion on estimating methane emissions from unmanaged piles of wood residuals was added.

Guidance that companies should adjust the amounts of material landfilled to account for inert wastes (e.g., boiler ash, concrete, etc.), if the required data are available, when estimating methane emissions from landfills was added.

Section 15

Text was added explaining that CO_2 resulting from biomass-derived methane combustion is not included in GHG inventory totals but, under the GHG Protocol, it must be included as additional information. It is also noted that CO_2 generated by aerobic wastewater treatment systems is generally not reported at all because it is not combustion related.

Section 16

The example table for reporting direct emissions (Table 12) was revised to include a place to report additional information associated with the portion of direct emissions that are attributable to exports of energy (these are a subset of total direct emissions, and are not to be subtracted from total direct emissions in the example reporting format). In addition, "0.0" was replaced by "N/A" in the cells for reporting CO_2 emissions from biomass combustion, landfill emissions, and anaerobic wastewater treatment plant emissions. Corresponding revisions were made to Table 16.

The example table for reporting indirect emissions (Table 13) was revised to delete the option of reporting direct emissions associated with exports of energy. Corresponding revisions were made to Table 17.

In the example table for reporting emission factors (Table 14), "0.0" was replaced by "N/A" in the cells for reporting CO_2 emission factors for biomass fuel combustion. Corresponding revisions were made to Table 18.

Reference Section

The reference section was updated to delete literature citations which were no longer cited in the body of the report. All internet addresses were updated where necessary. New citations were added where necessary.

Annexes

Annex A (GHG emissions from stationary fossil fuel combustion – overview of methods in existing protocols) was removed.

Annex C (CH_4 and N_2O emissions from biomass combustion – overview of methods in existing protocols) was removed.

Annex D (GHG emissions attributable to imports and exports of power and steam – overview of methods in existing protocols) was removed.

Annex H (Allocating GHG emissions from partly owned or partly controlled sources – overview of methods in existing protocols) was removed.

A new annex containing reproductions of the tables of emission factors contained in the body of the report was added.

A new annex presenting a summary of significant revisions to version 1.0 of the tool was added.

All remaining annexes were updated to reflect the current guidance from various national and international protocols.

The biomass combustion CO_2 emission factors for spent pulping liquors, presented in Annex E (Table E3), were corrected to eliminate an approximate 5% error (error was introduced when incorrectly converting mass of carbon to corresponding mass of carbon dioxide). The footnote to Table E3 was modified. This correction necessitated modifying the example calculation in Table E2.

ANNEX H

REFERENCES FOR ANNEXES A THROUGH G

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