

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

Version 1.0

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
American Forest and Paper Association

Prepared by
NCASI, Research Triangle Park, NC, USA

Questions or comments on this material can be directed to
Reid Miner
NCASI
P.O. Box 13318
Research Triangle Park, NC, USA 27709-3318
phone + 919-558-1991
fax +919-558-1998
e-mail rminer@ncasi.org

CALCULATION TOOLS FOR ESTIMATING GREENHOUSE GAS EMISSIONS FROM PULP AND PAPER MILLS

EXECUTIVE SUMMARY

In early 2001, a group of pulp and paper industry associations from around the globe (the International Council of Forest and Paper Associations) decided to jointly support a project to develop international tools for estimating greenhouse gas (GHG) emissions from pulp and paper mills. The group retained the National Council for Air and Stream Improvement, Inc. (NCASI) to review existing greenhouse gas inventory protocols and to develop calculation tools to assist companies in preparing GHG inventories. The results of the review and the calculation tools are contained in this report. It is intended that these industry-specific tools 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) or other accepted protocols 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 protocols issued by the Intergovernmental Panel on Climate Change (IPCC) and the WRI/WBCSD.

These tools estimate CO₂ emissions from fossil fuel combustion based on the carbon content of the fuel (or a comparable emission factor) and the amount burned. Carbon dioxide emissions from biomass combustion are not counted as greenhouse gas emissions, a convention common to most of the protocols examined in this review, but can be reported as “supporting information” as called for in the WRI/WBCSD GHG Protocol. Methane and nitrous oxide emissions from combustion processes, both fossil fuel and biomass, are estimated using emission factors. Methods are presented for estimating the fossil-CO₂, methane, and nitrous oxide emissions from lime kilns and calciners. Greenhouse gas emissions from mill 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 and emissions attributable to exports of electricity or steam are included in the inventory results but tracked separately from direct emissions. The emissions from combined heat and power (CHP) plants are allocated using the WRI/WBCSD “efficiency method.”

The calculation tools envision that companies will often construct inventory boundaries that include emissions from (a) all on-site “core” pulp and paper making operations, regardless of the ownership of the emission source; and (b) other company-owned sources included in widely accepted GHG inventory protocols (e.g., company-owned truck fleets). It is understood, however, that companies will select inventory boundaries 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.

To aid in interpreting the results of the inventory, these tools recommend that the inventory results include a list of the operations contained within the boundaries of the inventory and a list of emission factors used to estimate emissions. The format suggested for presenting the results of the inventory allows a company to separate the emissions that are “owned” by the company (direct emissions) from those that are not (indirect emissions). The company is free to select the method for determining the ownership of emissions, but the method must 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.

Acknowledgements

This document (and the Excel[®] file that accompanies it) have undergone a peer review which was organized by WRI/WBCSD. NCASI and ICFPA acknowledge the contributions of the peer review participants:

- Adam Costanza, International Paper Company
- Chris Laughran and Terry Shires, URS Corporation, on behalf of Karen Ritter and the American Petroleum Institute GHG Emissions Methodology Workgroup
- Inna Gritsevich, Center for Energy Efficiency (CENef) in Russia

The assistance from members of the ICFPA Climate Change Working Group and Technical Experts Working Group are also gratefully acknowledged.

CONTENTS

1.0	INTRODUCTION	1
2.0	FOREST PRODUCTS INDUSTRY GREENHOUSE GAS EMISSIONS IN PERSPECTIVE.....	2
3.0	RELATIONSHIP OF THESE CALCULATION TOOLS TO OTHER GREENHOUSE GAS PROTOCOLS.....	2
4.0	OVERVIEW OF THE CALCULATION TOOLS	4
4.1	Purpose of the Calculation Tools.....	4
4.2	Steps Involved in Applying the Calculation Tools	4
4.3	Data Quality	6
4.4	Units.....	7
5.0	IDENTIFYING CORE PULP AND PAPER OPERATIONS TO BE INCLUDED WITHIN THE OPERATIONAL BOUNDARIES OF THE INVENTORY	8
6.0	DETERMINING THE ORGANIZATIONAL BOUNDARIES OF THE INVENTORY AND OWNERSHIP OF EMISSIONS	10
7.0	MATERIALITY AND INSIGNIFICANT EMISSIONS	11
8.0	GREENHOUSE GAS EMISSIONS FROM STATIONARY FOSSIL FUEL COMBUSTION	13
8.1	Carbon Dioxide.....	13
8.2	Methane and Nitrous Oxide.....	14
9.0	EMISSIONS FROM KRAFT MILL LIME KILNS AND CALCINERS.....	19
10.0	CARBON DIOXIDE EMISSIONS FROM MAKE-UP CHEMICALS	22
11.0	EMISSIONS FROM STATIONARY COMBUSTION OF BIOMASS FUELS	23
11.1	Climate-Neutral Carbon Dioxide Emissions from Burning Biomass Fuels	23
11.2	Methane and Nitrous Oxide Emissions from Burning Biomass Fuels	24
12.0	EMISSIONS ATTRIBUTABLE TO IMPORTS AND EXPORTS OF ELECTRICITY AND STEAM.....	26
12.1	Emission Factors for Purchased Power and Steam.....	26

12.2	Netting Imports and Exports	27
12.3	Electricity Imports	27
12.4	Electricity Exports	28
12.5	Steam Imports	29
12.6	Steam and Hot Water Exports.....	29
12.7	Allocating Emissions from Combined Heat and Power (CHP) Systems	29
13.0	GREENHOUSE GAS EMISSIONS FROM VEHICLES AND MISCELLANEOUS FOSSIL FUEL-FIRED EQUIPMENT	33
13.1	Greenhouse Gases from On-Road Vehicles	33
13.2	Greenhouse Gases from Off-Road Vehicles and Equipment	33
14.0	GREENHOUSE GAS EMISSIONS FROM MILL WASTE IN LANDFILLS	36
14.1	Using Data from Landfill Gas Collection Systems.....	37
14.2	Estimating Landfill Methane Emissions at Mill Landfills without Gas Collection Data	38
15.0	GREENHOUSE GAS EMISSIONS FROM ANAEROBIC TREATMENT OF WASTEWATER OR SLUDGE	42
15.1	Anaerobic Treatment Operations where Off-Gases are Captured	42
15.2	Anaerobic Treatment Operations where Off-Gases are Released to the Atmosphere	42
16.0	PRESENTING THE RESULTS OF THE INVENTORY	43
	REFERENCES	54

ANNEXES

A	GREENHOUSE GAS EMISSIONS FROM STATIONARY FOSSIL FUEL COMBUSTION – OVERVIEW OF METHODS IN EXISTING PROTOCOLS	A1
B	GREENHOUSE GAS EMISSIONS FROM KRAFT MILL LIME KILNS AND CALCINERS	B1
C	CH ₄ AND N ₂ O EMISSIONS FROM BIOMASS COMBUSTION – OVERVIEW OF METHODS IN EXISTING PROTOCOLS	C1
D	GREENHOUSE GAS EMISSIONS ATTRIBUTABLE TO IMPORTS AND EXPORTS OF POWER AND STEAM – OVERVIEW OF METHODS IN EXISTING PROTOCOLS	D1
E	ALLOCATING GREENHOUSE GAS EMISSIONS FROM COMBINED HEAT AND POWER (CHP) SYSTEMS – RECOMMENDED GUIDANCE AND REVIEW OF METHODS	E1
F	GREENHOUSE GASES FROM VEHICULAR TRAFFIC AND MACHINERY – OVERVIEW OF METHODS IN EXISTING PROTOCOLS	F1
G	GREENHOUSE GASES FROM WASTE MANAGEMENT AT PULP AND PAPER MILLS – RECOMMENDED APPROACH AND REVIEW OF EXISTING METHODS	G1
H	ALLOCATING GREENHOUSE GAS EMISSIONS FROM PARTLY OWNED OR PARTLY CONTROLLED SOURCES – OVERVIEW OF METHODS IN EXISTING PROTOCOLS	H1
I	SUPPORTING INFORMATION ON BIOMASS	I1
J	REFERENCES FOR ANNEXES A THROUGH I	J1

TABLES

Table 1.	Emission Factor Ranges Useful in Identifying Significant and Insignificant Sources of GHGs	12
Table 2.	IPCC Default CO ₂ Emission Factors for Fossil Fuels	14
Table 3.	IPCC Tier 2 Uncontrolled CH ₄ and N ₂ O Emission Factors for Industrial Boilers	16
Table 4.	Emission Factors for Kraft Mill Lime Kilns and Calciners	20
Table 5.	Emission Factors for Calcium- and Sodium-Carbonate Make-up in the Pulp Mill	22
Table 6.	Emission Factors for CH ₄ and N ₂ O from Biomass Combustion	25
Table 7.	Default Fuel Economy and Emission Factors for Different Types of Mobile Sources and Activity Data	34
Table 8.	Fuel Consumption-Based Emission Factors for Non-Road Mobile Sources and Machinery	35
Table 9.	Recommended Default Values for k and L ₀ for Estimating Mill Landfill Methane Emissions	39
Table 10.	Table to Report Operational Boundaries of the Inventory	45
Table 11.	Table to Report GHG Inventory Results – Direct Emissions	46
Table 12.	Table to Report GHG Inventory Results – Indirect Emissions	47
Table 13.	Table to Report Emission Factors Used to Prepare the Inventory	48
Table 14.	Example GHG Inventory Results – Operational Boundaries of the Inventory	49
Table 15.	Example GHG Inventory Results – Direct Emissions	51
Table 16.	Example GHG Inventory Results – Indirect Emissions	52
Table 17.	Example GHG Inventory Results – Emission Factors Used to Prepare the Inventory	53

FIGURES

Figure 1.	Schematic for Example Inventory Results	50
-----------	---	----

CALCULATION TOOLS FOR ESTIMATING GREENHOUSE GAS EMISSIONS FROM PULP AND PAPER MILLS

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 product industry's unique attributes
- establish a framework that would 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. 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 detail on estimation methods. The Annexes contain many of the country-specific data and factors published by national authorities. The information in the Annexes was current as of the end of 2001.

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) or other accepted protocols for corporate GHG inventories. These protocols provide valuable information on issues ranging from defining the objectives for a GHG inventory to options for verifying the results – issues beyond the scope of the industry-specific calculation tools in this report.

¹ IPCC has developed methods that countries are using to characterize sequestration (IPCC 1997a, b, c, 2000b), and a great deal of work is underway to improve the understanding of sequestration and its measurement. Some of these studies are summarized by Skog and Nicholson 1998; Apps et al. 1999; Matthews 1996; and Birdsey 1996.

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, social, 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 since it can help extend the time during which carbon is stored in products. It has been estimated that, on a global basis, the amount of carbon stored in forest products is increasing by 139 million metric tons of carbon per year (Winjum et al. 1998).

The forest products industry relies heavily on climate-neutral biomass fuels that reduce atmospheric levels of greenhouse gases by displacing fossil fuels. In a number of countries, more than half of the industry's energy requirements are met using biomass fuels. Forest products that cannot be economically recycled provide another 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 than 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 of 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, project accounting, 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 these principles are generic and information is available in a variety of other places.

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

- the Intergovernmental Panel on Climate Change (IPCC) (IPCC 1997a, b, c, 2000a)
- the World Resources Institute/World Business Council for Sustainable Development (WRI/WBCSD) (WRI 2001a)
- the PEW Center on Global Climate Change (Loreti, Wescott, and Isenberg 2000; Loreti, Foster, and Obbagy 2001)

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 the following generic, but important, issues:

- GHG accounting and reporting principles (e.g., organizational and operational boundary determination, relevance, completeness, consistency, transparency, and accuracy)
- defining corporate objectives for inventories (e.g., public reporting, voluntary initiatives, carbon trading)
- establishing baselines and accounting for reductions
- 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 those derived from IPCC guidelines and best practices and 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 adequate for reporting under the WRI/WBCSD GHG Protocol. In specific, 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 not yet published calculation tools for these emissions, but IPCC has 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 Purpose of the Calculation Tools

These tools have been developed to help achieve the following outcomes:

- ensure credible and transparent emissions estimates for GHGs of potential significance to pulp and paper mills; i.e., fossil-CO₂, CH₄ (methane), and N₂O (nitrous oxide)
- provide companies with methods that are tailored to the conditions likely to be encountered at pulp and paper mills and are easily implemented
- minimize the potential for inappropriate mill-to-mill, company-to-company, and international comparisons of GHG emissions
- facilitate the tracking of improvements at individual sites or companies
- facilitate carbon trading
- be as consistent as possible with recognized international and national protocols

Although the tools are focused on pulp and paper mills, they are generally applicable to wood products facilities as well. These tools do not deal with operations unique to wood products manufacturing, but NCASI will be developing a set of tools tailored to the needs of those facilities.

4.2 Steps Involved in Applying the Calculation Tools

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

4.2.1 *Determining the Objectives of the Inventory*

The WRI/WBCSD GHG Protocol can help companies understand the variety of uses for GHG inventory results (WRI 2001a). 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 the objectives of the inventory.

4.2.2 *Identifying Boundary Conditions*

There are two types of boundaries that must be considered in a GHG inventory – operational boundaries and organizational boundaries. The operational boundaries define the operations and emission sources that need to be included to satisfy the objectives of the inventory. The organizational boundaries dictate the ownership of the emissions and determine whether the emissions are “direct” or “indirect.”

Direct and indirect emissions are defined as follows (WRI 2001a):

- **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 from 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 address only a limited set of indirect emissions – those associated with transfers of electrical power, steam, and heat – and these are the indirect emissions addressed in these calculation tools.

The tools have been developed anticipating that most companies will select operational boundaries that include:

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

Core operations are those associated with the pulp and papermaking process. 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.

4.2.3 Estimating Emissions from Sources within the Operational Boundaries

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

- CO₂ emissions from stationary fossil fuel combustion
- CH₄ and N₂O emissions from fossil fuel-fired units, recovery furnaces, biomass boilers, and lime kilns
- CO₂ emissions from make-up CaCO₃ or Na₂CO₃ used in the pulp mill
- CO₂ emissions from on-site vehicles and machinery
- CH₄ emissions attributable to mill wastes in landfills and anaerobic waste treatment operations
- emissions from other off-site core operations (e.g., company-owned harvesting equipment and company-owned truck fleets)
- fossil fuel-derived CO₂ exported to satellite precipitated calcium carbonate (PCC) plants
- imports of CO₂ (e.g., for pH neutralization)
- GHG emissions associated with power and steam imports
- GHG emissions attributable to power and steam exports

Emissions of climate-neutral biomass-derived CO₂ are addressed in Annex I.

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 most likely be small in relation to the GHG emissions categories listed above, more information can be obtained in the EPA publication *Protocol for Equipment Leak Emission Estimates* (USEPA 1995).

4.2.4 *Determining Organizational Boundaries and Ownership of Emissions*

In addition to setting operational boundaries, the company will need to identify the organizational boundaries, or in other words, the boundaries that dictate ownership of emissions from the sources within the operational boundaries. A company's organizational boundaries will include those on-site and off-site emissions from sources that the company "owns or controls" (determined by using one of a variety of methods discussed later). Indirect emissions are outside the organizational boundaries of the inventory because, by definition, indirect emissions "occur from sources owned or controlled by another company" (WRI 2001a). Additional discussion of operational and organizational boundaries is presented below and is available in the WRI/WBCSD GHG Protocol (WRI 2001a).

4.2.5 *Presenting Results*

The calculation tools emphasize the disaggregated and transparent presentation of results. The suggested format for reporting results provides the company with an opportunity to provide the following information.

- operations included within the operational boundaries of the inventory
- direct emissions
- indirect emissions and emissions attributable to exports of power and steam
- exports and imports of fossil fuel-derived CO₂
- emission factors used to develop the inventory

Annex I suggests a format for reporting supporting information on biomass.

4.3 *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 is 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 will be acceptable for companies to estimate GHG emissions using emission factors and corresponding "activity data" (e.g., amount of fuel used or miles traveled). 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 CO₂ emissions from these sources are directly related to fuel carbon content as reflected in widely accepted emission factors.

For most other sources, however, the quality of GHG emission estimates is much lower, sometimes because of inadequate activity data, but more often due to emission factors that are based on very few data. Because of the importance of emission factors to the results of a

GHG inventory, these calculation tools include a table (Table 13) that companies are encouraged to use to show the emission factors used to develop the inventory.

It can be expected that many more emissions 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, in the process, the estimates will be adjusted upward or downward. 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.

4.4 Units

Different countries use different units of measure. This can create considerable confusion when emission factors and estimation techniques are applied internationally. To reduce the confusion, the SI (metric) system is used throughout this report, but the 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.

4.4.1 Units of Measure for Greenhouse Gases

Greenhouse gases are often compared on the basis of their estimated potential to cause global warming. Factors have been developed, called Global Warming Potentials (GWPs), which can be used to convert a quantity of non-CO₂ greenhouse gas into an amount of CO₂ with an equivalent warming potential. Although the derivation of these factors involves a large number of assumptions, GWPs are almost universally used to compare one greenhouse gas to another. The GWP for CH₄ is 21 so, from the standpoint of potential global warming, every gram of CH₄ is equivalent to 21 grams of CO₂. The GWP for N₂O is 310. The derivation of these factors is explained elsewhere (IPCC 1996).² When an emission estimate is the sum of several GHGs expressed as the equivalent amount of CO₂, the estimate is said to be in CO₂-equivalents, sometimes abbreviated as CO₂e, CO₂eq, or CO₂-equiv. To convert CO₂, CH₄, and N₂O emissions into CO₂-equivalents, multiply CH₄ emissions by 21 and N₂O emissions by 310, then add both to CO₂ emissions.

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

For purposes of transparency and to avoid confusion, in these calculation tools greenhouse gas quantities are usually reported in terms of the mass of the individual GHG, rather than

² Recent research summarized in IPCC 2001 suggests that the GWP for CH₄ should be higher (23) and that for N₂O should be lower (296) than the values previously recommended by IPCC (1996). However, the revised GWPs have not been widely adopted at this time. Therefore, this report uses the GWP values recommended by IPCC (1996) (21 for CH₄ and 310 for N₂O).

CO₂-equivalents or MTCEs. In some cases, however, companies may find that it is appropriate to use emission factors that are based on the combined emissions of several GHGs expressed in terms of CO₂-equivalents or MTCEs. This is acceptable provided it is made clear in the results.

4.4.2 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 difference between these measures is that GCV and HHV include the heat of condensation of water formed during combustion of the fuel. A common approximation is that NCV is 95% of GCV for coal and oil and 90% of GCV for natural gas.

In this report, NCV (LHV) is used. In some cases, the emission factors have been converted from GCV (HHV) units 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 IDENTIFYING CORE PULP AND PAPER OPERATIONS TO BE INCLUDED WITHIN THE OPERATIONAL BOUNDARIES OF THE INVENTORY

A number of operations are integral to pulp and papermaking. In this report, these operations are defined as “core operations.” In many cases, companies will want to include these core operation emissions within the operational boundaries of the inventory:

- direct emissions (i.e., company-owned emissions) from core operations that are on-site (e.g., pulp mills, paper mills, power boilers)
- direct emissions from off-site core operations (e.g., company-owned harvesting equipment and truck fleets)
- indirect emissions from on-site core operations that are wholly owned or partly owned by another entity (including outsourced power islands)
- off-site indirect emissions related to power and steam imports
- on-site emissions attributable to power and steam exports

While companies may deviate from these boundary conditions based upon their particular needs, it is important that the results be presented with a clear explanation of the operations and emissions included within the boundaries of the inventory. A table is included in the calculation tools (Table 10) which can be used to document the core operations within the boundaries of the inventory and the ownership of those operations (i.e., the operational and organizational boundaries of the inventory). Companies may use other formats to summarize this information, but a description of the inventory boundaries and the core operations included in the inventory should be included in the inventory results.

Considerations involved in setting operational boundary conditions for inventories and for assigning ownership to emissions (i.e., setting organizational boundaries) are addressed in the WRI/WBCSD GHG Protocol (WRI 2001a).

Examples of core operations that might be included in the operational boundaries of a GHG inventory for an individual pulp and paper mill, as well as examples of several non-core operations that would normally not be included (although they might be included in a corporate inventory), are listed here.

Examples of core pulp and paper mill operations with the potential to emit greenhouse gases:

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

- 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, 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, waste treatment and disposal or emissions control

Examples of operations that would not be core operations at pulp and paper mills:

- panel plants or wood chemical plants located at the mill site

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

Companies are encouraged to include within the operational boundaries of the inventory outsourced core operations that significantly impact the facility's GHG profile. The indirect emissions from outsourced power islands, in particular, can be responsible for a large fraction of the GHG emissions associated with a mill site.

The company must use its judgment to determine what is meant by an "on-site" operation. If the company feels that its interpretation of the term "on-site" is important to understanding the results of the inventory, this can be explained in the results. In most cases, however, the ownership of the source (i.e., the organizational boundaries) will be much more important than its location in determining how to handle its emissions in the inventory.

6.0 DETERMINING THE ORGANIZATIONAL BOUNDARIES OF THE INVENTORY AND OWNERSHIP OF EMISSIONS

Ownership and control determine the organizational boundaries for GHG inventories. Direct emissions, i.e., emissions from sources that the company owns or controls, are within the company's organizational boundaries and indirect emissions are outside those boundaries. For purchases of electricity or steam, the situation is usually straightforward, because the emissions are usually from sources outside the company's ownership and control and are therefore indirect. The reporting format suggested in these calculation tools divides emissions along organizational boundary lines; i.e., into direct and indirect emissions.

Companies using these calculation tools, however, may encounter situations where inventory boundaries include operations that are only partly owned by the company. Some or all of the emissions from these sources might be "owned" by other entities and would therefore be accounted for as indirect emissions. These situations often arise due to outsourcing and partial ownership arrangements, which are becoming increasingly common in the pulp and paper industry. 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

There are a large number of possible ownership arrangements, making it difficult to provide specific instructions on how to derive organizational boundaries and determine ownership of GHG emissions from these sources. Perhaps the most thorough discussion of methods for determining the ownership of emissions from partly owned or partly controlled sources is contained in the WRI/WBCSD GHG Protocol (WRI 2001a). Annex H to this report contains an overview of the WRI/WBCSD guidelines. Companies performing inventories that require allocating ownership of emissions from partly owned sources will want to obtain the WRI/WBCSD GHG Protocol (WRI 2001a). The approach outlined in the GHG Protocol can be summarized as follows.

Where the allocation of GHGs is specified contractually, this allocation is to be used. Otherwise the WRI/WBCSD GHG Protocol suggests that allocation be done two ways, according to control and according to equity share. The GHG Protocol recommends that the results of both approaches be presented. The GHG Protocol emphasizes that organizational boundaries developed for allocating GHGs “should be consistent with the organizational boundaries which have been drawn up for financial reporting purposes” (WRI 2001a).

GHG allocation will often be governed by contractual arrangements and financial accounting standards that will vary from situation to situation and between legal jurisdictions. For these reasons, these calculation tools do not recommend a method for determining ownership of emissions from partially owned sources. Companies should select methods that are most appropriate for particular situations and should describe the methods in the inventory results.

7.0 MATERIALITY AND INSIGNIFICANT EMISSIONS

Greenhouse gas protocols generally allow facilities to ignore emissions that are so small that they do not significantly impact the estimate of overall emissions. This concept of “materiality” is drawn from financial reporting, where a material difference is sometimes taken to be a discrepancy of more than 5% between reported and audited values (though this is not an absolute standard) (Loretti et al. 2001). There is no generally accepted standard, however, for materiality in GHG inventories (WRI 2001a; Loretti et al. 2001). Indeed, the WRI/WBCSD GHG Protocol points out that “what is considered material will ... depend on the needs of users and the size of a company and its emissions sources.” It goes on to observe that “the materiality of a source can only be established after it has been assessed. This implies that [it] can be included in the inventory – even if it is just an estimate” (WRI 2001a).

These tools contain no specific recommendations on how to determine whether emissions are so small that they can be ignored in preparing a GHG inventory, but they contain emission factors and example calculations that may aid companies in deciding which emissions are material and which are not. The decision on whether, or how, the estimates should be reported must be left to the company. 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 identify the materiality threshold that was used.

Table 1 has been developed from representative emission factors discussed in the Annexes to this report. 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 suggested default values for the factors. The factors in Table 1 clearly illustrate the importance of CO₂ emissions from fossil fuel combustion. In most cases, CH₄ and N₂O contribute relatively small quantities to a mill’s GHG emissions, even on a CO₂-equivalents basis. In addition, sources other than fossil fuel combustion will be comparatively small. Other sections of this report contain example calculations that will be helpful in identifying insignificant sources. The ultimate decision on which emissions to include, however, must be made by the company.

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

	Units	Fossil-CO ₂	CH ₄ (CO ₂ -equiv.)*	N ₂ O (CO ₂ -equiv.)*	Tables in Report Containing Default Values
Natural gas used in boilers	kg CO ₂ -equiv./TJ	56,100-57,000	13 – 357	31 – 620	2, 3
Residual oil used in boilers	kg CO ₂ -equiv./TJ	76,200 – 78,000	13 – 63	93 – 1550	2, 3
Coal used in boilers	kg CO ₂ -equiv./TJ	92,900-126,000	15 – 294	155 – 29,800 ^o	2, 3
Bark and wood waste fuel	kg CO ₂ -equiv./TJ	0	<21 – 860	<310 – 8060	6
Black liquor	kg CO ₂ -equiv./TJ	0	42 – 630	1550	6
Lime kilns	kg CO ₂ -equiv./TJ	Depends on fuel	21 – 57	0 ^w	2, 4
Lime calciners	kg CO ₂ -equiv./TJ	Depends on fuel	21 – 57	1550 ^λ	2, 4
Pulp mill make-up CaCO ₃	kg CO ₂ / t CaCO ₃	440	0	0	5
Pulp mill make-up Na ₂ CO ₃	kg CO ₂ / t Na ₂ CO ₃	415	0	0	5
Diesel fuel used in vehicles	kg CO ₂ equiv./TJ	74,000 – 75,300	82 – 231	620 – 9770	7, 8
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	8
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	8
Anaerobic wastewater treatment	kg CO ₂ eq/ kg COD treated	0	5.25 ^η	0	Equations 6 and 7
Mill solid waste landfills	kg CO ₂ eq/ dry ton solid waste	0	3,500 [∞]	0	Equations 3,4,5 and Table 9

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

^o Reported N₂O emission factors greater than 1500 kg CO₂ eq./TJ are generally limited to fluidized bed boilers

^w IPCC information suggests N₂O is not likely to be formed in lime kilns in significant amounts.

^λ Amounts of N₂O, if any, formed in calciners is not known, so the largest factor for fuels normally used in kilns is shown here.

^η Assumes no capture of gas from the treatment plant.

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

In the results of the inventory, companies should identify those situations where emissions have been estimated to be too small to materially impact the inventory results. The reporting format 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.

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 CO₂ are estimated from the carbon content of, or emission factors for, all fossil fuels being burned. In some cases, a correction (i.e., a reduction) is made for unburned carbon. Companies can use data from one of the following sources, with the preferred sources listed first.

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

CO₂ emission factors and information on fossil fuel carbon content and unburned carbon are available from most national authorities and a variety of existing protocols. Some of this information is included in Annex A to this report. In cases where the Annex contains both country-specific information and IPCC information, the country-specific information may be preferred because it may reflect country-specific data on fuel carbon content. The IPCC generic emission factors are shown in Table 2.

To correct CO₂ emissions estimates for unburned 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 corrected for unburned carbon, and as uncorrected. IPCC points out, however, that in the case of coal, unburned carbon can be much higher than the default values and cites an Australian study of coal-fired boilers wherein unburned carbon ranged from 1 to 12% of the carbon fed to the boiler.

In many cases, it will be possible to estimate the total CO₂ emissions from all sources burning a single fossil fuel without estimating the emissions from each unit separately. For instance, if a mill is burning natural gas in a boiler for steam production and in several infrared dryers, the CO₂ emissions from natural gas burning can be estimated from the total gas used for both purposes.

If the mill exports fossil fuel-derived CO₂, for instance to an adjacent precipitated calcium carbonate (PCC) plant, these exports should not be included in the emissions estimates because this CO₂ is not emitted by the mill. A separate line is included in the results table (Table 12) to report exports of fossil fuel-derived CO₂.

Table 2. IPCC Default CO₂ 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 unburned carbon. To account for unburned carbon, IPCC suggests multiplying by these default factors: coal = 0.98, oil = 0.99, and gas = 0.995.

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

8.2 Methane and Nitrous Oxide

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

Companies will often be able to use the data in Table 1 to demonstrate that emissions of CH₄ and N₂O from fossil fuel combustion are insignificant compared to CO₂ emissions. In other cases, a single emission factor might be available that includes fossil-CO₂, CH₄, and N₂O

emissions expressed as CO₂ equivalents. In this case, the company does not need to report the three gases separately.

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

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

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

IPCC provides Tier 1 and Tier 2 emission factors for methane and nitrous oxide. IPCC's Tier 2 emission factors, shown in Table 3, are usually preferred because they are more specific to fuel type and combustion device. Tier 2 emission factors, however, are based on uncontrolled emissions. This is unimportant for methane because emission control devices have little impact on methane emissions (IPCC 1997c). Nitrous oxide emissions can be impacted by control devices, but the data are very limited (IPCC 1997c). Where N₂O emissions are important to inventory results, companies may want to develop emissions data. In most cases, however, the difference between controlled and uncontrolled emissions is expected to have little effect on total GHG emissions. Therefore, companies will probably want to use the Tier 2 emission factors shown in Table 3 unless other factors are available that are more suited to individual mill circumstances. The table presents IPCC's Tier 2 emission factors for the fossil fuels and combustion devices of most interest to the pulp and paper industry.

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

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

Recovery furnaces – In most cases, only small amounts of fossil fuel are burned in recovery furnaces. The CO₂ 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 CH₄ and N₂O. 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 CH₄ and N₂O from liquor burning. The CH₄ and N₂O emissions factors for recovery furnaces are included in the Section 11.2.

Table 3. IPCC Tier 2 Uncontrolled CH₄ and N₂O Emission Factors for Industrial Boilers (IPCC 1997c)

Fuel	Technology	Configuration	kg CH ₄ /TJ	kg N ₂ O/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.

Combination fuel-fired boilers burning biomass and fossil fuels – The CO₂ releases from fossil fuel used in these boilers can be estimated using the methods described in Section 8.1. In most cases, the combustion conditions in these boilers are more like those in biomass-fired boilers than fossil fuel-fired boilers. Therefore, unless data are available from site-specific testing on other similar boilers burning a comparable mix of fuels, it is recommended that the emissions from combination fuel-fired boilers be estimated from the total heat input to the boiler and CH₄ and N₂O emission factors for biomass. These emission factors are summarized in Section 11.2.

Kraft mill lime kilns and calciners – The emissions from lime kilns and calciners are unique enough to warrant separate discussion.

Gas-fired infrared dryers, incinerators, and other miscellaneous pulp and paper sources – The CO₂ 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 emission factors 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 CH₄ and N₂O are so small that they can be ignored in the inventory. The fossil CO₂ from these sources can be estimated directly from the carbon content of the fuel or CO₂ emission factors, using the same methods as for other stationary combustion units.

Example Calculation: CO₂, CH₄, and N₂O 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 CO₂/TJ (after correcting for 0.5% unoxidized carbon). The mill uses the CH₄ and N₂O emission factors from Table 3 (1.4 kg CH₄/TJ and 0.1 kg N₂O/TJ). The mill estimates the heating value of the natural gas to be 52 TJ/kiloton and the density to be 0.8 kg/standard cubic meter. The annual emissions are estimated as follows.

CO₂ emissions:

- $(17 \times 10^6 \text{ m}^3 \text{ gas/y}) \times (0.8 \text{ kg/m}^3) = 13.6 \times 10^6 \text{ kg gas/y} = 13.6 \text{ kiloton gas/y}$
- $(13.6 \text{ kiloton gas/y}) \times (52 \text{ TJ/kiloton}) = 707 \text{ TJ/y}$
- $(707 \text{ TJ/y}) \times (55.9 \text{ t CO}_2/\text{TJ}) = 39,500 \text{ t CO}_2/\text{y}$

CH₄ emissions

- $(707 \text{ TJ NCV/y}) \times (1.4 \text{ kg CH}_4/\text{TJ NCV}) = 990 \text{ kg CH}_4/\text{y} = 0.99 \text{ t CH}_4/\text{y}$
- Using the IPCC GWP of 21, this is equal to 21 t CO₂-eq./y

N₂O emissions

- $(707 \text{ TJ NCV/y}) \times (0.1 \text{ kg N}_2\text{O}/\text{TJ NCV}) = 70.7 \text{ kg N}_2\text{O}/\text{y} = 0.07 \text{ t N}_2\text{O}/\text{y}$
- Using the IPCC GWP of 310, this is equal to 22 t CO₂-eq./y

Total GHG emissions = 39,500 + 21 + 22 = 39,500 t CO₂-equivalents/y

On a CO₂-equivalents basis, CH₄ and N₂O emissions are barely 0.1% of CO₂ 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 CH₄ and N₂O 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 0.1% of CO₂ emissions.

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

The boiler produces 350,000 kg steam per hour (about 770,000 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: CO₂ 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 CH₄ and N₂O from Table 3. The IPCC Tier 2 emission factors for dry bottom, wall fired boilers burning pulverized bituminous coal are 0.7 kg CH₄/TJ NCV and 1.6 kg N₂O/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 CO₂, CH₄, and N₂O are estimated as follows.

CO₂ emissions:

- $(336,000 \text{ Mg/y coal}) \times (0.801 \text{ Mg carbon / Mg coal}) \times (0.98 \text{ Mg carbon burned}) \times (44 \text{ Mg CO}_2 / 12 \text{ Mg carbon}) = 967,000 \text{ Mg CO}_2/\text{yr}$ or $967 \times 10^3 \text{ t CO}_2/\text{yr}$

CH₄ emissions:

- $370,000 \text{ short tons coal/y} = 740 \times 10^6 \text{ pounds/y}$
- $(740 \times 10^6 \text{ pounds/y}) \times (13,000 \text{ Btu HHV/pound}) = 9.62 \times 10^{12} \text{ Btu HHV/y}$
- for coal, LHV is 0.95 times HHV (see Section 4.4.2)
- $(9.62 \times 10^{12} \text{ Btu HHV/y}) \times (0.95 \text{ to correct to LHV}) = 9.14 \times 10^{12} \text{ Btu LHV/y}$
- $(9.14 \times 10^{12} \text{ Btu LHV/y}) \times (1055 \text{ J/Btu}) = 9.64 \times 10^{15} \text{ J NCV/y} = 9.64 \times 10^3 \text{ TJ NCV/y}$
- $\text{CH}_4 \text{ emissions} = (9.64 \times 10^3 \text{ TJ NCV/y}) \times (0.7 \text{ kg CH}_4/\text{TJ NCV}) = 6.75 \times 10^3 \text{ kg CH}_4/\text{y}$ or $6.75 \text{ t CH}_4/\text{y}$

Using the IPCC GWP of 21 for CH₄, this equates to 142 t CO₂-eq./y

N₂O emissions:

- $\text{N}_2\text{O emissions} = (9.64 \times 10^3 \text{ TJ NCV/y}) \times (1.6 \text{ kg N}_2\text{O/TJ NCV}) = 15.4 \text{ t N}_2\text{O/yr}$

Using the IPCC GWP of 310 for N₂O, is to 4780 t CO₂-eq./y

Total GHG emissions = $967,000 + 142 + 4,780 = 972,000 \text{ t CO}_2\text{-equivalents/y}$

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

CO₂ emissions = 967,000 t CO₂/y

CH₄ emissions = 142 t CO₂-eq./y or 0.015% of CO₂ emissions

N₂O emissions = 4,780 t CO₂-eq./y or only about 0.5% of CO₂ emissions

Case 2: CO₂ 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 CO₂ is 94.6 t CO₂/TJ NCV. The mill decides that the default IPCC correction for unburned carbon in coal-fired boilers (2% unburned carbon) is appropriate.

CO₂ emissions:

- 370,000 short tons coal/y = 740×10^6 pounds/y
- $(740 \times 10^6 \text{ pounds/y}) \times (13,000 \text{ Btu HHV/pound}) = 9.62 \times 10^{12} \text{ Btu HHV/y}$
- for coal, LHV is 0.95 times HHV (see Section 4.4.2)
- $(9.62 \times 10^{12} \text{ Btu HHV/y}) \times (0.95 \text{ to correct to LHV}) = 9.14 \times 10^{12} \text{ Btu LHV/y}$
- $(9.14 \times 10^{12} \text{ Btu LHV/y}) \times (1055 \text{ J/Btu}) = 9.64 \times 10^{15} \text{ J NCV/y} = 9.64 \times 10^3 \text{ TJ NCV/y}$
- uncorrected CO₂ emissions = $(9.64 \times 10^3 \text{ TJ NCV/y}) \times (94.6 \text{ t CO}_2 / \text{TJ NCV}) = 912 \times 10^3 \text{ t CO}_2/\text{y}$
- CO₂ emissions corrected for 2% unburned carbon = $894 \times 10^3 \text{ t CO}_2/\text{y}$

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

CO₂ emissions = 894,000 t CO₂/y

CH₄ emissions = 142 t CO₂-eq./y or 0.016% of CO₂ emissions

N₂O emissions = 4,780 t CO₂-eq./y or only about 0.5% of CO₂ emissions

As in the previous example, this comparison suggests that it may be relatively simple for many mills to document that emissions of CH₄ and N₂O 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-CO₂ 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 CO₂ emissions are reported together with other fossil fuel-related CO₂ emissions.

Although CO₂ is also liberated from the CaCO₃ burned in the kiln or calciner, the carbon released from CaCO₃ is climate-neutral 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 climate-neutral biomass-related emissions as “supporting information” using Annex I. The movement of carbon in kraft pulp mills and the reasons for differentiating biomass- from fossil-CO₂ emissions from lime kilns are explored in detail in Annex B to this report and in a paper by Miner and Upton (2002).

There are very few data on CH₄ and N₂O 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 CH₄/TJ. For commercial lime kilns,

IPCC suggests emission factors of 1.0 and 1.1 kg CH₄/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, CH₄ emissions will be very small compared to the CO₂ from fossil fuel.

No data were found for N₂O from lime kilns or calciners, but the temperatures in rotary lime kilns appear to be too high to allow significant generation of N₂O (see Annex B for more information). It is reasonable, therefore, to assume that N₂O emissions from rotary lime kilns are negligible. The temperatures in calciners appear to be more amenable to N₂O generation (see Annex B). Given the range of N₂O emission factors for oil and gas, however, it seems likely that N₂O emissions will be small relative to fossil-CO₂ emissions from fossil fuel-fired calciners.

The emission factors suggested for kraft mill lime kilns and calciners are summarized in Table 4.

Table 4. Emission Factors for Kraft Mill Lime Kilns and Calciners

Fuel	Emissions, kg/TJ					
	Kraft mill lime kilns			Kraft mill calciners		
	CO ₂	CH ₄	N ₂ O	CO ₂	CH ₄	N ₂ O
Residual oil	76,600*	2.7 ^θ	0 ^ζ	76,600*	2.7 ^θ	0.3 ^φ
Distillate oil	73,400*	2.7 ^θ	0 ^ζ	73,400*	2.7 ^θ	0.4 ^φ
Natural gas	55,900*	2.7 ^θ	0 ^ζ	55,900*	2.7 ^θ	0.1 ^φ
Biogas	0	2.7 ^θ	0 ^ζ	0	2.7 ^θ	0.1 ^φ

* from Table 2, corrected for unburned carbon

^θ from NCASI 1981

^ζ based on IPCC description of temperatures giving rise to N₂O emissions

^φ from Table 3

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). Because these so-called “satellite” PCC plants are not present at most mills, and because they are almost always owned by a separate company, they are not considered core operations in these calculation tools.

A separate line is included in the inventory results to show the amounts of fossil fuel CO₂ being exported to PCC plants. These exports of fossil fuel-derived CO₂ 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 climate-neutral biomass-derived CO₂ that are exported with lime kiln stack gas, it can include this as supporting information (see Annex I).

A mill may sometimes export CO₂ 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 CO₂ and cannot control whether the PCC plant uses it. Presumably, if the PCC plant were to conduct an inventory, any unused fossil-CO₂ received from the mill would be shown as a direct emission in its inventory. Exports of fossil fuel CO₂ to PCC plants are shown in the results table (Table 12). This table is also used to show any imports of CO₂ to the mill, for use in neutralization, for instance.

These draft calculation tools do not address the ultimate fate of exported CO₂ or the ownership of any CO₂ that is ultimately emitted from the PCC plant, as both issues are outside the boundary of core 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 in 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 28.6×10^6 pounds of gas last year with a typical heat content of 21,000 Btu HHV/lb and a density of 0.77 kg/m³. The IPCC CO₂ emission factor for natural gas from boilers can be used for lime kilns since the CO₂ emissions are a function only of gas composition. The IPCC CO₂ emission factor for natural gas is 55.9 t CO₂/TJ (after correcting for 0.5% unoxidized carbon). For CH₄, the mill decides to use the only available emission factor for kraft mill lime kilns (2.7 kg CH₄/TJ) and assumes that N₂O emissions are negligible based on the IPCC discussion of temperatures needed to generate N₂O. The kiln's GHG emissions are estimated as follows.

CO₂ emissions:

- 28.6×10^6 pounds gas/y \times 21,000 Btu HHV/lb = 601×10^9 Btu HHV/y
- for natural gas, LHV is 0.9 times HHV (see Section 4.4.2)
- 601×10^9 Btu HHV/y \times 0.9 (to convert to LHV) = 541×10^9 Btu LHV/y
- 541×10^9 Btu/y \times (1.055×10^{-6} GJ/Btu) = 570,000 GJ/y = 570 TJ/y
- 570 TJ/y \times 55.9 t CO₂/TJ = 31,900 t CO₂/y

CH₄ emissions:

- 570 TJ/y \times 2.7 kg CH₄/TJ = 1540 kg CH₄/yr

Using the IPCC CO₂ equivalency factor of 21, this equals 32 t CO₂-equivalents. This is a very small number compared to the CO₂ 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 CH₄ emissions from this source are non-material to the inventory.

N₂O emissions:

- As discussed above and in more detail in Annex B, IPCC's analysis of the temperatures needed to form N₂O in combustion processes suggests that it is unlikely that significant amounts of N₂O 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 CO₂-equivalents/y

10.0 CARBON DIOXIDE EMISSIONS FROM MAKE-UP CHEMICALS

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 source does not need to be addressed (although it can be included as Supporting Information on Biomass in Annex I).

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 5.

Table 5. 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 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.

- $(7000 \text{ t } \text{CaCO}_3/\text{y}) \times 440 \text{ kg } \text{CO}_2/\text{t } \text{CaCO}_3 = 3,080,000 \text{ kg } \text{CO}_2/\text{y} = 3080 \text{ t } \text{CO}_2/\text{y}$

11.0 EMISSIONS FROM STATIONARY COMBUSTION OF BIOMASS FUELS

11.1 Climate-Neutral Carbon Dioxide Emissions from Burning Biomass Fuels

Many pulp and paper mills generate more than half of their energy needs from climate-neutral 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 formed when atmospheric carbon dioxide is sequestered by trees during growth and transformed into organic carbon substances. When these biomass fuels are burned, the CO₂ emitted during the manufacturing and combustion processes is the atmospheric carbon dioxide that was sequestered during growth of the tree; hence, there is no net contribution to the atmospheric CO₂ level. This carbon cycle is a closed loop. New tree growth keeps absorbing atmospheric carbon dioxide and maintains the cycle.

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

Therefore, in keeping with well-established practices, the greenhouse gas inventory results generated using these calculation tools do not include CO₂ emissions from biomass burning. The WRI/WBCSD GHG Protocol and some national reporting schemes, however, require that these climate-neutral emissions be estimated and reported as “supporting information.” Annex I contains information that will assist companies that want to comply with these requirements.

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

- wood and wood waste (although biogas from wood waste 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

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

11.2 Methane and Nitrous Oxide Emissions from Burning Biomass Fuels

Although CO₂ from biomass burning is almost universally excluded from GHG inventories, CH₄ and N₂O from biomass burning are sometimes included. Calculation tools are provided, therefore, to assist in estimating these emissions.

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

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 6 provides a summary of the available information on methane and nitrous oxide emissions from biomass boilers. 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.

Where an emission factor shown in the table was developed for circumstances that match conditions at a mill, the company may want to select that emission factor for estimating mill 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. These median emission factors fall within the ranges cited in the CORINAIR emissions inventory (ranges also shown in the table) (EEA 1999).

Combination fuel-fired boilers burning biomass and fossil fuels – In most cases, the combustion conditions in these 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 wastes. Therefore, unless data are available from site-specific testing on other 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 waste boilers, it is recommended that the emissions from combination fuel-fired boilers be estimated from the total heat input to the boiler and CH₄ and N₂O emission factors for biomass.

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

Emission Factor Description	kg CH ₄ /TJ	kg N ₂ O/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 2001
<i>Median emission factors for wood waste</i>	<i>12</i>	<i>4</i>	
	1 - 40	1.4 – 75	EEA 1999
Recovery furnaces			
Recovery furnace	<1	<1	Fortum 2001
Recovery furnace – black liquor	2.5 ^Ω	-	JPA 2002
Black Liquor	30	5	Swedish EPA 2001
<i>Median emission factors for black liquor</i>	<i>2.5</i>	<i>2</i>	
	1 – 17.7	1 – 21.4	EEA 1999

* converted from GCV to NCV assuming a 5% difference

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

^λ based on heat content of 20 GJ/t dry solids

^Ω based on liquor heat content of 13.3 GJ/t dry solids

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 6.9×10^6 GJ of bark and 0.8×10^6 GJ of residual fuel oil. Because the boiler receives supplemental fossil fuel, it is necessary to estimate the CO₂ from the fossil fuel use and the CH₄ and N₂O emissions based on the total firing rate. The mill decides to use the IPCC emission factor for residual oil (76.6 t CO₂/TJ, after correcting for 1% unoxidized carbon) and to estimate CH₄ and N₂O emissions based on the total firing rate and the emission factors developed by Fortum on CFB boilers. The average emission factors found by Fortum, shown in Table 6, are 1 kg CH₄/TJ and 8.8 kg N₂O/TJ.

CO₂ emissions from fossil fuel:

- $(0.8 \times 10^6 \text{ GJ/y}) = (0.8 \times 10^3 \text{ TJ/y})$
- $(0.8 \times 10^3 \text{ TJ/y}) \times (76.6 \text{ t CO}_2/\text{TJ}) = 61,300 \text{ t CO}_2/\text{y}$

CH₄ emissions:

- total heat input = $(6.9 \times 10^6 \text{ GJ/y}) + (0.8 \times 10^6 \text{ GJ/y}) = 7.7 \times 10^6 \text{ GJ/y} = 7.7 \times 10^3 \text{ TJ/y}$
- $7.7 \times 10^3 \text{ TJ/y} \times 1 \text{ kg CH}_4/\text{TJ} = 7,700 \text{ kg CH}_4/\text{y} = 7.7 \text{ t CH}_4/\text{y}$

Using the IPCC warming potential of 21, this equates to 162 t CO₂-eq./y.

N₂O emissions:

- total heat input = $7.7 \times 10^3 \text{ TJ/y}$
- $7.7 \times 10^3 \text{ TJ/y} \times 8.8 \text{ kg N}_2\text{O}/\text{TJ} = 67,800 \text{ kg N}_2\text{O}/\text{y} = 67.8 \text{ t N}_2\text{O}/\text{y}$

Using the IPCC warming potential of 310, this equates to 21,000 t CO₂-eq./y

Total CO₂ equivalents emitted = $61,300 + 162 + 21,000 = 82,500 \text{ t CO}_2\text{-equivalents/y}$

12.0 EMISSIONS ATTRIBUTABLE TO IMPORTS AND EXPORTS OF ELECTRICITY AND STEAM

The consumption of power or steam (or hot water) 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 2001a). 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. (Sources for national and regional information for several countries are identified in Annex D.) It is often difficult, however, to determine whether published emission factors for electrical power include all GHGs or only CO₂ emissions. The difference is usually unimportant because CO₂ represents the great majority of the emissions in most situations. For purposes of these calculation tools, therefore, it is assumed that purchased power emission factors address all GHGs and are reported in CO₂ equivalents. Where emission factors are available for individual gases associated with electrical power, the individual gases can be reported separately and then combined into carbon dioxide equivalents, or the individual emission factors can be combined into a single CO₂-equivalents emission factor.

Electrical power transmission losses vary from location to location. In some cases, they are so significant that they provide an important rationale for distributed power generation. However, published GHG emission factors for purchased power seldom incorporate the effects of transmission losses. Furthermore, accepted GHG protocols seldom ask users of electrical power to account for transmission losses. For these reasons, these tools recommend the use of emission factors for purchased power that do not include transmission losses. If transmission losses are particularly important, however, this can be noted in the results and the impact can be estimated in supporting information.

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

12.2 Netting Imports and Exports

In some cases, facilities both import and export electricity. Because of the controversies about estimating indirect emissions impacts, however, netting of imports and exports is a controversial practice. The WRI/WBCSD GHG Protocol, for instance, specifically requires that the emissions impacts of exports be reported separately, as “supporting information,” rather than together with indirect emissions from imports, and netting is specifically prohibited (WRI 2001a). Therefore, companies wanting to follow the WRI/WBCSD GHG Protocol (a) should not net imports and exports, and (b) should report the emissions from imports and exports separately. These calculation tools employ estimation methods and reporting formats consistent with the WRI/WBCSD requirements.

12.3 Electricity Imports

To estimate indirect emissions associated with imported power, 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 will 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 12.7. 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 CO₂ eq./kWh (see Annex D). The indirect emissions associated with the purchased power are estimated as follows.

- 83,300 MWh/y = 83.3×10^6 kWh/y
- $(83.3 \times 10^6 \text{ kWh/y}) \times (0.991 \text{ kg CO}_2\text{-eq./kWh}) = 82.6 \times 10^6 \text{ kg CO}_2\text{-eq./y}$
= 82,600 t CO₂-eq./y

12.4 Electricity Exports

To be consistent with accepted GHG accounting protocols, 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. The result tables, however, allow the mill to separately show those emissions attributable to exported power and steam. The tables also allow companies to compare the carbon intensity of exported power (in kg CO₂/MWh) to the carbon intensity of the power on the grid into which the power is exported. Companies may find this a helpful tool 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 associated emissions.

These calculation tools use the method recommended by WRI/WBCSD for estimating the emissions impact of exported power. This method 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 (described in Section 12.7) to estimate the emissions attributable to the exported power.

In the inventory results, companies can show the carbon intensity of the exported power or steam (e.g., in kg CO₂/MWh or kg CO₂/GJ) compared to the carbon intensity of the grid into which the power or steam is exported. To estimate the carbon intensity of the grid, the 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 it is more appropriate.

12.5 Steam Imports

In many cases where steam is imported by a mill, the steam 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 12.7. In other cases, the contractual arrangement between the mill and power producer may define how the emissions from the power plant are to be allocated between the power and the steam sold by the power plant. In these cases, the allocation should be explained in the results. If the imported steam is not generated in a CHP system, best professional judgment must be used to estimate the emissions reported by the 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.

12.6 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. 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 below 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., one GJ of hot water energy is assumed to be equivalent to one GJ of steam energy, thermal losses during generation of hot water from mill-generated steam are assumed to be negligible).

12.7 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 E.) The efficiency method is recommended because it attempts to relate the energy outputs to the amounts of fuel used to generate them and, by extension, to the GHGs produced in generating them. Where a company uses an alternative method, the method should be explained in the results.

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

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.

12.7.1 *Simplified Efficiency Method*

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

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

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

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

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

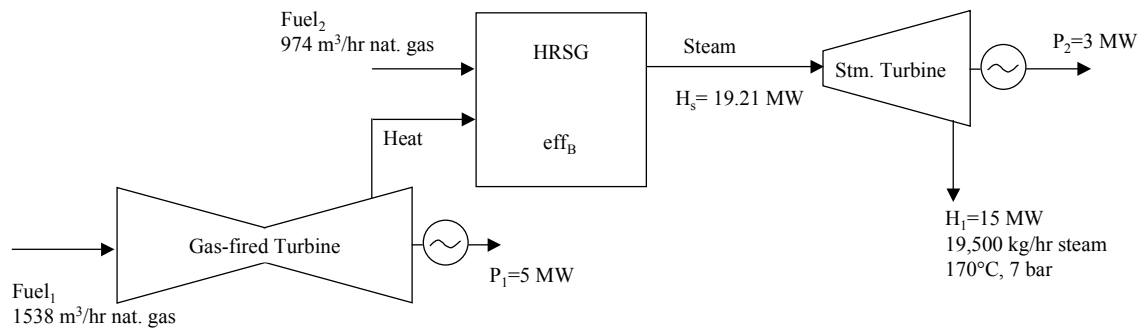
where: E_P = emissions share attributable to electric power production

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

In using the simplified efficiency method, WRI/WBCSD recommends that an efficiency of 0.35 be used for power generation and 0.8 be used for steam (or hot water) generation (WRI 2001b, c), corresponding to a ratio of efficiencies (R_{eff}) of 2.3. The first example calculation below makes use of these recommended default efficiency factors.

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

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; 0.35 for power generation and 0.8 for steam generation (WRI 2001b, 2001c).



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

Total system emissions:

Fuel₁:

$$\text{CO}_2 \quad (1538 \text{ m}^3/\text{hr}) \times (0.039 \text{ GJ/m}^3) \times (55.9 \text{ kg CO}_2/\text{GJ}) = 3353 \text{ kg CO}_2/\text{hr}$$

$$\text{CH}_4 \quad (1538 \text{ m}^3/\text{hr}) \times (0.039 \text{ GJ/m}^3) \times (0.0006 \text{ kg CH}_4/\text{GJ}) \times (21 \text{ CO}_2\text{-eq.} / \text{CH}_4) \\ = 0.76 \text{ kg CO}_2\text{-eq.}/\text{hr}$$

$$\text{N}_2\text{O} \quad (1538 \text{ m}^3/\text{hr}) \times (0.039 \text{ GJ/m}^3) \times (0.0001 \text{ kg N}_2\text{O} / \text{GJ}) \times (310 \text{ CO}_2\text{-eq.} / \text{N}_2\text{O}) \\ = 1.86 \text{ kg CO}_2\text{-eq.}/\text{hr}$$

$$\text{Total Fuel}_1 \text{ emissions} = 3356 \text{ kg CO}_2\text{-eq.}/\text{hr}$$

Fuel₂:

$$\text{CO}_2 \quad (974 \text{ m}^3/\text{hr}) \times (0.039 \text{ GJ/m}^3) \times (55.9 \text{ kg CO}_2/\text{GJ}) = 2123 \text{ kg CO}_2/\text{hr}$$

$$\text{CH}_4 \quad (974 \text{ m}^3/\text{hr}) \times (0.039 \text{ GJ/m}^3) \times (0.0014 \text{ kg CH}_4/\text{GJ}) \times (21 \text{ CO}_2\text{-eq.} / \text{CH}_4) \\ = 1.12 \text{ kg CO}_2\text{-eq.}/\text{hr}$$

$$\text{N}_2\text{O} \quad (974 \text{ m}^3/\text{hr}) \times (0.039 \text{ GJ/m}^3) \times (0.0001 \text{ kg N}_2\text{O} / \text{GJ}) \times (310 \text{ CO}_2\text{-eq.} / \text{N}_2\text{O}) \\ = 1.18 \text{ kg CO}_2\text{-eq.}/\text{hr}$$

$$\text{Total Fuel}_2 \text{ emissions} = 2126 \text{ kg CO}_2\text{-eq.}/\text{hr}$$

$$\text{Total CHP system emissions} = 3356 + 2126 = 5482 \text{ kg CO}_2\text{-eq.}/\text{hr}$$

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

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

$$E_H = \left\{ \frac{15 \text{ MW}}{15 \text{ MW} + (8 \text{ MW} \times 2.3)} \right\} \times 5482 \text{ kg CO}_2 \text{ eq} = 2462 \text{ kg CO}_2 \text{ eq} = 20,681 \text{ t CO}_2 \text{ eq/y at 350 d/y operation}$$

$$E_P = 5482 \text{ kg CO}_2 \text{ eq} - 2462 \text{ kg CO}_2 \text{ eq} = 3020 \text{ kg CO}_2 \text{ eq} = 25,368 \text{ t CO}_2 \text{ eq/yr at 350 d/y operation}$$

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 = $100 \times 2462 / 5482 = 44.9\%$
- Percentage of CHP emissions to power output = $100 \times 3020 / 5482 = 55.1\%$

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 = $(2462 \text{ kg CO}_2\text{-eq.}/\text{hr}) / 15 \text{ MW}$
= $164.1 \text{ kg CO}_2\text{-eq.}/\text{MWh}$
- Emission factor for CHP power output = $(3020 \text{ kg CO}_2\text{-eq.}/\text{hr}) / 8 \text{ MW}$
= $377.5 \text{ kg CO}_2\text{-eq.}/\text{MWh}$

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. The WRI/WBCSD GHG Protocol includes these emissions in its Scope 1 level of reporting and recommends that they be included in all inventories. Because companies may want to include these emissions in corporate GHG inventories, 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 Gases from On-Road Vehicles

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

If companies use fuel consumption statistics to estimate CO₂ emissions, the estimates are derived using exactly the same approach as used for stationary fossil fuel combustion sources, described in Section 8. If, on the other hand, the company finds it more convenient to develop the emissions estimate from statistics on distance traveled, the emission factors in Table 7 can be used (WRI 2001d).

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

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

Vehicle Characteristics			Emission Factor
Vehicle Type	Liters/100km	Mpg	gram CO ₂ / km
New small gas/electric hybrid	4.2	56	100.1
Small gas auto, hghwy	7.3	32	175.1
Small gas auto, city	9.0	26	215.5
Med gas auto, hghwy	7.8	30	186.8
Med gas auto, city	10.7	22	254.7
Large gas automobile, hwy	9.4	25	224.1
Large gas automobile, city	13.1	18	311.3
Med station wagon, hwy	8.7	27	207.5
Med 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 automobile	11.2	21	266
Diesel automobile	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

Emission factors for these sources have been published in a number of places. Some of the available information is summarized in Annex F. IPCC's guidelines contain several different sets of emission factors without recommending a single set (IPCC 1997c). Table 8 is from one of the sources cited by IPCC. The CO₂ factors in the table are from Table 2 and are slightly different than those in the original table in IPCC 1997c. The table also includes overall CO₂-equivalent emission factors developed using the IPCC global warming potentials for CH₄ (21) and N₂O (310). Emission factors for CH₄ and N₂O from these sources vary from one protocol to another. The differences in N₂O, in particular, can impact the CO₂-equivalents by as much as 10%. Where companies need precise estimates for these sources, it is recommended that the various sources discussed in Annex F be examined to determine which emission factors are most appropriate. In most cases, however, the emission factors in Table 8 will be adequate.

Table 8. Fuel Consumption-Based 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 ₂ O 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 CO₂-equivalent emission factors in Table 8 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 CO₂-equiv./TJ = 21,500 kg CO₂-equiv./y = 21.5 t CO₂-equiv./y
- Gasoline used in 2-stroke engines = 10,000 l/y x 0.1 = 1,000 l/y
- 1,000 l/y x 0.034 GJ/liter = 34 GJ/y = 0.034 TJ/y
- 0.034 TJ/y x 72,300 kg CO₂-equiv./TJ = 2460 kg CO₂-equiv./y = 2.5 t CO₂-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 CO₂-equiv./TJ = 629,000 kg CO₂-equiv./y = 629 t CO₂-equiv./y

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

- 21.5 + 2.5 + 629 = 653 t CO₂-equiv./y

14.0 GREENHOUSE GAS EMISSIONS FROM MILL WASTE IN LANDFILLS

These calculation tools have been developed assuming that many companies will include mill-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. The reporting format, however, has been prepared assuming that only the emissions from company-owned landfills will be reported.

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

An emission factor for landfilled waste was presented in Table 1. This factor is based on a number of conservative assumptions and, in most cases, is expected to produce estimates that are higher than the actual emissions attributable to landfilled mill waste. The emission factor can be useful in deciding whether landfill emissions are material to the results of the

inventory. The methods described below, however, are recommended for preparing an estimate to use in the inventory results.

14.1 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'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 that 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 only 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. The alternative approach is 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%, it means that 100 tons of methane were generated.

The problem with this approach is that the effectiveness of landfill gas collection systems is variable and uncertain. Reported collection efficiencies range from 60 to 85% (USEPA 1998). This variability and uncertainty has caused IPCC to take the position that "the use of undocumented estimates of landfill gas recovery potential is not appropriate, as such estimates tend to overestimate the amount of recovery" (IPCC 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, if not many, cases 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 mill 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 1998). These calculation tools also assume that all of the methane that is captured and burned is converted to biomass CO₂ and therefore does not have to be included in the inventory.

Using these default values and assumptions, estimates of methane releases can be developed using Equation 3.

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

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

14.2 Estimating Landfill Methane Emissions at Mill Landfills without Gas Collection Data

14.2.1 Simplified First Order Decay Approach

Where the approach described above 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 CH₄ emissions from active and inactive landfills.

In cases where the annual deposits are constant (or are assumed to be) 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.

$$CH_4 \text{ (m}^3\text{/y) generated from all waste in the landfill} = R L_0 (e^{-kC} - e^{-kT}) \quad (\text{Eq. 4})$$

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

Not all methane that is generated is subsequently released to the atmosphere. To estimate atmospheric releases, use the result from Equation 4 in Equation 5. For landfills with modern gas collection and combustion systems but no measurements of quantities of gas collected, the amount of methane recovered can be assumed to be 75% of that generated (USEPA 1998).

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

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

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

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

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

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 G identifies a number of sources for the parameter values L_0 and k needed in Equation 4. Unfortunately, the values vary considerably from one protocol to the next and the values are based on very few data. For situations where pulp and paper mill wastewater treatment sludge is a major constituent 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 mill 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 mill wastes, companies should use the parameter values shown in Table 9.

Table 9. Recommended Default Values for k and L_0 for Estimating Mill 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 landfill, IPCC suggests a variation of this approach. Using this variation, starting in year one, calculate how much methane will be generated in each subsequent year by waste deposited in that year using Equations 6 and 7.

$$CH_4 \text{ generated in a given year by waste deposited in an earlier year } (m^3/y) = k R_y L_0 (e^{-k(T-Y)}) \quad (\text{Eq. 6})$$

where k = methane generation rate constant, 1/yr

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

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

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

Y = year after landfill opened that waste was disposed

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

$$CH_4 (m^3/y) \text{ released} = [(CH_4 \text{ generated} - CH_4 \text{ recovered}) * (1 - OX)] + [CH_4 \text{ recovered} * (1 - FRBURN)] \quad (Eq. 7)$$

where: $CH_4 \text{ generated}$ = from Equation 5

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

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

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

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 9.

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 m³/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 m³/y x 0.47 = 385,000 m³/y
 - methane generated = (385,000 m³/y) / 0.75 = 513,000 m³/y
 - methane released = (513,000 – 385,000)m³/y x (1- 0.1) = 115,000 m³/y = 115 x 10⁶ l/y
 - methane released = (115 x 10⁶ l/y) / 22.4 l/g-mole = 5.13 x 10⁶ g-mole/y
 - methane released = (5.13 x 10⁶ g-mole/y) x 16 g/g-mole = 82 x 10⁶ g/y = 82 t CH₄/y
- Using the IPCC GWP (21), this is equal to 1720 t CO₂-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 L₀ shown in Table 9 (100 m³/Mg for L₀ and 0.03 y⁻¹ for k).

$$R = 50 \text{ Mg/d} \times 350 \text{ d/y} = 17500 \text{ Mg/y}$$

$$L_0 = 100 \text{ m}^3/\text{Mg}$$

$$k = 0.03/\text{y}$$

$$C = 0 \text{ y}$$

$$T = 20 \text{ y}$$

- methane generated (m³/y) = 17,500 x 100 x (e^{-0.03 x 0} – e^{-0.03 x 20}) = 790,000 m³/y
- density of methane (0°C and 1 atm. pressure) = 0.72 kg/m³ (from Perry's Chemical Engineers' Handbook)
- methane generated (kg/y) = 790,000 m³/y x 0.72 kg/m³ = 568,000 kg/y = 568 t/y
- assume 10% oxidation in landfill cover
- methane released = 568 t/y x (1 – 0.1) = 511 t CH₄ /y released

Using the IPCC GWP (21), this equals 10,700 t CO₂-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 CO₂-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 current GHG protocols do not attempt to estimate emissions from aerobic and facultative treatment operations.

Even for anaerobic systems, only CH₄ emissions need to be estimated. The CH₄ emissions from mill-owned anaerobic systems will be reported as direct emissions. The CO₂ emitted from wastewater and sludge treatment operations contains biomass carbon which is not included in most GHG inventories. In addition, N₂O 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 CO₂ produced in burning the CH₄ contains biomass carbon, it does not need to be reported in the inventory results. 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 8 (IPCC 2000a). Although the IPCC document allows the equation to be applied to systems that are not completely anaerobic (by multiplying the result by an arbitrary adjustment factor of less than one), there

are no data currently available to support the selection of the adjustment factor. It is recommended, therefore, that methane emissions only be estimated from anaerobic treatment or sludge digestion systems until factors for other types of systems are available.

$$\text{Anaerobic Treatment Plant Methane Emissions (kg/y)} = (OC \times EF) - B \quad (\text{Eq. 8})$$

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

If the solids are handled separately, emissions from sludge digestion would be calculated using Equation 9. In cases where sludge is burned, it is included in the calculations for GHG emissions from biomass burning discussed in Section 11.

$$\text{Anaerobic Sludge Digestion Plant Methane Emissions (kg/y)} = (OCs \times EFs) - B \quad (\text{Eq. 9})$$

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

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 CH₄ generation from anaerobic treatment systems is 0.25 kg CH₄/kg COD in the feed. The CH₄ emissions are calculated as follows.

- $OC = 10,000 \text{ kg/d} \times 300 \text{ d/y} = 3,000,000 \text{ kg COD/y}$
- $CH_4 \text{ generated} = 3,000,000 \text{ kg COD/y} \times 0.25 \text{ kg CH}_4/\text{kg COD} = 750,000 \text{ kg CH}_4/\text{y}$
 $= 750 \text{ t CH}_4/\text{y}$

Using the IPCC GWP (21), this equals 15,750 t CO₂-equiv./y

16.0 PRESENTING THE RESULTS OF THE INVENTORY

These calculation tools include a suggested 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 with 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 10 provides a format for identifying the core operations that have been included within the operational inventory boundaries and who owns them. Companies

are encouraged to include any additional information that will help explain the boundaries or the results of the inventory.

Table 11 is 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.

Table 12 is for recording indirect emissions (i.e., emissions from sources within the operational boundaries of the inventory but owned by another entity), emissions attributable to exports of power and steam, and imports and exports of fossil fuel-derived CO₂. Companies are encouraged to use this form to characterize the impact of electricity and steam transfers as well as outsourced operations (power islands in particular) that have a significant impact on a facility's greenhouse gas profile.

Table 13 is 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 14 through 17 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 climate-neutral CO₂ from biomass combustion as supporting information. Annex I includes a table (Table 4) that can be used for this purpose.

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

Table 10. Table to Report Operational Boundaries of the Inventory

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

General description of Operational Boundaries:			
Use this space to provide additional information helpful to understanding the operational boundaries of the inventory, including the method used to allocate emissions from partly-owned or –controlled sources. Attach additional pages if needed.	Completely Owned by Company	Partly Owned by Company	Owned by other entity
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 noncondensable gases, etc.			
Wastepaper pulping and cleaning			
Deinking			
Bleaching of chemical or semichemical pulp			
Brightening of deinked pulp			
On-site preparation of chemicals used in core operations (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:			

emissions from sources that are wholly or partially owned or controlled by the company

<p>Write “NA” to show an item is not applicable. For instance, if the mill has no biomass boilers, write NA in the boxes for biomass combustion. Where emissions have been determined to be insignificant or non-material, write “NM” and explain the basis for the determination in a footnote.</p>		Total Direct Emissions – metric tons			
		CO ₂	CH ₄	N ₂ O	CO ₂ Equiv ¹
	<i>Process and Energy-Related Emissions</i>				
1	Stationary Fossil Fuel Combustion				
2	Biomass Combustion	0.0			
3	Make-up Chemicals (CaCO ₃ and Na ₂ CO ₃)				
	<i>Transportation and machinery emissions</i>				
4	On-road vehicles				
5	Off-road vehicles and machinery				
	<i>Waste management emissions</i>				
6	Landfill emissions from mill wastes	0.0			
7	Anaerobic wastewater treatment systems	0.0			
8	<i>Other Direct Emissions not included above – Explain:</i>				
	Total Direct Emissions (Sum of lines 1 through 8)				
<p>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.</p>					
<p>Include any other information that is needed to understand the inventory results:</p>					

¹ CO₂ Equivalents are calculated multiplying individual gases by IPCC GWP values, CO₂=1, CH₄=21, N₂O=310, and summing across all three gases. It is acceptable to use emission factors for CO₂-equivalents rather than estimating the three gases individually.

emissions attributable to power/steam exports, and imports/exports of fossil CO₂

Emissions attributable to power/steam exports, and imports; exports of fossil CO ₂		Metric tons			
		CO ₂	CH ₄	N ₂ O	CO ₂ Equiv ¹
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.					
Indirect emissions related to electricity and steam imports, including those from outsourced power islands					
1	Indirect Emissions related to electricity imports				
2	Indirect Emissions related to steam imports				
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:				
Emissions associated with exported electricity and steam					
5	Emissions related to electricity exports				
	Carbon intensity of electricity exports (kg CO ₂ /MWh)				
	Carbon intensity of grid receiving electricity exports (kg CO ₂ /MWh)				
	Method used to estimate GHG intensity of grid:				
6	Emissions related to steam exports				
7	Total emissions attributable to exports (Sum of lines 5 and 6)				
Imports and Exports of fossil fuel-derived CO ₂					
8	Imports of CO ₂ (e.g., for neutralization)				
9	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 I – Supporting Information on Biomass. Note 2: This exported CO ₂ should <i>not</i> be reported as an emission in Table 11.					
Explain the method used to determine ownership of emissions from sources partly owned by the company. Use the WRI/WBCSD GHG Protocol for guidance on determining ownership.					
Include any other information needed to understand the inventory results:					

¹ CO₂ Equivalents are calculated multiplying individual gases by IPCC GWP values, CO₂=1, CH₄=21, N₂O=310, and summing across all three gases. It is acceptable to use emission factors for CO₂-equivalents rather than estimating the three gases individually

Table 14. Example GHG Inventory Results - Operational Boundaries of the Inventory

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

General description of Operational Boundaries:			
Use this space to provide additional information helpful to understanding the operational boundaries of the inventory, including the method used to allocate emissions from partly-owned or –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.	Completely Owned by Company	Partly Owned by Company	Owned by other entity
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 noncondensable 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 used in core operations (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			X
Gas-fired infrared dryers	X		
Other fossil fuel-fired dryers			
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			X
Other Operation – describe:			
Other Operation – describe:			

Schematic for Example Inventory Results

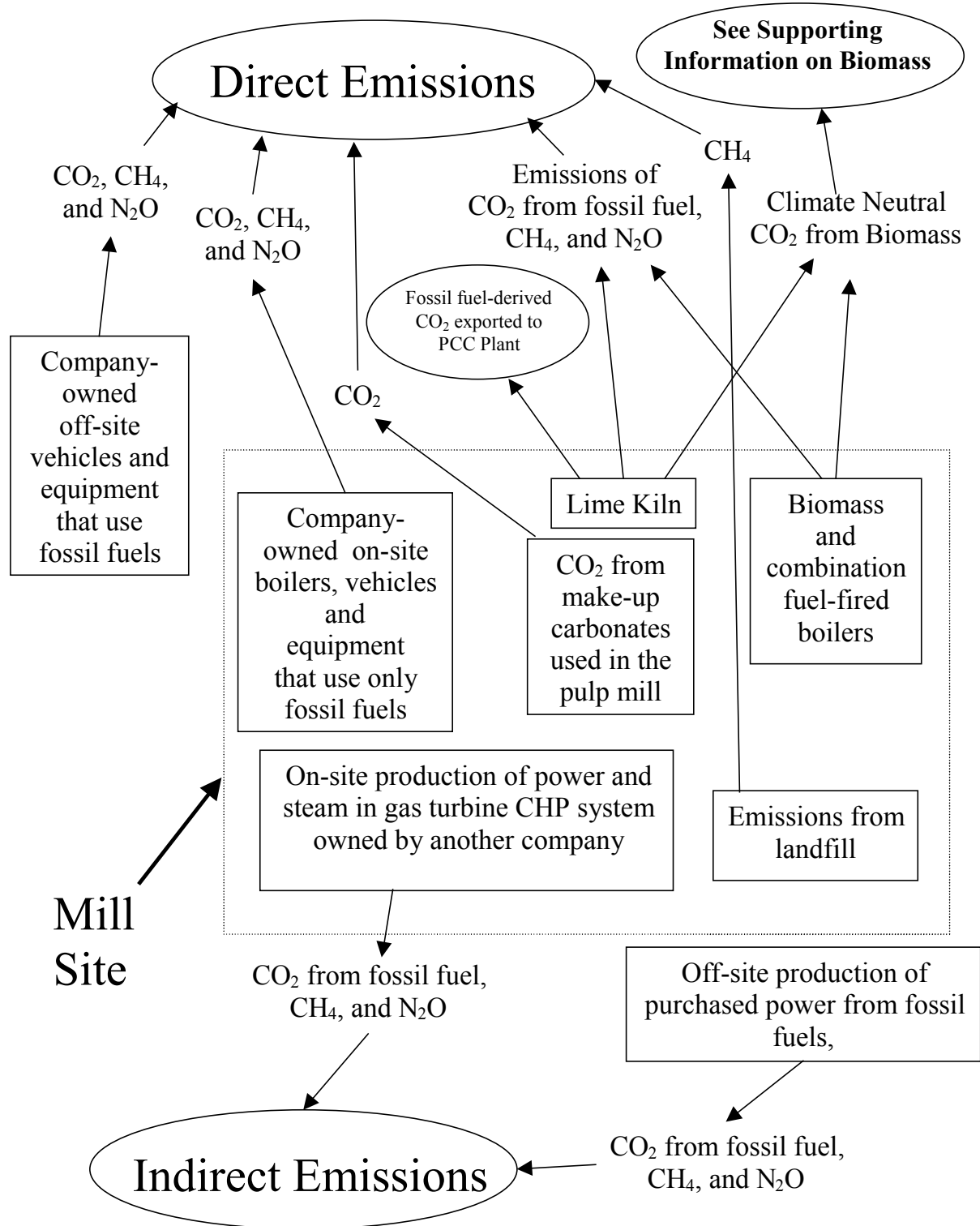


Figure 1. Schematic for Example Inventory Results

Table 15. Example GHG Inventory Results - Direct Emissions
emissions from sources that are wholly or partially owned or controlled by the company

Write "NA" to show an item is not applicable. For instance, if the mill has no biomass boilers, write NA in the boxes for biomass combustion. Where emissions have been determined to be insignificant or non-material, write "NM" and explain the basis for the determination in a footnote.		Total Direct Emissions – metric tons			
		CO ₂	CH ₄	N ₂ O	CO ₂ Equiv ¹
	<i>Process and Energy-Related Emissions</i>				
1	Stationary Fossil Fuel Combustion	720000	100	80	746900
2	Biomass Combustion	0.0	120	40	14920
3	Make-up Chemicals (CaCO ₃ and Na ₂ CO ₃)	5500	0	0	5500
	<i>Transportation and machinery emissions</i>				
4	On-road vehicles	>>>	>>>	>>>	320
5	Off-road vehicles and machinery	NM*	NM*	NM*	NM*
	<i>Waste management emissions</i>				
6	Landfill emissions from mill wastes	0.0	511	NA	10730
7	Anaerobic wastewater treatment systems	0.0	NA	NA	NA
8	<i>Other Direct Emissions not included above – Explain:</i>				
	Total Direct Emissions (Sum of lines 1 through 8)	>>>	>>>	>>>	778370
<p>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.</p> <p>Include any other information that is needed to understand the inventory results:</p> <p>* 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).</p> <p>¹ CO₂ Equivalents are calculated multiplying individual gases by IPCC GWP values, CO₂=1, CH₄=21, N₂O=310, and summing across all three gases. It is acceptable to use emission factors for CO₂-equivalents rather than estimating the three gases individually.</p>					

Table 16. Example GHG Inventory Results - Indirect Emissions
emissions attributable to power/steam exports, and imports/exports of fossil CO₂

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.		Metric tons					
		CO ₂	CH ₄	N ₂ O	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	>>>	>>>	>>>	72000		
2	Indirect Emissions related to steam imports	>>>	>>>	>>>	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		
Emissions associated with exported electricity and steam							
5	Emissions related to electricity exports	0	6	2	746		
	Carbon intensity of electricity exports (kg CO ₂ /MWh)	<10					
	Carbon intensity of grid receiving electricity exports (kg CO ₂ /MWh)	726					
	Method used to estimate GHG intensity of grid:						
6	Emissions related to steam exports	0	0	0	0		
7	Total emissions attributable to exports (Sum of lines 5 and 6)	0	6	2	746		
Imports and Exports of fossil fuel-derived CO ₂							
8	Imports of CO ₂ (e.g., for neutralization)	0					
9	Exports of fossil fuel-derived CO ₂ (e.g., to PCC Plants)	21000					
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 I – Supporting Information on Biomass.							
Note 2: This exported CO ₂ should <i>not</i> be reported as an emission in Table 11.							
Explain the method used to determine ownership of emissions from sources partly owned by the company. Use the WRI/WBCSD GHG Protocol for guidance on determining ownership.							
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 ₂ O=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 17. Example GHG Inventory Results - Emission Factors (EF) Used to Prepare the Inventory

		CO ₂	CH ₄	N ₂ O	CO ₂ Equiv	Source of EF
Fossil Fuel Combustion						
Fuel	Combustion Units					
Gasoline	forestry equip.	NA	NA	NA	74.7 t/TJ	Table 10
Diesel fuel	trucks and machinery	NA	NA	NA	82.4 t/TJ	Table 10
Coal	boiler	94.6 t/TJ	0.7 kg/TJ	1.6 kg/TJ	NA	Tables 4 & 5
Natural gas	lime kiln	56.1 t/TJ	2.7 kg/TJ	0	NA	Table 6
Residual fuel oil	recovery furnace	77.4 t/TJ	2.5 kg/TJ	2 kg/TJ	NA	Tables 4 & 8
Biomass Combustion						
Fuel	Combustion Unit					
bark & wood waste	boiler	0.0	12 kg/TJ	4 kg/TJ	NA	Table 8
		0.0				
		0.0				
		0.0				
		0.0				
		0.0				
		0.0				
		0.0				
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						

REFERENCES

- AEA Technology. 2001. *UK greenhouse gas inventory 1990-1999: Annual report for submission under the Framework Convention on Climate Change*. Oxfordshire, England: National Environmental Technology Centre.
<http://ariadne.aeat.co.uk/netcen/airqual/reports/ghg/ghg2.html> (26 Nov. 2001)
- Apps, M.J., Kurz, W.A., Beukema, S.J., and Bhatti, J.S. 1999. Carbon budget of the Canadian forest product sector. *Environmental Science and Policy* No. 2. pg 25-41. Elsevier Science Ltd.
- Birdsey, R.A.. 1996. Chapter 1 – Carbon storage for major forest types and regions in the conterminous United States. *Forests and global change – Vol 2: Forest Management Opportunities for Mitigating Carbon Emissions*. Sampson, N., and Hair, D. (eds). Washington, DC: American Forests.
- European Environment Agency (EEA). 1999. *EMEP/CORINAIR Atmospheric emission inventory guidebook - Second ed*. Copenhagen, Denmark.
<http://reports.eea.eu.int/EMEPCORINAIR/en> (26 Nov. 2001).
- Fortum Power and Heat Oy. 2001. *Methane and nitrous oxide emissions in the Finnish energy production*. Fortum, Filand: Fortum Power and Heat Oy, Technology.
- International Energy Agency (IEA). 1998. *The role of bioenergy in greenhouse gas mitigation*. Paris: International Energy Agency.
http://www.ieabioenergy.com/media/6_pospapa4.pdf (14 Feb. 2002).
- Intergovernmental Panel on Climate Change (IPCC). 1996. *Climate change 1995, the science of climate change*. New York: Cambridge University Press
- Intergovernmental Panel on Climate Change (IPCC). 1997a. *Revised 1996 IPCC guidelines for national greenhouse gas inventories: Reporting instructions (Vol 1)*. IPCC National Greenhouse Gas Inventory Program.
<http://www.ipcc-nggip.iges.or.jp/public/gl/invs4.htm> (26 Nov. 2001).
- Intergovernmental Panel on Climate Change (IPCC). 1997b. *Revised 1996 IPCC guidelines for national greenhouse gas inventories: Workbook (Vol 2)*. IPCC National Greenhouse Gas Inventory Program. <http://www.ipcc-nggip.iges.or.jp/public/gl/invs5.htm> (26 Nov. 2001).
- Intergovernmental Panel on Climate Change (IPCC). 1997c. *Revised 1996 IPCC guidelines for national greenhouse gas inventories: Reference manual (Vol 3)*. IPCC National Greenhouse Gas Inventory Program.
<http://www.ipcc-nggip.iges.or.jp/public/gl/invs6.htm> (20 Nov. 2001).
- Intergovernmental Panel on Climate Change (IPCC). 2000a. *Good practice guidance and uncertainty management in national greenhouse gas inventories*. IPCC National Greenhouse Gas Inventory Program.
<http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm> (26 Nov. 2001).

- Intergovernmental Panel on Climate Change (IPCC). 2000b. *IPCC special report on land use, land-use change, and forestry*. Cambridge University Press. pp 375.
http://www.grida.no/climate/ipcc/land_use/ (16 April 2002).
- Intergovernmental Panel on Climate Change (IPCC). 2001. *Third assessment report (TAR), climate change 2001: The scientific basis*. Working Group 1 Report, Technical Summary. IPCC National Greenhouse Gas Inventory Program.
<http://www.ipcc.ch/activity/tar.htm> (31 October 2002).
- Japan Paper Association (JPA). 2002. *Various personal communications between JPA and Reid Miner of NCASI*. Tokyo: Japan Paper Association.
- Loreti, C.P., Foster, S.A., and Obbagy, F.E. 2001. *An overview of greenhouse gas emissions verification issues*. Cambridge, MA: A.D. Little.
http://www.pewclimate.org/projects/emissions_verification.cfm (28 Nov. 2001).
- Loreti, C.P., Wescott, W.F., and Isenberg, M.A. 2000. *An overview of greenhouse gas inventory issues*. Cambridge, MA: A.D. Little.
<http://www.pewclimate.org/projects/greenhouse.cfm> (28 Nov. 2001).
- Matthews, R. 1996. The influence of carbon budget methodology on assessments of the impacts of forest management on the carbon balance. *Forest ecosystems, forest management and the global carbon cycle*. Apps and Price (eds.). Berlin Heidelberg: Springer-Verlag.
- Miner, R., and Upton, B. 2002. Methods for estimating greenhouse gas emissions from lime kilns at kraft pulp mills. *Energy* 27(8):729-738.
- National Council for Air and Stream Improvement, Inc. (NCASI). 1980. *A study of wood-residue fired power boiler total gaseous non-methane organic emissions in the Pacific Northwest*. Air Quality Technical Bulletin No.109. Research Triangle Park, NC: National Council for Air and Stream Improvement, Inc.
- National Council for Air and Stream Improvement, Inc. (NCASI). 1981. *A study of the kraft process lime kiln total gaseous non-methane organic emissions*. Technical Bulletin No. 358. Research Triangle Park, NC: National Council for Air and Stream Improvement, Inc.
- National Council for Air and Stream Improvement, Inc. (NCASI). 1985. *Volatile organic carbon emissions from wood residue fired power boilers in the Southeast*. Technical Bulletin No.455. Research Triangle Park, NC: National Council for Air and Stream Improvement, Inc.
- National Council for Air and Stream Improvement, Inc. (NCASI). 1999. *Evaluation of the EPA-recommended approach to predicting air emissions from pulp and paper landfills*. Technical Bulletin No.790. Research Triangle Park, NC: National Council for Air and Stream Improvement, Inc.

- Skog, K.E., and Nicholson, G.A. 1998. Carbon cycling through wood products: The role of wood and paper products in carbon sequestration. *Forest Products Journal* 48(7/8).
- Swedish Environmental Protection Agency. 2001. *Sweden's national inventory report 2001 – Submitted under the United National Convention on Climate Change*. Stockholm: Swedish Environmental Protection Agency. <http://www.environ.se/dokument/fororen/klimat/klimat/fccdata/NIR2001.pdf> (26 Nov. 2001).
- United States Environmental Protection Agency (USEPA). 1995. *Protocol for equipment leak emission estimates, November 1995*. Washington, DC: United States Environmental Protection Agency. http://www.epa.gov/ttn/chief/efdocs/lks95_ch.pdf (24 Oct. 2002).
- United States Environmental Protection Agency (USEPA). 1998. *AP-42 emission factors for municipal solid waste landfills – Supplement E, November 1998*. Washington, DC: United States Environmental Protection Agency. <http://www.epa.gov/ttn/chief/ap42/ch02/final/c02s04.pdf> (26 Nov. 2001).
- United States Environmental Protection Agency (USEPA). 2001. *AP-42 emission factors for wood residue combustion in boilers – Supplement G, July 2001*. Washington, DC: United States Environmental Protection Agency. <http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s06.pdf> (26 Nov. 2001).
- Winjum, J.K., Brown, S., and Schlamadinger, B. 1998. Forest harvests and wood products: sources and sinks of atmospheric carbon dioxide. *Forest Science* 44(2):274.
- World Resources Institute (WRI) and World Business Council for Sustainable Development. 2001a. *The greenhouse gas protocol: A corporate accounting and reporting standard*. Washington, DC: World Resources Institute. <http://www.ghgprotocol.org/standard/ghg.pdf> (26 Nov. 2001).
- World Resources Institute (WRI) and World Business Council for Sustainable Development. 2001b. *Calculating CO₂ emissions from the combustion of standard fuels and from electricity/steam purchase - Guide to calculation worksheets*. Washington, DC: World Resources Institute. <http://www.ghgprotocol.org/standard/stationarycombustion.doc> (26 Nov. 2001).
- World Resources Institute (WRI) and World Business Council for Sustainable Development. 2001c. *Calculating CO₂ emissions from the combustion of standard fuels and from electricity/steam purchase - Calculation worksheets*. Washington, DC: World Resources Institute. <http://www.ghgprotocol.org/standard/stationarycombustion.xls> (26 Nov. 2001).
- World Resources Institute (WRI) and World Business Council for Sustainable Development. 2001d. *Calculating CO₂ emissions from mobile sources -Guide to calculation worksheets*. Washington, DC: World Resources Institute. <http://www.ghgprotocol.org/standard/mobile.doc> (26 Nov. 2001).

ANNEX A

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

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

1.1 Carbon Dioxide

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

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

Simply put, Tier 1 methods use emission factors that vary by fuel type only. Tier 2 methods use emissions factors that vary by fuel and by type of combustion unit. Tier 3 methods use emission factors that are based on a measure of activity other than fuel consumption (e.g., per kilometer traveled).

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

IPCC’s Tier 1 approach for estimating CO₂ emissions from fossil fuel combustion uses emission factors that vary by fuel. To reduce the uncertainty caused by using generic information on the carbon contents of fossil fuels, IPCC prefers that the factors be expressed as mass of carbon dioxide per unit of energy – e.g., tons carbon dioxide per terajoule of fossil

fuel burned. IPCC explains that “expressing the carbon emissions factor as the carbon content per unit of energy released reduces [the] variation because of the close link between the carbon content and energy value of the fuel.” In this report, unless shown otherwise, fossil fuel energy content is always expressed as the net calorific value (NCV) of the fuel, also known as the lower heating value (LHV).

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

Table 1. IPCC Default Emission Factors for Fossil Fuels (after IPCC 1997b)
Converted from IPCC’s factors, which are expressed in units of carbon rather than carbon dioxide

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

* assuming no unburned carbon

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

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

$$\text{Tons Carbon /TJ} = 13.708 + (0.0828 \times 10^{-3}) \times (H_V \text{ in kJ/m}^3 - 37.234) \quad (\text{Eq.1})$$

$$\text{Tons CO}_2 \text{ /TJ} = \text{Tons Carbon/TJ} \times 44/12$$

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

$$\text{Tons Carbon /TJ} = 32.15 - (0.234 \times H_V \text{ in TJ/kiloton, dry mineral free basis}) \quad (\text{Eq.2})$$

$$\text{Tons CO}_2 \text{ /TJ} = \text{Tons Carbon/TJ} \times 44/12$$

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

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

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

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

- Pulverized Coal – 1.6%
- Traveling Grate Stoker – 2.7 to 5.4%
- Underfeed Stoker – 4.0 to 6.6%
- Shallow Bed Advanced Fluidized Bed Boiler – Up to 4.0%
- Pressurized or Circulating Fluidized Bed Combustion – 3.0%

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

1.2 Methane

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

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

The Tier 2 factors are presented in two pieces – an uncontrolled emissions factor coupled with a factor to reflect the effectiveness of various emission control devices. The uncontrolled emissions factors are different for utility and industrial boilers. The uncontrolled methane emission factors for industrial boilers are shown in Table 1-16 of the IPCC Reference Manual. Table 1-17 lists methane emission factors for several industrial processes involving fossil fuel combustion, including “lime kilns.” The factors for lime kilns are intended for commercial lime kilns and may or may not be appropriate for kraft mill lime kilns. The Tables are reproduced below. They also contain the emission factors for nitrous oxide, discussed in more detail below. The industrial boiler and kiln emission controls performance for methane is listed in the Reference Manual (Tables 1-21 and 1-22) as being negligible, so the uncontrolled emissions in Tables 1-16 and 1-17 can be considered equal to final controlled emissions (IPCC 1997c).

1.3 Nitrous Oxide

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

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

Table 2. IPCC Industrial Boiler Uncontrolled Emission Factors
(IPCC 1997c, Table 1-16)

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

Note: NAV means Not Available

Table 3. IPCC Uncontrolled Emission Factors for Commercial Lime Kilns
(IPCC 1997c, Table 1-17)

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

2.0 AUSTRALIA – NATIONAL GREENHOUSE GAS INVENTORY and GREENHOUSE CHALLENGE WORKBOOK (Australian Greenhouse Office 1998, 1999, 2001a, 2001b)

There are a number of documents that provide helpful information on the approaches used in Australia to develop estimates of GHG releases from pulp and paper mills. Some of these documents include:

- Greenhouse Challenge Factors and Methods Workbook Version 3 (December 2001) (the GCP Workbook) (AGO 2001b)
- National Greenhouse Gas Inventory (NGGI) Committee Workbook 1.1 for Fuel Combustion Activities (Stationary Sources) (AGO 1998, 1999)
- APIC Environmental Performance Indicators (APIC 2002) (Contains information on industry emissions)

Australia's Greenhouse Challenge contains guidance for company-level reporting which is more relevant for purposes of this report than national-level reporting. The following material, therefore, is drawn largely from the tools issued by the Australian Greenhouse Office for the Greenhouse Challenge program (AGO 2001b). Information on the methods used to develop Australia's national inventory are also available (AGO 2001a)

2.1 Carbon Dioxide

The Australian Greenhouse Office (AGO) Greenhouse Challenge Factors and Methods Workbook contains emission factors for a variety of fossil fuels. Usually, two sets of factors are shown – one for emissions from combustion, and another (full fuel cycle emission factors) that also includes emissions from upstream operations (e.g., mining and fuel processing). There is no mention in the workbook about correcting for unburned carbon, so it is assumed that the emission factors have been adjusted to reflect this. In many cases, the emission factors are for CO₂ only but AGO indicates that “they can be used as CO₂-equivalent emission factors except for equipment with high CH₄ or N₂O emissions – notably internal combustion engines, wood-fueled boilers and bagasse boilers.” A number of the AGO Greenhouse Challenge workbook factors are shown in the Table 4 (AGO 2001b).

The Australian Paper Industry Council (formerly the Pulp and Paper Manufacturers Federation of Australia) issues guidance for estimating greenhouse gas emission which is based on Australia's Greenhouse Challenge program (PPMFA 2001). The CO₂ emission factors used by APIC in 2001 are in Table 5 below.

Table 4. Australian Emission Factors for CO₂ from Stationary Fuel Combustion
(Australian Greenhouse Office 2001b)

Fuel	Direct combustion emissions * kg CO ₂ /GJ ^φ	Full fuel cycle emissions ^θ kg CO ₂ -equiv./GJ ^φ
Black coal	90	NSW 96.0 Queensland 91.6
Brown coal	93	93.9
Brown Coal Briquettes	105	109.4
Coke	119.5	133.3
LPG: non transport	59.4	68.6
Kerosene	69.7	78.9
Heating Oil	69.7	78.9
Automotive diesel: non-transport	69.7	78.9
Industrial/marine diesel fuel	69.7	78.9
Fuel oil	73.6	82.8
Natural Gas (large users)	NSW & ACT 51.7 Victoria 51.6 Queensland 53.0 SA 51.6 WA 53.1 NT 51.7 Australia Ave. 52.2	NSW & ACT 70.7 Victoria 63.4 Queensland 66.2 SA 72.0 WA 59.3 NT 53.2 Australia Ave. 64.0
Waste Methane	51	56.0 (if used in internal combustion engine)
Wood and wood waste	94.0 (d)	95.4 (if used in boiler)
Bagasse	96.8 (d)	98.2 (if used in boiler)

* The AGO indicates that these emission factors are for CO₂ only but “they can be used as CO₂-equivalent emission factors except for equipment with high CH₄ or N₂O emissions – notably internal combustion engines, wood-fuelled boilers and bagasse boilers.”

^φ Energy is expressed in Gross Calorific Value (High Heating Value)

^θ Full Fuel Cycle emissions include upstream emissions from fuel production, transportation etc.

Table 5. Emission Factors from the Pulp and Paper Manufacturers Federation of Australia (PPMFA 2001) - Based on the Australia Greenhouse Challenge factors, but in different units than shown in the table above

Fuel or Process	Unit of Energy or Fuel	Full Fuel Cycle Emission Factors ^θ - Tons CO ₂ -equiv. per unit of energy or fuel
Electricity	kWh	Site Specific
Natural gas	GJ	Site Specific
LPG (non-transport)	t	3.4026
Petroleum products		
LPG transport	kilolitres	1.8633
Aviation gasoline	kilolitres	2.6977
Petrol	kilolitres	2.8933
Automotive diesel oil	kL	3.1806
Industrial/marine diesel fuel	kL	3.2630
Natural gas/CNG	kL	2.3582
Coal	t	Site Specific

^θ Full Fuel Cycle emissions include upstream emissions from fuel production, transportation etc.

2.2 Methane and Nitrous Oxide

Although in many cases, the combustion emission factors shown in Table 4 are for CO₂ only, AGO indicates that “they can be used as CO₂-equivalent emission factors except for equipment with high CH₄ or N₂O emissions – notably internal combustion engines, wood-fueled boilers and bagasse boilers.” These other sources are dealt with elsewhere. The Full Fuel Cycle emission factors in the tables above include CO₂, methane, and nitrous oxide (AGO 2001b).

3.0 CHILE – FIRST NATIONAL COMMUNICATION TO THE CONFERENCE OF THE PARTIES OF THE CONVENTION, OCTOBER 1999 (Chilean National Environmental Commission 1999)

3.1 Carbon Dioxide

The 1999 National Communication indicates that “[t]he methodology used corresponds to the Guidelines set forth by the IPCC and includes the changes introduced in 1996. The emission coefficients used to calculate emissions were those default values proposed by the IPCC for use when no coefficients were available that reflected the conditions in the country.” The report goes on to say that “CO₂ emissions were calculated two ways. The first method uses the Reference Approach, which is based on determining the apparent consumption of each fuel and calculating the corresponding CO₂ emissions through

representative emission factors for each fuel, linked to the technology of the final user. The second method is the final Use Approach, which is based on fuel consumption for each final use and calculating CO₂ emissions through the representative emission factors for each fuel, linked to the technology of the final user.” Accordingly, the methods used in Chile appear to be a combination of IPCC Tier 1 and Tier 2 methods combined with default emission factors (Chilean National Environmental Commission 1999).

3.2 Methane and Nitrous Oxide

The report indicates that for non-CO₂ gases, the Final Use Approach and default emission factors are used, as recommended by the IPCC. Thus, it appears that IPCC’s Tier 2 method with default emission factors was used for methane and nitrous oxide. The report does not list the emission factors used. In the summary tables, there are no methane or nitrous oxide emissions shown for the pulp and paper sector. (Chilean National Environmental Commission 1999)

4.0 FINLAND – ANNEX B OF “GREENHOUSE GAS EMISSIONS AND REMOVALS IN FINLAND” (Technical Research Center of Finland 2001)

4.1 Carbon Dioxide

The Finnish report describes the methods as being consistent with the IPCC Tier 2 approach. The emission factors as shown in the following table. Many of these factors are identical to those used by IPCC but a number are from sources more appropriate to the situation in Finland. The corrections for unoxidized carbon that are used to develop the Finnish inventory are the same as the IPCC Tier 1 factors; i.e., 2% for coal, 1% for oil and oil products, 1% for peat, and 0.5% for gas.

Table 6. CO₂ Emission Factors for Fuel Combustion
(From Technical Research Center of Finland 2001, Table B-1)

Fuel	ton CO ₂ /TJ
Gasoline	73.5
Diesel	74.5
Light Fuel Oil	74.1
Residual Fuel Oil	77.4
Kerosene	73.5
Naphtha	72
LPG	63.1
Waste Oil	77.4
Hard Coal	94.6
Coke	108
Anthracite and Briquettes	94.6
Natural Gas	56.1
Peat	106

4.2 Methane

Finland's report to UNFCCC indicates that "CH₄ and N₂O emission factors are based on mainly national research (included evaluation and application of international research and measurement data)... IPCC default values are used to a lesser degree." The emission factors given in the Annexes to the report, however, are only for small units (less than 1 MW) (Technical Research Center of Finland 2001).

4.3 Nitrous Oxide

Finland's report to UNFCCC indicates that "CH₄ and N₂O emission factors are based on mainly national research (included evaluation and application of international research and measurement data)... IPCC default values are used to a lesser degree." The emission factors given in the Annexes to the report, however, are only for small units (less than 1 MW) (Technical Research Center of Finland 2001).

The Finland report also indicates that "indirect emissions due to atmospheric deposition of NH₃ and NO_x emissions...are calculated...for energy-related and industrial NO_x emissions using the IPCC methodology and default emission factor (0.01 kg N₂O-N/kg NO_x-N emitted). The indirect N₂O emissions caused by nitrogen deposition due to NO_x emissions in the energy sector are included in the emission estimates for the relevant sectors" (Technical Research Center of Finland 2001). This does not appear to be required by the IPCC estimation methods for energy production, although it is mentioned in the IPCC's methods for estimating GHG releases from agriculture. (See Section 4.5.4.A and Table 4-23 in IPCC 1997c.)

5.0 CANADA – "GREENHOUSE GAS ACTION PLAN GUIDELINES – 2001" (FPAC 2001) AND "CANADA'S GREENHOUSE GAS INVENTORY, 1997 EMISSIONS AND REMOVALS WITH TRENDS" (Environment Canada 1999)

5.1 Carbon Dioxide

The Forest Products Association of Canada (FPAC) Guidelines are intended to facilitate forest company participation in the Voluntary Challenge and Registry Program (VCR) for GHGs and the Canadian Industry Program for Energy Conservation/Industrial Energy Innovators (CIPEC/IEI) for energy conservation, as well as several Provincial programs. The method for estimating CO₂ emissions from stationary fossil fuel combustion is generally comparable to IPCC's Tier 1 sectoral approach although the FPAC and VCR guidelines offer no emission factors for coal. Instead the user is instructed to estimate emissions based on the carbon content of the coal being burned. The emission factors, which are published in Appendix A of the FPAC Guidelines, are shown below (FPCA 2001). Like the factors used to develop Canada's inventory, the emission factors published by FPAC are normalized to the volume or weight of fuel rather than heat content.

The Canadian Inventory document contains CO₂ emission factors for coal that vary by type of coal and region of the country. There is no correction factor applied for unoxidized carbon, this having apparently been incorporated into the emission factors.

5.2 Methane

Methods for estimating methane emissions from fossil fuel combustion are comparable to IPCC's Tier 1 methods except that (a) the emission factors are mass- or volume-based rather than energy-based, and (b) there is no discussion of a correction for the effectiveness of control devices (an unimportant difference since IPCC assumes zero percent removal of methane).

5.3 Nitrous Oxide

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

Table 7. Emission Factors from Appendix A of FPAC 2001

Fuel	CO ₂	CH ₄	N ₂ O
Natural Gas	1,880 g/m ³	0.048 g/m ³	0.02 g/m ³
Light (distillate) oil	2,830 g/l	0.006 g/l	0.013 g/l
Heavy (residual) oil	3,090 g/l	0.12 g/l	0.013 g/l
Coal (conventional industrial boiler)	Use carbon content of coal to determine	0.015 g/kg	0.11 g/kg
Coal (fluidized bed)	Use carbon content of coal to determine	0.015 g/kg	2.11 g/kg
Propane Heaters	1,530 g/l	0.03 g/l	-
Diesel Motors (stationary)	2,730 g/l	0.26 g/l	0.40 g/l

6.0 FRANCE – “INVENTAIRE DES ÉMISSIONS DE GAZ À EFFET DE SERRE EN FRANCE DE 1990 À 1999” [INVENTORY OF GREENHOUSE GAS EMISSIONS IN FRANCE FOR THE PERIODE 1990-1999] (CITEPA 2000)

6.1 Carbon Dioxide

The French government starts with CORINAIR methods (EEA 1999) to develop a more detailed inventory than required by UNFCCC and then consolidates the results into sector-level and national reports in the UNFCCC Common Reporting Framework. The IPCC 1996 Revised Guidelines are largely harmonized with CORINAIR's.

Carbon dioxide emissions are estimated using source measurements if available. If not, an approach similar to IPCC's Tier 2 approach is used. National emissions are also estimated using IPCC's Tier 1 approach and the results compared to those resulting from the combined Tier 2 results. The emission factors for fossil fuels are shown the table below.

6.2 Methane and Nitrous Oxide

Site specific measurements are used where available. In the absence of measured data, emission factors are used, many of which reflect the situation in France. The emission factors for CH₄ and N₂O are not included in the report.

Table 8. French Emission Factors for CO₂ from Fossil Fuels
from CITEPA 2000

Fuel	tons CO ₂ / TJ
coking coal or thermal coal	95
sub-bituminous coal	96
lignite	100
coke	107
coke from lignite	108
petroleum coke	96
heavy fuel	78 + / - 1 according to quality
gas oil	75
kerosene and jet fuel	74
gasoline	73
natural gas	57
LPG	64
refinery gas	56
coke oven gas	47
blast furnace gas	268

7.0 JAPAN – INFORMATION FROM THE JAPAN PAPER ASSOCIATION (JPA 2001)

7.1 Carbon dioxide, methane, and nitrous oxide

In Japan, the members of the industry group Keidanren or the Federation of Economic Organization have committed to voluntary reductions in GHG emissions. The information for the Japanese pulp and paper industry is collected and submitted to Keidanren by the Japan Paper Association. Only CO₂ is included in the reporting, not CH₄ and N₂O.

The Japan Ministry of Environment also has a program wherein the GHG emissions for the country are estimated annually. This program includes CO₂ (not including biomass) and N₂O. The emission factors shown below are from the Ministry of Environment program.

Table 9. Japan Ministry of the Environment Emission Factors for Fossil Fuels

Combustion Unit	Fuel	CO ₂	N ₂ O
Boiler	Crude Oil	2.65 kg/litre	0.00000052 kg/litre
Boiler	Kerosene	2.51 kg/litre	
Boiler	Light Oil	2.64 kg/litre	-
Boiler	Heavy Fuel Oil	2.96 kg/litre	0.00000056 kg/litre
Boiler	Coal	2.37 kg/kg	0.00012 kg/kg
Boiler	Petroleum Coke	3.3 kg/kg	0.00013 kg/kg
Boiler	Town Gas	2.15 kg/kg	-
Turbine	Crude Oil	2.65 kg/litre	0.0000011 kg/litre
Turbine	Kerosene	2.51 kg/litre	0.000001 kg/litre
Turbine	Light Oil	2.64 kg/litre	0.0000011 kg/litre
Turbine	LPG	3.02 kg/kg	0.0000014 kg/kg
Turbine	LNG	2.79 kg/kg	0.0000015 kg/kg
Turbine	Town Gas	2.15 kg/kg	0.0000013 kg/m ³
Diesel engine	Crude Oil	2.65 kg/litre	0.000062 kg/litre
Diesel engine	Kerosene	2.51 kg/litre	0.000062 kg/litre
Diesel engine	Light Oil	2.64 kg/litre	0.000062 kg/litre

8.0 SWEDEN – SWEDEN’S NATIONAL INVENTORY REPORT (Swedish Environmental Protection Agency 2001)

8.1 Carbon Dioxide

In its annual report to the UNFCCC, the methods used by Sweden in reporting CO₂ emissions from steam and power generation are essentially Tier 1 IPCC 1996 methods. The CO₂ emission factors used by Sweden are found in Table 1.7.2 of “Sweden’s National Inventory Report 2001” and the emission factors for the fuels of potential interest to pulp and paper are shown below.

Table 10. Swedish Emission Factors for CO₂ from Fossil Fuels
From Table 1.7.2 in Swedish Environmental Protection Agency 2001

Fuel	Emission factor, g CO ₂ /MJ
Gas oil and diesel oil	75.3
Residual fuel oil	76.2
Liquefied petroleum gas	65.1
Natural gas	56.5
Coke oven coke	103.0
Peat (industry consumption)	97.1
Gasoline	72.6
Other kerosene	73.1

8.2 Methane

Sweden uses an IPCC Tier 1 approach for estimating methane emissions. The emission factors are contained in Table 1.7.3 of its 2001 Inventory Report. The table is reproduced below.

Table 11. Swedish Emission Factors for CH₄ from Fossil Fuels
From Table 1.7.3 in Swedish Environmental Protection Agency 2001

Fuel	Emission factor, g CH ₄ /MJ
Gas oil and diesel oil	0.001
Residual fuel oil	0.002
Liquefied petroleum gas	0.001
Natural gas	0.001
Coke oven coke	0.002
Peat (industry consumption)	0.03

8.3 Nitrous Oxide

Like CO₂ and methane, Sweden uses an IPCC Tier 1 approach for estimating nitrous oxide emissions from fossil fuel fired units producing steam and/or power. The emission factors are in Table 1.7.4 of its 2001 inventory. The table is reproduced below. The factors are not identified as being uncontrolled, so it is assumed that they reflect actual (i.e., controlled) emissions.

Table 12. Swedish Emission Factors for N₂O from Fossil Fuels
From Table 1.7.4 in Swedish Environmental Protection Agency 2001

Fuel	Emission factor, g N ₂ O/MJ
Gas oil and diesel oil	0.002
Residual fuel oil	0.005
Liquefied petroleum gas	0.002
Natural gas	0.002
Coke oven coke	0.02
Peat (industry consumption)	0.01

9.0 UNITED KINGDOM – UK GREENHOUSE GAS INVENTORY, 1990 – 1999 (AEA Technology 2001)

9.1 Carbon Dioxide

The UK approach differs from the IPCC Tier 1 approach in several respects. First, the emission factors for solid and liquid fuels are based on mass of fuel rather than energy content. Second, the emission factors for gaseous fuels are based on gross calorific value (GCV) rather than net calorific value (NCV). Third, the emission factors incorporate the impact of unoxidized carbon, so no correction is needed. Finally, the UK approach has different emission factors for a single fuel used in different sectors of the economy (AEA Technology 2001).

The emission factors used by the UK in developing its inventory are included in Tables 1 to 4 of Appendix 2 to “UK Greenhouse Gas Inventory, 1990-1999.” These tables are reproduced below (AEA Technology 2001).

9.2 Methane

The differences between IPCC’s Tier 1 approach and the UK approach for estimating CO₂ emissions are described above. These differences also hold true for estimation of methane from fossil fuel combustion in steam and power generation. It appears that the emission factors represent final emissions (i.e., following control technologies). The emission factors used by the UK in developing its inventory are included in Tables 1 to 4 of Appendix 2 to “UK Greenhouse Gas Inventory, 1990-1999.” The emission factors from these tables are shown below (AEA Technology 2001).

9.3 Nitrous Oxide

The differences between IPCC’s Tier 1 approach and the UK approach for estimating CO₂ emissions are described above. These differences also hold true for estimation of nitrous oxide from fossil fuel combustion in steam and power generation. It appears that the UK emission factors represent final emissions (i.e., following control technologies). From a practical standpoint, this differs from the IPCC approach only to the extent that IPCC provides a separate factor to correct uncontrolled emissions of nitrous oxide from gas boilers

equipped with selective catalytic reduction. The emission factors used by the UK in developing its inventory are included in Tables 1 to 4 of Appendix 2 to “UK Greenhouse Gas Inventory, 1990-1999.” The emission factors from the tables are shown below (AEA Technology 2001).

Table 13. UK Emission Factors
From Tables 1 through 4 of Appendix 2 of AEA Technology 2001

Fuel	Source	CH ₄ Emissions		N ₂ O Emissions	
Burning Oil	Misc. Sources	0.0432	kg/t	0.0265	kg/t
Gas Oil	Agriculture	0.225	kg/t	0.026	kg/t
Gas Oil	Industry (General)	0.0432	kg/t	0.026	kg/t
Fuel Oil	Industry (General)	0.122	kg/t	0.0243	kg/t
Coal	Industry (General)	0.011	kg/t	0.213	kg/t
Coal	Autogenerators	0.02	kg/t	0.0658	kg/t
Coke	Industry (General)	0.011	kg/t	0.221	kg/t
Solid Smokeless Fuel (SSF)	Industry (General)	0.011	kg/t	0.218	kg/t
LPG	Industry (General)	0.0971	g/therm*	0.0095	g/therm*
Natural Gas	Industry (General)	0.38	g/therm*	0.0095	g/therm*
Natural Gas	Autogenerators	0.579	g/therm*	0.351	g/therm*

* Based on Gross Calorific Value

10.0 UNITED STATES – INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990-1999 (USEPA 2001a)

10.1 Carbon Dioxide

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

Another departure from the default IPCC Tier 1 approach regards the unoxidized carbon in coal burning – US EPA uses 1% rather than the 2% default value suggested by IPCC.

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

Table 14. US EPA CO₂ Emission Factors for Fossil Fuels
From Table A-13 from Annex A of USEPA 2001a
(Heat content in Gross Calorific Value)

Fuel Type	Tg C/QBtu HHV	Tg CO ₂ /QBtu HHV
Industrial Other Coal*	25.63	93.98
Coke Imports	27.85	102.12
Utility Coal*	25.76	94.45
Natural Gas	14.47	53.06
Distillate Fuel Oil	19.95	73.15
Kerosene	19.72	72.31
LPG*	16.99	62.30
LPG (energy use)*	17.11	62.74
LPG (non-energy use)*	16.88	61.89
Motor Gasoline*	19.36	70.99
Residual Fuel	21.49	78.80

* EPA indicates these vary from year to year. The values shown are for 1999.

10.2 Methane

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

10.3 Nitrous Oxide

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

11.0 WRI/WBCSD – THE GREENHOUSE GAS PROTOCOL AND SUPPORTING GUIDANCE (WRI 2001a, 2001b, 2001c)

11.1 Carbon Dioxide

WRI/WBCSD recommends that site-specific information on fuel use and fuel carbon content (if available) be used to estimate CO₂ emissions from stationary combustion sources. If site specific data on fuel carbon content are unavailable, the WRI/WBCSD guidance material contains a large number of emission factors from other sources. Some of the ones of potential interest to pulp and paper mills are shown in the following tables. The guidance indicates that WRI/WBCSD protocol does not require a correction for unoxidized carbon but notes that this may not be accurate for small coal fired units (WRI 2001b, 2001c).

11.2 Methane and Nitrous Oxide

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

Table 15. WRI/WBCSD CO₂ Emission Factors for Stationary Combustion, October 2001 (WRI 2001c)

Fuel type	kg CO ₂ / GJ fuel LHV	kg CO ₂ / million btu fuel LHV	kg CO ₂ / million btu fuel LHV	kg CO ₂ / GJ fuel HHV	kg CO ₂ / million btu fuel HHV	kg CO ₂ / MWh fuel HHV	kg CO ₂ / metric tons fuel	kg CO ₂ / short tons fuel	kg CO ₂ / litres fuel	kg CO ₂ / gallons fuel	kg CO ₂ / standard cubic meters	kg CO ₂ / 1000 SCF
Distillate fuel (No. 1, No. 2, No. 4 fuel oil and diesel)	74.01	78.08	266.41	69.38	73.20	249.83	3142 (UK DETR)	2850 (UK DETR)	2.68	10.15		
Residual fuel oil (No. 5, No. 6 fuel oil)	77.30	81.55	278.26	74.77	78.88	269.22	3117 (UK DETR)	2828 (UK DETR)	3.12	11.81		
LPG	63.20	66.68	227.50	59.78	63.07	215.26			1.54	5.81		
Propane	62.99 (EIA)	66.45 (EIA)	226.8 (EIA)	59.84	63.13	215.46			1.52	5.75		
Natural gas (dry)	56.06	59.14	201.80	50.34	53.11	181.26					1.93	54.70
Anthracite	98.30	103.70	353.85	97.77	103.15	352.05	1926.04	1747.30				
Bituminous coal	94.53	99.73	340.28	88.27	93.12	317.82	2465.61	2236.80				
Sub-bituminous coal	96.00	101.28	345.57	91.45	96.48	329.28	1857.91	1685.50				
Lignite	101.12	106.68	364.00	92.61	97.70	333.45	1395.83	1266.30				
Peat	105.89	111.71	381.26	100.6 (IPCC)	106.12 (IPCC)	362.2 (IPCC)						
Petroleum coke	100.76	106.30	362.71	96.80	102.12	348.53	3384.37	3070.30	3.88	14.69		
Coke oven / gas coke	108.09	114.03	389.18	102.68 (IPCC)	108.33 (IPCC)	369.72 (IPCC)						
Sludges	79.90	84.29	287.68	75.90	80.08	273.30						
Pitch	79.90	84.29	287.68	75.90	80.08	273.30						
Saw dust impregnated	75.10	79.23	256.31	71.34	75.27	243.49						
Tires and tire derived fuel	85.78	90.49	308.86	81.49	85.97	293.41	3080.03	2794.20				
Wood and wood waste	100.44 (EIA)	105.97 (EIA)	361.67 (EIA)	95.42	100.67	343.58	1906.97	1730.00				
Sources:	<p>Emission factors based on higher heating values from EIA, 2001, Appendix B, if not otherwise indicated</p> <p>Emission factors based on lower heating values from IPCC, 1999, Volume 2, Section 1, if not otherwise indicated</p> <p>Emission factors based on volumetric or mass units from EIA, 2001, Appendix B, if not otherwise indicated</p> <p>Other sources used:</p> <p>DETR, 1999, Section 4.2 (DETR factors are specifically labeled in the table)</p> <p>Holderbank, 2000 (Holderbank factors are in italics)</p> <p>For fuels not covered by IPCC, emission factors were calculated based on EIA values using the following formula:</p> <p>Emission factor (LHV) = Emission factor (HHV) / 0.95 for solid/liquid fuels and</p> <p>Emission factor (LHV) = Emission factor (HHV) / 0.90 for gaseous fuels</p> <p>For fuels not covered by EIA, emission factors were calculated based on IPCC values using the same conversion factor between lower and higher heating values</p>											

ANNEX B

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, this section contains a discussion of the correct approach for estimating these emissions. The correct approach is to include only CO₂ emissions associated with the fossil fuels burned in the kiln or calciner, and CH₄ and N₂O emissions if deemed material to the inventory.

1.0 EXISTING PROTOCOLS

Environment Canada, in “Canada’s Greenhouse Gas Inventory, 1997 Emissions and Removals with Trends,” (page 41) states that “[e]missions from the regeneration of lime from spent pulping liquors at pulp mills are not included in the inventory. Since this CO₂ is biogenic in origin, it is recorded as a change in forest stock in the ‘Land Use Change and Forestry’ category” (Environment Canada 1999).

FPAC reiterates this position in its “2001 Greenhouse Gas Action Plan Guidelines” (page 11) where it states that “...emissions from the regeneration of lime from spent pulping liquors at pulp mills should not be reported, as this CO₂ is biogenic in origin” (FPAC 2001).

IPCC appears to imply that CO₂ emissions from kraft mill lime kilns and calciners should be included 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, page 3.23). The question of whether CO₂ should be included, however, is not directly addressed. IPCC suggests emission factors of 1.0 and 1.1 kg CH₄/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 appears to be uncertain about the situation. In “U.S. Greenhouse Gas Emissions and Sinks: 1990-1999” (page 3-8) EPA states that “[i]n the paper industry, mills that employ the sulfate process (i.e., Kraft) consume lime in order to causticize a waste sodium carbonate solution (i.e., black liquor). Most sulfate mills recover the waste calcium carbonate after the causticizing operation and calcine it back into lime -thereby generating CO₂ -for reuse in the pulping process. However, some of these mills capture the CO₂ released in this process to be used as precipitated calcium carbonate (PCC). Further research is necessary to determine to what extent CO₂ is released to the atmosphere through generation of lime by paper mills” (USEPA 2001a).

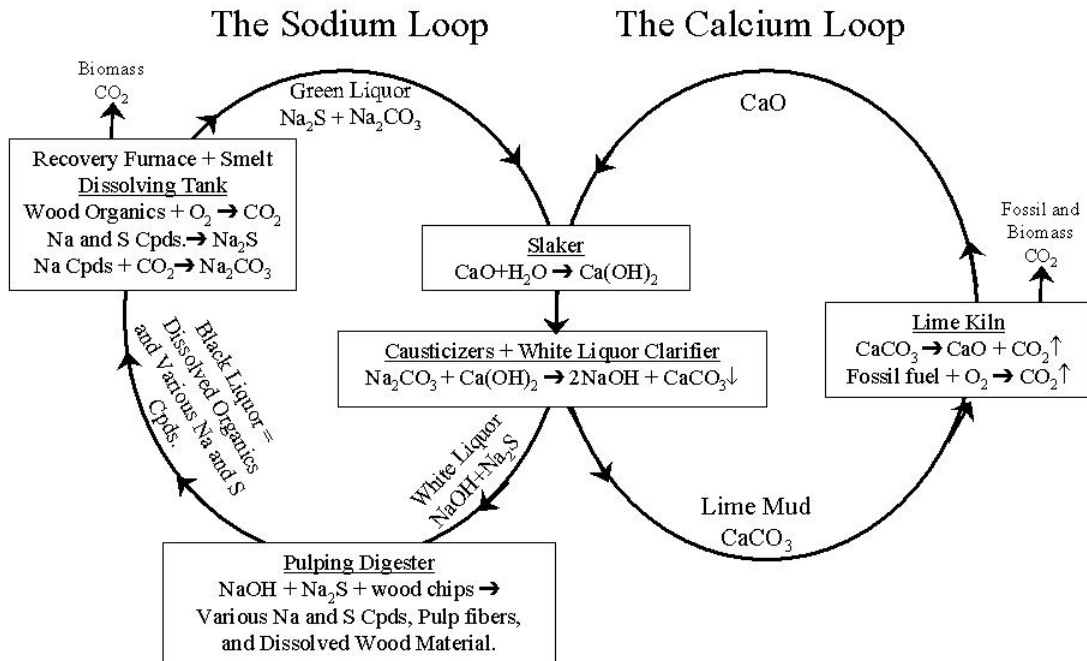
2.0 CORRECTLY ACCOUNTING FOR GREENHOUSE GAS EMISSIONS FROM KRAFT MILL LIME KILNS AND CALCINERS

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 1. 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. The pulping 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 1. 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 CO₂, 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 (CaCO₃) 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 CO₂ 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 CO₂ 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 CaCO₃ is added to the recovery system as a make-up chemical, the only CO₂ 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 as high as 34 ppm were measured (NCASI 1981). 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 CH₄/TJ.

IPCC suggests emission factors of 1.0 and 1.1 kg CH₄/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 CH₄/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 CO₂. IPCC has reviewed the literature and has 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 N₂O generation, but data are lacking (Hough 1985).

It is reasonable, therefore, to assume that N₂O 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 N₂O 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 CO₂ (or gas from another boiler) to manufacture precipitated calcium carbonate (PCC) at satellite plants. The PCC manufacturing process involves the reaction of CO₂-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 CO₂ content.

While the amounts of CO₂ 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 CO₂ 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 CO₂ captured in PCC manufacture can actually exceed the amounts of fossil CO₂ emitted by the mill.

Because the CO₂ exported to PCC plants is not emitted by the mill, nor by any source owned by the company, this CO₂ is reported as an export rather than an emission. Where CO₂ is exported from lime kilns, the gas consists of a combination of fossil fuel-derived CO₂ and climate-neutral biomass-derived CO₂. In the suggested reporting format for the calculation tools, these two types of CO₂ exports are reported separately. The data on exports of fossil fuel-derived CO₂ are reported with other data on fossil fuel-derived CO₂ and the exports of biomass-derived CO₂ are covered in the “Supporting Information on Biomass” supplied in Annex I.

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 these 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 C

CH₄ AND N₂O EMISSIONS FROM BIOMASS COMBUSTION – OVERVIEW OF METHODS IN EXISTING PROTOCOLS

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

1.1 Methane

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

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

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

1.2 Nitrous Oxide

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

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

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

2.0 AUSTRALIA (AGO 1998, 1999, 2001a, 2001b)

2.1 Methane and Nitrous Oxide

The Factors and Methods Workbook issued by the Australian Greenhouse Office does not include separate emission factors for methane and nitrous oxide (AGO 2001b). Emission factors for methane and nitrous from industrial wood combustion are published, however, in the Energy Methods Workbooks that explain the methodology used to prepare Australia's national GHG inventories (AGO 1998, 1999, 2001a). These emission factors are 4.2 Mg CH₄ /PJ (GCV) and 4.1 Mg N₂O / PJ (GCV) (AGO 1998, 1999).

3.0 CHILE – FIRST NATIONAL COMMUNICATION TO THE CONFERENCE OF THE PARTIES OF THE CONVENTION, OCTOBER 1999 (Chilean National Environmental Commission 1999)

3.1 Methane and Nitrous Oxide

The report indicates that for non-CO₂ gases, the Final Use Approach and default emission factors are used, as recommended by the IPCC. Thus, it appears that IPCC's Tier 2 method with default emission factors was used for methane and nitrous oxide. The report does not list the emission factors used. In the summary tables, there are no methane or nitrous oxide emissions listed for the pulp and paper sector (Chilean National Environmental Commission 1999).

4.0 FINLAND – ANNEX B OF “GREENHOUSE GAS EMISSIONS AND REMOVALS IN FINLAND” (Technical Research Center of Finland 2001)

4.1 Methane

Finland's report to UNFCCC indicates that “CH₄ and N₂O emission factors are based on mainly national research (included evaluation and application of international research and measurement data)... IPCC default values are used to a lesser degree.” The emission factors given in the Annexes to the report, however, are only for small units (less than 1 MW) (Technical Research Center of Finland 2001).

4.2 Nitrous Oxide

Finland's report to UNFCCC indicates that "CH₄ and N₂O emission factors are based on mainly national research (included evaluation and application of international research and measurement data)... IPCC default values are used to a lesser degree." The emission factors given in the Annexes to the report, however, are only for small units (less than 1 MW) (Technical Research Center of Finland 2001).

The Finland report also indicates that "indirect emissions due to atmospheric deposition of NH₃ and NO_x emissions...are calculated...for energy-related and industrial NO_x emissions using the IPCC methodology and default emission factor (0.01 kg N₂O-N/kg NO_x-N emitted). The indirect N₂O emissions caused by nitrogen deposition due to NO_x emissions in the energy sector are included in the emission estimates for the relevant sectors." This does not appear to be required by the IPCC estimation methods for energy production, although it is mentioned in the IPCC's methods for estimating GHG releases from agriculture (Technical Research Center of Finland 2001). (See Section 4.5.4.A and Table 4-23 in the IPCC Reference Manual.)

5.0 CANADA – "GREENHOUSE GAS ACTION PLAN GUIDELINES – 2001" (FPAC 2001) AND "CANADA'S GREENHOUSE GAS INVENTORY, 1997 EMISSIONS AND REMOVALS WITH TRENDS" (Environment Canada 1999)

5.1 Methane

The method for estimating GHG emissions from biomass fuel combustion is generally comparable to IPCC's Tier 1 sectoral approach except that FPAC (and Environment Canada) biomass emission factors are based on mass of fuel rather than heat content. The emission factors are published in Appendix A of the FPAC Guidelines. The emission factor for methane from wood fuel/wood waste is 0.15 g CH₄/kg fuel (Environment Canada 1999 and FPAC 2001).

In "Canada's Greenhouse Gas Inventory, 1997 Emissions and Removals with Trends," Appendix B1 explains that the emission factors were derived as averages of those available in EPA's AP-42. The AP-42 factors have since changed. See the discussion of the US protocol below for the most recent AP-42 emission factors. There is no emission factor given for spent pulping liquors. Although the guidelines do not indicate whether the factors are based on wet or dry weight of fuel, the emission factor shown for CO₂ from wood fuel/wood waste (1500 g/kg) suggests that the factors are based on dry weight. There is no discussion of the effectiveness of control devices, but it is assumed that the factors are for emissions after control devices. This is an unimportant departure from IPCC methods since IPCC assumes that there is no removal of methane across control devices.

5.2 Nitrous Oxide

Like methane, methods for estimating N₂O emissions from biomass fuel combustion are comparable to IPCC's Tier 1 methods except that (a) the emission factors are mass- or volume-based rather than energy-based, and (b) there is no discussion of a correction for the effectiveness of control devices (an unimportant difference since IPCC provides removal data only for gas fired boilers equipped with selective catalytic reduction). The emission factor for nitrous oxide from wood fuel/wood waste is .016 g N₂O/kg fuel. It is assumed that this emission factor estimates emissions based on dry weight of fuel and after control devices (Environment Canada 1999 and FPAC 2001).

In "Canada's Greenhouse Gas Inventory, 1997 Emissions and Removals with Trends," Appendix B1 explains that the emission factors were derived as averages of those available in EPA's AP-42, which have since changed. See the discussion of the US protocol below for the most recent AP-42 emission factors.

6.0 JAPAN – INFORMATION FROM THE JAPAN PAPER ASSOCIATION (JPA 2001)

6.1 Methane and Nitrous Oxide

Methane and nitrous oxide are not included in the estimates collected by the Japan Paper Association for the Federation of Economic Organization (Keidanren). The Japan Ministry of Environment, however, includes CH₄ and N₂O in its inventories and uses the following emission factors for biomass fuels (JPA 2001).

Table 1. Japan Ministry of the Environment Emission Factors for Biomass Fuels from information provided by the Japan Paper Association (JPA 2001)

Combustion Unit	Fuel	CH ₄	N ₂ O
Boiler	Black Liquor	0.000033 kg/kg dry solids	-
Boiler	Wood	0.00082 kg/kg dry solids	0.000063 kg/kg dry solids
Waste combustion	Sludge from mills at 50% moisture	0.0097 kg/wet ton	0.45 kg/wet ton

7.0 SWEDEN – SWEDEN'S NATIONAL INVENTORY REPORT (Swedish Environmental Protection Agency 2001)

7.1 Methane

Sweden uses an IPCC Tier 1 approach for estimating methane emissions. The emission factors are contained in Table 1.7.3 of its 2001 Inventory Report. The emission factors for methane from wood waste and black liquor combustion are both 30 kg CH₄/TJ, the same as IPCC's Tier 1 default factor (Swedish Environmental Protection Agency 2001).

7.2 Nitrous Oxide

Like CO₂ and methane, Sweden uses an IPCC Tier 1 approach for estimating nitrous oxide emissions from fossil fuel fired units producing steam and/or power. The emission factors are in Table 1.7.4 of its 2001 inventory. The Swedish emission factors for nitrous oxide from wood waste and black liquor combustion are both 5 kg N₂O/TJ, whereas IPCC's Tier 1 default factor is 4 kg N₂O/TJ. The factors are not identified as being uncontrolled, so it is assumed that they reflect actual (i.e., controlled) emissions (Swedish Environmental Protection Agency 2001).

8.0 UNITED KINGDOM – UK GREENHOUSE GAS INVENTORY, 1990 – 1999 (AEA Technology 2001)

8.1 Methane

The UK approach differs from the IPCC Tier 1 approach primarily in that the emission factors for wood fuels are based on mass of fuel rather than energy content. The emission factors used by the UK in developing its inventory are included in Tables 1 to 4 of Appendix 2 to “UK Greenhouse Gas Inventory, 1990-1999.” The emission factor for methane from wood as a fuel in industry is 0.482 kg CH₄/t. Although the table does not indicate whether this is based on wet or dry tons, the emission factor for carbon from wood burning (470 kg/t) suggests that the emission factors are based on dry weight. It is assumed that this factor is for emissions after control devices have been applied (AEA Technology 2001).

8.2 Nitrous Oxide

The UK approach differs from the IPCC Tier 1 approach primarily in that the emission factors for wood fuels are based on mass of fuel rather than energy content. The emission factors used by the UK in developing its inventory are included in Tables 1 to 4 of Appendix 2 to “UK Greenhouse Gas Inventory, 1990-1999.” The emission factor for nitrous oxide from wood as a fuel in industry is 0.069 kg N₂O/t. Although the table does not indicate whether this is based on wet or dry tons, the emission factor for carbon from wood burning (470 kg/t) suggests that the emission factors are based on dry weight. It appears that the UK emission factors represent final emissions (i.e., following control technologies) (AEA Technology 2001).

9.0 UNITED STATES – INVENTORY OF U.S. GREENHOUSE GAS EMISSIONS AND SINKS: 1990-1999 (USEPA 2001a) and AP-42 EMISSIONS FACTORS (USEPA 2001b)

9.1 Methane

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

USEPA’s AP-42 Emission Factors Document (Supplement G, July 2001) indicates that “[m]ethane emissions are highest during periods of low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycle for boilers. Typically, conditions that favor formation of N₂O also favor emissions of CH₄” (USEPA 2001). The emission factor given in Supplement G as the average emission factor for methane from wood residue combustion is 0.021 lb/MMBtu GCV (9.5 kg CH₄/TJ NCV assuming that NCV is 5% less than GCV). There are no data on non-CO₂ GHG emissions from spent liquor combustion in AP-42 (USEPA 2001b).

9.2 Nitrous Oxide

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

USEPA’s AP-42 Emission Factors Document (Supplement G, July 2001) indicates that “[f]ormation of N₂O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N₂O is minimized when combustion temperatures are kept high (above 1475°F) and excess air is kept to a minimum (less than 1 percent)” (USEPA 2001b). In earlier supplements to AP-42, EPA had given separate emission factors for stoker boilers and fluidized boilers based on a theory that fluidized bed boilers generated more N₂O. In the current supplement, this distinction has been eliminated and a single N₂O emission factor is shown for all wood fired boilers. The emission factor given in Supplement G as the average emission factor for nitrous oxide from wood residue combustion is 0.013 lb/MMBtu GCV (5.9kg N₂O/TJ NCV assuming that NCV is 5% less than GCV). There are no data on non-CO₂ GHG emissions from spent liquor combustion in AP-42 (USEPA 2001b)

10.0 WRI/WBCSD – THE GREENHOUSE GAS PROTOCOL AND SUPPORTING GUIDANCE (WRI 2001a, 2001b, 2001c)

10.1 Methane and Nitrous Oxide

The WRI/WBCSD guidance does not include CH₄ and N₂O. In the words of the October 2001 guidance, “a much greater effort is required to estimate CH₄ and N₂O emissions from

stationary sources [compared to CO₂], and a much higher level of uncertainty exists. Consequently, due the relative insignificance of CH₄ and N₂O emissions from most stationary sources, [the WRI/WBCSD protocol] only includes guidance for estimating CO₂ emissions from stationary sources” (WRI 2001b)

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

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

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

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

Perhaps the most ambitious recent study was undertaken in Finland by Fortum Power and Heat Oy with funding from the Finnish Forest Industries Federation and the Finnish Energy Industries Federation. The report “Methane and Nitrous Oxide Emissions in the Finnish Energy Production” was published in May of 2001 and contains new data from 11 boilers and 2 recovery furnaces (Fortum 2001). Of the 11 boilers, six were fluidized bed boilers burning biomass and/or peat, two were pulverized coal-fired boilers, two were combined cycle gas turbine facilities, and one was a heavy oil boiler. In addition, the report summarizes existing emission factors, noting that most of them had been proven to be unreliable.

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

Table 2. Comparison of measured N₂O and CH₄ emissions with other emission factors.

-Parenthesis indicate abnormal process conditions-

Table 14 from Fortum Power and Heat Oy 2001

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

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

11.2 US Data from NCASI

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

Table 3. Data on Methane Emissions from Wood Residue Boilers
Collected in the Late 1970s and Early 1980s Generated by EPA Method 25
Data have been converted from GCV to NCV assuming a 5% difference

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

ANNEX D

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

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

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

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

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

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

Thus, it is clear that IPCC’s method places all energy-related emissions from pulp and paper mills in the pulp and paper sector unless the emissions are from an activity where pulp and paper making is not the primary business. The emissions from boilers making steam, some of which is exported or used to make exported electricity, remain in the pulp and paper sector

unless the boilers are associated with a separate business that just happens to be located on the mill site. Similarly, the emissions from gas turbines on mill sites are attributed to the pulp and paper sector unless, perhaps, the turbines are owned by a separate company whose main business is power generation.

Likewise, emissions from the off-site production of electricity used by pulp and paper mills remain in the energy sector rather than being assigned to the pulp and paper sector.

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

2.0 AUSTRALIA – NATIONAL GREENHOUSE GAS INVENTORY – 1999 (Australian Greenhouse Office 1998, 1999, 2001a, 2001b and PPMFA 2001)

The Pulp and Paper Manufacturers Federation of Australia collects greenhouse gas emissions information in an annual Environmental Performance Indicators survey (PPMFA 2001). The survey form indicates that emission factors for electricity (as well as gas and coal) vary between states. Companies are directed to a Factors and Methodologies Workbook that is published by the government under its Greenhouse Challenge program.

The Factors and methodologies Workbook includes purchased power emission factors for each State. The emission factors include transmission and distribution losses (AGO 2001b). The emission factors are shown below.

Table 1. Australian Emission Factors for Electricity Purchased (AGO 2001b)

State	kg CO ₂ -equiv./kWh*
New South Wales, Australian Capital Territory	0.968
Victoria	1.467
Queensland	1.040
South Australia	1.109
Western Australia	1.032
Tasmania	0.002
Northern Territory	0.756

* Includes transmission and distribution losses

3.0 FINLAND – ANNEX B OF “GREENHOUSE GAS EMISSIONS AND REMOVALS IN FINLAND” (Technical Research Center of Finland 2001)

Finland’s national inventory follows the IPCC practice of allocating emissions to the sector where they are generated. There is no attempt, therefore, to allocate emissions from power producers to industrial consumers of purchased power.

The large amounts of combined heat and power (CHP) production in Finland, however, have prompted that country to use a slightly different approach when deciding in which sector to place power plants that supply a large fraction of their power or steam output to industrial facilities. Annex B indicates that “[i]n Finland many CHP power plants produce electricity and steam to the manufacturing industry, especially to pulp and paper plants. These power plants are usually economically part of the industrial sectors themselves, and in this case, the power plants are regarded as 'autoproducers' according to the IEA definitions. In the Finnish inventory (CRF tables) these autoproducer power plants are allocated to the corresponding industrial sectors. During the last years a growing number of these autoproducer power plants have been sold to the energy companies (i.e., companies, the primary activity of which is to produce and sell electricity and heat to the market). By definition, these plants should be allocated to the Energy Industries sector [under the IPCC protocol]. However, in the Finnish inventories these plants are treated as autoproducers. Also some new power plants which have been built by the energy companies to serve the manufacturing industry have been categorized in the same way in the Finnish inventory. This allocation has been used in cases where there is a direct connection (steam pipe) between the power plant and the industrial plant and the industrial plant uses most of the energy (usually steam) produced by the power plant. The reasoning and justification for this allocation is that it enables linking of the emissions more closely to the actual production processes” (Technical Research Center of Finland 2001).

The Finnish Forest Industries Federation periodically publishes environmental statistics for the Finnish industry (Finnish Forest Industries Federation 2001). This document indicates that the forest industry’s electricity requirement in 2000 was 26.3 billion kilowatt-hours, corresponding to 61% of industry’s and 33% of Finland’s total requirement. Of the 26.3 billion kWh required by the industry, about 11.1 billion kWh was generated “in-house.” The amounts procured from outside were largely from energy producers in which forest industry companies are shareholders. The report contains separate statistics for emissions from purchased power. No details are given in the report regarding how these indirect emissions are calculated for power or steam exports, but the Finnish Forest Industries Federation has provided the following information.

The Finnish Forest Industries Federation asks mills to report only direct emissions. These are the same reports as made to the Finnish authorities. Where estimates of indirect emissions are needed, the Finnish Forest Industries Federation estimates the indirect emissions by using mill data on the amounts of purchased electricity together with information on the fuel mix of the electrical power generation plants supplying the mills. It is unclear what is done in cases where the mill is purchasing steam (instead of, or in addition

to, electricity) from an off-site entity. In cases where mills export electricity, no attempt is made to reduce the mill's reported emissions to reflect the exports. (Karessuo 2001).

4.0 CANADA – “GREENHOUSE GAS ACTION PLAN GUIDELINES – 2001” (FPAC 2001) AND “CANADA’S GREENHOUSE GAS INVENTORY, 1997 EMISSIONS AND REMOVALS WITH TRENDS” (Environment Canada 1999)

FPAC recommends that companies “report indirect emissions that they influence as part of their production process” (FPAC 2001). These are reported separately from direct emissions. Emission factors are supplied to convert purchased electricity into CO₂ emissions. The factors vary Province by Province reflecting the methods and fuels used to generate electricity. These factors, which are also published in the 1999 Voluntary Challenge and Registry (VCR) Guidelines are shown in the following table (VCR 1999).

The FPAC guidelines do not directly address methods for estimating the impacts of electrical power exports from industry facilities.

The special case of power imports or exports from CHP production are not addressed directly in the FPAC guidelines, but the guidelines point out that under the Canadian Baseline Protection Initiative, “parties involved in cogeneration projects may decide between themselves how to share direct reductions” (FPAC 2001)

Table 2. Electric Energy Consumption Indirect Emissions Factors
(Table 5.4 from VCR 1999)

Province	kg CO ₂ equivalents / kWh
Newfoundland and Labrador	0.19
Prince Edward Island	0.546
Nova Scotia	0.78
New Brunswick	0.546
Quebec	0.0014
Ontario	0.18
Manitoba	0.011
Saskatchewan	0.862
Alberta	0.991
British Columbia	0.02
Yukon/Northwest Territories/ Nunavut	GHG emission rates depend on local generation equipment.

5.0 FRANCE – “INVENTAIRE DES ÉMISSIONS DE GAZ À EFFET DE SERRE EN FRANCE DE 1990 À 1999” [INVENTORY OF GREENHOUSE GAS EMISSIONS IN FRANCE FOR THE PERIOD 1990-1999] (CITEPA 2000)

The French national inventory includes a sectoral level analysis, built on the CORINAIR methodology. The report indicates that emissions are assigned to the sector where they are emitted. As an example, the report indicates that there is no emission penalty assigned for using electricity because the emissions are assigned to the entity producing the electricity (CITEPA 2000, Appendix 3, page 13).

The report goes on to say that at facilities that generate their own electricity, the emissions are assigned to the sector representing the principal activity of the facility (e.g., industrial, district heating, etc.) (CITEPA 2000, Appendix 3, page 15).

6.0 JAPAN – INFORMATION FROM THE JAPAN PAPER ASSOCIATION (JPA 2001)

With regards to electricity or steam that is purchased or sold by mills, the Japan Paper Association (JPA) either adds or deducts energy used and/or carbon emissions in the following manner.

For purchased electricity, JPA uses emission factors published by the national organization representing the electrical power producers. For the year 2000, the factors were –

$$1 \text{ kWh} = 9.00 \text{ MJ}$$

$$\text{kWh} = 0.090 \text{ kg Carbon}$$

(Note: The value used by the Ministry of Environment for the pulp and paper industry in 1999 was 0.097 kg Carbon/kWh or 0.357 kg CO₂/kWh)

For purchased steam, the factor is 1 kg steam = 2,675 kJ in fuel. This would be converted into CO₂ emissions by considering the carbon content of the fuel. (Note: The value used by the Ministry of Environment for the pulp and paper industry in 1999 was 0.072 kg CO₂ / MJ steam.)

For electricity sold, mills calculate the emissions associated with the sold power by considering the fuels used to generate the electricity, their carbon contents, and the efficiency of electrical power production. Sold steam is considered in the same way except boiler efficiency is used (rather than the overall efficiency of power production) (JPA 2001).

Where it is necessary to apportion emissions because energy is purchased or sold in more than one form, the emissions are allocated by considering the energy content of the steam or electricity being sold (or purchased) and the overall efficiency associated with its generation. From these values, one can estimate the amount of fuel that was required to generate the specific amount of steam or electricity. The carbon emissions are then calculated from the carbon contents of the fuel (JPA 2001).

7.0 SWEDEN – SWEDEN’S NATIONAL INVENTORY REPORT 2001 AND INFORMATION FROM THE SWEDISH FOREST INDUSTRIES FEDERATION

Sweden’s report contains methods for the national inventory only, and does not discuss the issue of direct versus indirect emissions (Swedish Environmental Protection Agency 2001).

The Swedish Forest Industries Federation reports GHG emissions from the Swedish industry. It estimates indirect emissions based on reported purchases of electricity and emission factors. In cases where a mill sells (or gives away) power or steam, it retains the emissions associated with its generation (Axelsson 2001).

8.0 UNITED KINGDOM – UK GREENHOUSE GAS INVENTORY, 1990 – 1999 (AEA Technology 2001) AND INFORMATION FROM THE PAPER FEDERATION OF GREAT BRITAIN (Barnard 2001)

The UK constructs its inventory from data generated in a number of national programs that must be aligned with the IPCC methodology. Among the adjustments that must be made is the method for handling emissions from autogeneration of electrical power in CHP systems. In the UK inventory, “CHP systems where the electricity is fed into the public supply are classified as power stations and CHP systems where the electricity is used by the generator are classified as autogeneration.” CHP autogenerator emissions are included in the “other industry” sector of the sectoral energy tables in the IPCC Common Reporting Framework (i.e., sector 1A2f) (AIA Technology 2001).

Otherwise, the UK report follows the IPCC convention of assigning the emissions to the sector where they originate. The issue of direct versus indirect emissions is not otherwise dealt with.

The Paper Federation of Great Britain indicates that because its agreement with the government regarding the Climate Change Levy is based on energy efficiency, the question of indirect emissions has not been addressed in this context (Barnard 2001).

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

Although EPA’s US inventory is not intended to allocate emissions at the company- or facility-level, it does attempt to divide national GHG emissions among different sectors of the economy, estimating “combustion” and “electricity” emissions from the industrial, transportation, residential, and commercial sectors. The emissions generated by electrical power producers are “distributed to each end-use sector based upon the sector’s share of

national electricity. ... This method of distributing emissions assumes that each sector consumes electricity generated from an equally carbon-intensive mix of fuels and other energy sources. In reality, sources of electricity vary widely in carbon intensity (e.g., coal versus wind power). By giving equal carbon-intensity weight to each sector's electricity consumption, emissions attributed to one end-use sector may be somewhat overestimated, while emissions attributed to another end-use sector may be slightly underestimated.” (USEPA 2001a, pg. 2-7)

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

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

The Department of Energy has a different set of guidelines that are focused on facility- or company-level reporting. This different focus is due to the fact that the DOE guidelines are for use in a program for reporting voluntary reductions in GHGs at the facility- or company-level (the 1605(b) program). Generally, the guidelines are very flexible because DOE wants to encourage a wide range of GHG reduction activities, some of which may not lend themselves to standard carbon accounting methods. The guidelines specifically allow the reporting of reductions in either direct or indirect emissions, or both (USDOE 2000).

DOE provides guidance for estimating emissions related to purchased power (or reduced use of purchased power). It suggests using emission factors developed by DOE for average electrical power generated in each of the 50 states or case-by-case emission factors derived from information on the fuels used to generate the purchased power. The DOE last updated the state-specific emission factors for electricity in 2000. The factors, and the methodology to estimate them are in “Updated State-level Greenhouse Gas Emission Factors for Electricity Generation” published in March 2001 by the Energy Information Administration (USDOE 2001a). The emission factors from that document are available on the internet and are shown in the following table (USDOE 2001b).

Table 3. 1997-99 US State Average CO₂ Emission Factors for Electric Utilities

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

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

10.0 WRI/WBCSD – THE GREENHOUSE GAS PROTOCOL AND SUPPORTING GUIDANCE (WRI 2001a, 2001b, 2001c)

The WRI/WBCSD Greenhouse Gas Protocol identifies three “scopes” for emissions reporting. Scope one is direct emissions, scope two is indirect emissions from imports of electricity, steam or other heat, and scope three is other indirect emissions. The GHG Protocol recommends that companies account for and report at least scopes 1 and 2.

Emissions associated with the export of electricity or steam are included as “supporting information” and not netted against a facility’s direct emissions. Only CO₂ must be reported (WRI 2001a, 2001b).

The October 2001 Greenhouse Gas Protocol provides the following additional guidance for reporting indirect emissions from imported electricity, steam and other heat (WRI 2001a).

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

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

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

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

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

- emissions from CHP systems calculated using the “work potential” method (worksheet “CHP option 2”).

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

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

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

ANNEX E

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 12.7 of *Calculation Tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills* 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 mill is exporting power from a CHP system but using the steam internally, it may be necessary to estimate how much of its emissions to attribute to the exported electricity.

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

2.0 OVERVIEW OF METHODS

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

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

The “efficiency” method is based on allocating emissions according to the amount of fuel used to produce each energy output. The method uses either assumed or estimated

efficiencies for conversion of energy at various points in the process to back calculate the amounts of fuel associated with each output energy stream. This method can be used in a simplified or detailed manner, and is the approach recommended in the pulp and paper industry 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 briefly described below, 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 is identical to Section 12.7.1 in the report

2.1.1 *Simplified Efficiency Method*

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

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

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

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

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

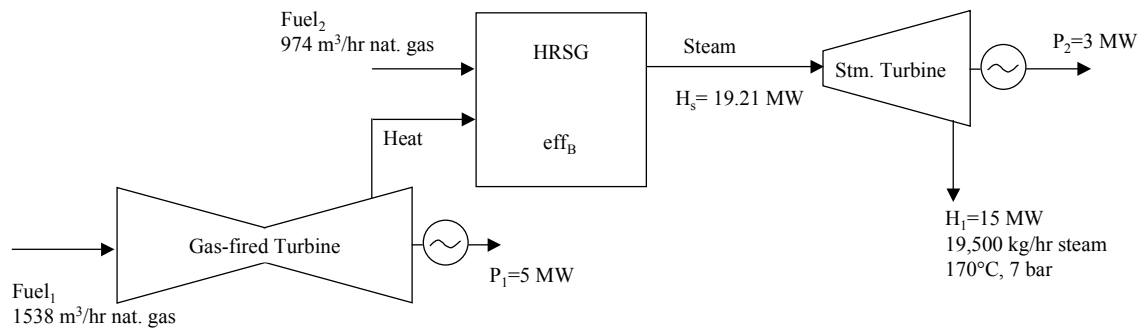
where: E_P = emissions share attributable to electric power production

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

In using the simplified efficiency method, WRI/WBCSD recommends that an efficiency of 0.35 be used for power generation and 0.8 be used for steam (or hot water) generation (WRI 2001b, c), corresponding to a ratio of efficiencies (R_{eff}) of 2.3. The first example calculation below makes use of these recommended default efficiency factors.

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

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; 0.35 for power generation and 0.8 for steam generation (WRI 2001b, 2001c).



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

Total system emissions:

Fuel₁:
CO₂ (1538 m³/hr) x (0.039 GJ/m³) x (55.9 kg CO₂/GJ) = 3353 kg CO₂/hr

$$\begin{aligned}
\text{CH}_4 & (1538 \text{ m}^3/\text{hr}) \times (0.039 \text{ GJ/m}^3) \times (0.0006 \text{ kg CH}_4/\text{GJ}) \times (21 \text{ CO}_2\text{-eq.} / \text{CH}_4) \\
& = 0.76 \text{ kg CO}_2\text{-eq./hr} \\
\text{N}_2\text{O} & (1538 \text{ m}^3/\text{hr}) \times (0.039 \text{ GJ/m}^3) \times (0.0001 \text{ kg N}_2\text{O} / \text{GJ}) \times (310 \text{ CO}_2\text{-eq.} / \text{N}_2\text{O}) \\
& = 1.86 \text{ kg CO}_2\text{-eq./hr} \\
\text{Total Fuel}_1 \text{ emissions} & = 3356 \text{ kg CO}_2\text{-eq./hr}
\end{aligned}$$

Fuel₂:

$$\begin{aligned}
\text{CO}_2 & (974 \text{ m}^3/\text{hr}) \times (0.039 \text{ GJ/m}^3) \times (55.9 \text{ kg CO}_2/\text{GJ}) = 2123 \text{ kg CO}_2/\text{hr} \\
\text{CH}_4 & (974 \text{ m}^3/\text{hr}) \times (0.039 \text{ GJ/m}^3) \times (0.0014 \text{ kg CH}_4/\text{GJ}) \times (21 \text{ CO}_2\text{-eq.} / \text{CH}_4) \\
& = 1.12 \text{ kg CO}_2\text{-eq./hr} \\
\text{N}_2\text{O} & (974 \text{ m}^3/\text{hr}) \times (0.039 \text{ GJ/m}^3) \times (0.0001 \text{ kg N}_2\text{O} / \text{GJ}) \times (310 \text{ CO}_2\text{-eq.} / \text{N}_2\text{O}) \\
& = 1.18 \text{ kg CO}_2\text{-eq./hr} \\
\text{Total Fuel}_2 \text{ emissions} & = 2126 \text{ kg CO}_2\text{-eq./hr}
\end{aligned}$$

$$\text{Total CHP system emissions} = 3356 + 2126 = 5482 \text{ kg CO}_2\text{-eq./hr}$$

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

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

$$E_H = \left\{ \frac{15 \text{ MW}}{15 \text{ MW} + (8 \text{ MW} \times 2.3)} \right\} \times 5482 \text{ kg CO}_2 \text{ eq} = 2462 \text{ kg CO}_2 \text{ eq} = 20,681 \text{ t CO}_2 \text{ eq/y at 350 d/y operation}$$

$$E_P = 5482 \text{ kg CO}_2 \text{ eq} - 2462 \text{ kg CO}_2 \text{ eq} = 3020 \text{ kg CO}_2 \text{ eq} = 25,368 \text{ t CO}_2 \text{ eq/yr at 350 d/y operation}$$

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 = $100 \times 2462 / 5482 = 44.9\%$
- Percentage of CHP emissions to power output = $100 \times 3020 / 5482 = 55.1\%$

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 = $(2462 \text{ kg CO}_2\text{-eq./hr}) / 15 \text{ MW}$
= $164.1 \text{ kg CO}_2\text{-eq./MWh}$
- Emission factor for CHP power output = $(3020 \text{ kg CO}_2\text{-eq./hr}) / 8 \text{ MW}$
= $377.5 \text{ kg CO}_2\text{-eq./MWh}$

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:

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

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

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

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

E_T = total emissions from the CHP plant

H_1 = heat output contained in steam stream 1

H_2 = heat output contained in steam stream 2

P_1 = power output from generator 1

P_2 = power output from generator 2

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

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

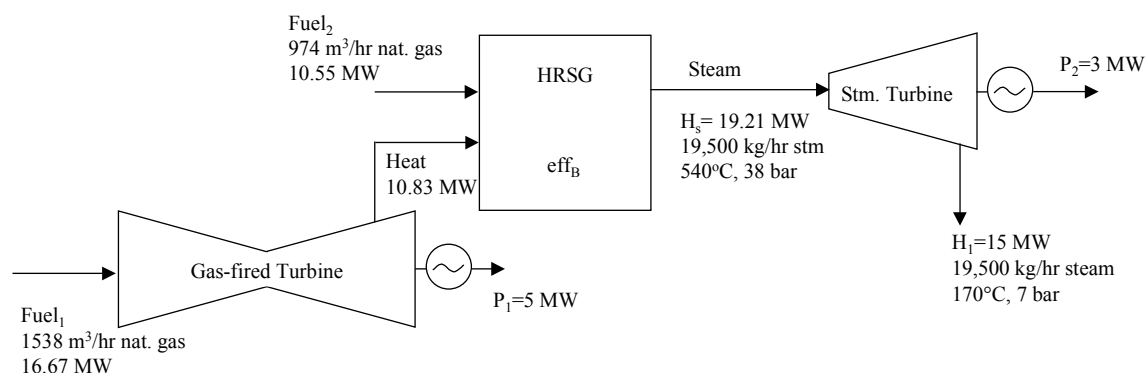
e_{PI} = overall efficiency of producing electric power via generator 1

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

Mills 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 Fuel₁ emissions = 3356 kg CO₂-eq./hr

Total Fuel₂ emissions = 2126 kg CO₂-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:

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

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

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

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

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 H₁ 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 P₂ is:

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

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

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

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

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

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

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

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

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

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

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

As an example, consider a CHP system which emits a total of 174,000 tonnes of carbon dioxide per year with total energy outputs as shown in Table 1. The useful energy content of electricity is equivalent to the total energy, and for the three steam streams the useful energy is calculated from Equation 5. Allocated carbon dioxide emissions and an emission factor (ton CO₂ per GJ of total energy) for each energy output are also shown in Table 1.

Table 1. Allocation of GHG Emissions Based on the Heat Content Method

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

2.3 Work Potential Method

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

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

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

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

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

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

S_{ref} = the specific entropy at reference conditions

T_{ref} = the temperature at reference conditions

Table 2 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 2. Allocation of GHG Emissions Based on the Work Potential Method

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

ANNEX F

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, with highway travel being the most significant component of mobile source emissions, by far. 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 vehicle. The WRI/WBCSD Protocol Scope 1 reporting requirements include all direct emissions, regardless of where they occur (WRI 2001a). 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 is 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 and WRI/WBCSD (IPCC 1997c and WRI 2001d). The WRI/WBCSD calculation tools for transportation emissions are available on the internet (WRI 2001d) and are briefly summarized here as well. The Excel® workbook that accompanies this report incorporates the transportation calculation tools from WRI/WBCSD.

1.1 Carbon Dioxide

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

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

In some cases, a authorities issue a single emission factor shown in CO₂-equivalents that incorporates emissions of CH₄ and N₂O. In the Australian Greenhouse Challenge, for instance, the emission factors not only include all three GHGs, they also include the impact of upstream emissions from fuel extraction, processing, and transportation (i.e., “full fuel cycle emissions”).

1.2 Methane and Nitrous Oxide

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

The Reference Manual of IPCC’s Revised 1996 Guidelines contains emission factors for “surface non-road sources.” (IPCC 1997c, page 1.88) The Revised 1996 Guidelines include emission factors published by EMEP/CORINAIR Atmospheric Emissions Inventory Handbook, most recently updated in 1996, and by the US EPA. Both sets of emission factors are shown in the following tables.

Table 1. Fuel Consumption-Based N₂O and CH₄ Emission Factors
for Non-Road Mobile Sources and Machinery (IPCC 1997c)
(IPCC Revised 1996 Guidelines taken from EMEP/CORINAIR)

<i>Source and Engine Type</i>	<i>g N₂O/kg fuel</i>	<i>g N₂O/MJ</i>	<i>g CH₄/kg fuel</i>	<i>g CH₄/MJ</i>
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

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

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

Table 2. N₂O and CH₄ Emission Factors for Non-Highway Vehicles (IPCC 1997c)
(IPCC Revised 1996 Guidelines taken from US EPA)

<i>Source and Engine Type</i>	g N ₂ O/kg fuel	g N ₂ O/MJ	g CH ₄ /kg fuel	g CH ₄ /MJ
<i>Ships and boats</i>				
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
<i>Locomotives</i>				
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
<i>Farm Equipment</i>				
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
<i>Construction</i>				
Gas Construction	0.08	0.002	0.18	0.004
Diesel Construction	0.08	0.002	0.18	0.004
<i>Other Non-highway</i>				
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

Table 3. CORINAIR Engine Output-Based N₂O and CH₄ Emission Factors for Non-Road Mobile Sources and Machinery (EEA 1999)

<i>Source and Engine Type/Size</i>		N ₂ O (g/kWh)	CH ₄ (g/kWh)
<i>Baseline factors</i>			
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
<i>Pollutant weighting factors for diesel engines (multiply baseline factors shown above by these values)</i>			
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
<i>Degradation factors (increase emission factors calculated above by these values)</i>			
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 (AGO 2001b)

Manufacturers participating in the Australian Greenhouse Challenge estimate emissions using emission factors that include CO₂, CH₄, and N₂O, and also address full fuel cycle emissions (i.e., they include upstream emissions from fuel extraction, processing and transport) (AGO 2001b).

1.2.4 Finland - Greenhouse gas emissions and removals in Finland – April 9, 2001

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

Table 4. Finnish Emission Factors for Forestry and Industrial Machinery
(Technical Research Center of Finland 2001)

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

1.2.5 United Kingdom

In the development of the UK national inventory, emission factors for off-road sources of GHG emissions from fossil fuel combustion are mostly from the EMEP/CORINAIR 1996 Emission Inventory Handbook (AEA Technology 2001).

1.2.6 Canada - FPAC Greenhouse Gas Action Plan Guidelines – 2001

FPAC does not include transportation related emissions in its guidance to mills because Environment Canada has notified FPAC that “companies should not calculate emissions for transportation fuels as these emissions are already accounted for in Canada’s GHG inventory...” (FPAC 2001). The Canadian government inventory document uses the IPCC/EMEP/CORINAIR non-road vehicle emission factors from the 1996 Revised IPCC Guidelines, after converting them to a fuel volume basis (i.e., grams of emission per litre of fuel) (IPCC 1997c).

1.2.7 WRI/WBCSD Greenhouse Gas Protocol and supporting documents

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

Table 5. Default Emission factors and heating values for different transportation fuels (WRI 2001d)

Fuel type	Based on Lower Heat Value		(derived)	(derived)		(derived)
	kg CO ₂ / GJ	GJ / litre	GJ/ US gallon	GJ/Imp Gal	GJ / litre	GJ/tonne
Gasoline / petrol	69.25	0.0344	0.1302	0.1564	0.0344	43.5674
Kerosene	71.45	0.0357	0.1351	0.1623	0.0357	44.0768
Jet Fuel	70.72 (EIA)					44.5900
Aviation gasoline	69.11 (EIA)	0.0343	0.1299	0.1561	0.0343	
Diesel	74.01	0.0371	0.1404	0.1687	0.0371	44.1667
Distillate fuel oil No.1	74.01	0.0371	0.1404	0.1687	0.0371	43.9211
Distillate fuel oil No.2	74.01	0.0371	0.1404	0.1687	0.0371	43.9211
Residual Fuel oil#4	74.01	0.0379	0.1435	0.1723	0.0379	
Residual Fuel oil#5	77.30	0.0397	0.1503	0.1805	0.0397	39.9535
Residual Fuel oil#6	77.30	0.0405	0.1533	0.1841	0.0405	40.7586
LPG	63.20	0.0249	0.0942	0.1132	0.0249	45.9779
Lubricants	73.28	0.0382			0.0382	
Anthracite	98.30	0.02860 GJ/kg			27'177 GJ / kg	
Bituminous coal	94.53	0.0302 - 0.0326 GJ/kg			28'724 - 30'999 GJ / kg	
Butane		0.0258			0.0258	
Propane	62.99 (EIA)	0.0240			0.0240	47.3373
Anthracite	98.30					23.53 *
Bituminous coal	94.53					23.53 *
Sub-bituminous coal	96.00					23.53 *
Wood, wood waste	100.44 (EIA)					
Natural gas	56.06	0.039 GJ / standard cubic meter			0.039 GJ / standard cubic meter	

Table 6. Default Fuel economy factors for different types of mobile sources and activity data (WRI 2001d)

Vehicle Type	Liters/100km	mpg	gram CO ₂ / km
New small gas/electric hybrid	4.2	56	100.1
Small gas auto, hghwy	7.3	32	175.1
Small gas auto, city	9.0	26	215.5
Medium gas auto, hghwy	7.8	30	186.8
Medium gas auto, city	10.7	22	254.7
Large gas automobile, hwy	9.4	25	224.1
Large gas automobile, city	13.1	18	311.3
Medium Station wagon, hwy	8.7	27	207.5
Med 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 Trucks, hwy	10.7	22	254.7
Pick-up Trucks, city	13.8	17	329.6
Large Pick-up Trucks, hwy	13.1	18	311.3
Large Pick-up Trucks, city	15.7	15	373.5
LPG automobile	11.2	21	266
Diesel automobile	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 G

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

1.0 RECOMMENDED APPROACH FOR ESTIMATING CH₄ EMISSIONS FROM LANDFILLS – Note: Much of Sections 1.0 through 1.2.1 is identical to Section 14 in the Calculation Tools Report

These calculation tools have been developed assuming that many companies will include mill-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. The reporting format, however, has been prepared assuming that only the emissions from company-owned landfills will be reported.

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

In Table 1 of the main body of this report, an emission factor for landfilled waste is presented. 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 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 below, 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, using methods described below. The problem with this approach is that, because of the large uncertainties in estimating methane generation, the amounts burned (which were measured) could easily be greater than the amounts generated (which were 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 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%, it means that 100 tons of methane were generated.

The problem with this approach is that the effectiveness of landfill gas collection systems is variable and uncertain. Reported collection efficiencies range from 60 to 85% (USEPA 1998). This variability and uncertainty has caused IPCC to take the position that “the use of undocumented estimates of landfill gas recovery potential is not appropriate, as such estimates tend to overestimate the amount of recovery” (IPCC 2000). Nonetheless, this approach is built around a measured value – the amount of gas collected. For this reason, 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 mill landfills because of the limited data for deriving the parameter values needed to use IPCC’s default methodology on pulp and paper mill wastes.

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

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

Using these default values and assumptions, estimates of methane generation can then be developed by using the following equation.

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

where:

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

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

FRMETH = fraction 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 Mill Landfills without Gas Collection Data

1.2.1 The Simplified First Order Decay Approach

Where the approach described above 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 2000). It can be used to estimate CH₄ emissions from active and inactive landfills and involves the following analysis.

In cases where the annual deposits are constant (or assumed to be) 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 (e.g., a new deinking mill is built on-site), 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). The simplified approach is as follows.

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

where:

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

*L*₀ = ultimate methane generation potential, m³/Mg waste

k = methane generation rate constant, 1/y

C = time since landfill stopped receiving waste, y

T = years since landfill opened, y

(Note: *R* and *L*₀ can be in units of wet weight, dry weight, degradable organic carbon, or other units but the units for *R* and *L*₀ must be the same.)

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

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

where:

*CH*₄ generated = from Equation 2

*CH*₄ recovered = amount of methane collected, site specific determination

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

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

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

A number of sources for the parameter values L_0 and k needed in these equations are shown below. 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 shown below. Using this variation, starting in year one, you calculate how much methane will be generated in each subsequent year by waste deposited in that year using the following equations.

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

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

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

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

where:

CH_4 generated = from Equation 5

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 you need to 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 mill sludges, 25 years is probably the minimum that would satisfy this criterion. For each year's deposit, you then 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 pulp and paper mill landfills is even more uncertain. The guidance offered by the sources reviewed in this study is summarized as follows.

IPCC – k varies from 0.005 to 0.4 per year, with a default of 0.05/yr for MSW (IPCC 1997c)

UK – k varies from 0.05/yr for slowly degrading waste to 0.185/yr for rapidly degrading waste (AEA Technology 2001)

Sweden – k equals 0.092/yr for all landfills (Swedish Environmental Protection Agency 2001)

Canada – k for wood waste landfills equals 0.01/yr, varies from 0.003/yr to 0.028/yr for MSW landfills (Environment Canada 1999)

EPA – k equals 0.04/yr for areas receiving at least 25 inches (63.5 cm) of precipitation and 0.02/yr for drier areas (for MSW landfills) (USEPA 1998)

1.2.4 Ultimate methane generation potential, L_0

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

IPCC – The sources cited by IPCC indicate that L_0 can vary from less than 100 to over 200 m^3/Mg . The following equation is provided for calculating a site-specific L_0 (IPCC 1997c).

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

relative to a managed landfill)

For MSW landfill default values, IPCC recommends the following (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 meters deep), and 0.8 for deeper unmanaged landfills is 0.8.

UK – The equation above is used to calculate L_0 . The DOC for different types of waste was determined from a national study. DOC_f was assumed to be 0.6. F was usually 0.5 but 0.3 was used for old shallow sites. MCF was assumed to be 1.0 (AEA Technology 2001).

Sweden – Sweden uses an L_0 of 45 kg CH₄/ton of waste specifically for pulp and paper mill sludge landfills. This is equivalent to 63 m³/Mg (Swedish Environmental Protection Agency 2001).

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

DOC = 0.4 for paper and cardboard, wet weight basis

= 0.3 for wood and bark, wet weight basis

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

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

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

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

DOC_f = Finland uses 0.5 to reflect the low temperature and less-than-optimal conditions for decomposition in Finnish landfills

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

F = 0.5

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

Canada – To calculate the methane potential for wood waste landfills, Canada uses an L_0 of 118 kg CH₄/ton wood waste which converts to 165 m³/Mg. The value for MSW landfills is 117 kg CH₄/ton (Environment Canada 1999).

US EPA – EPA's compilation of emission factors (AP-42) indicates that a value of 100 m³/Mg is recommended as the default factor for most MSW landfills (USEPA 1998).

1.2.5 Recommended Default Values for k and L_0

For situations where pulp and paper mill wastewater treatment sludge is a major constituent 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 m³/Mg and 200 m³/Mg. NCASI is currently conducting research that should narrow these ranges. Initial indications are that the amounts of gas generated in mill 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 mill wastes, companies use the parameters values shown in Table 1.

Table 1. Recommended Default Values for k and L_0 for Estimating Mill Landfill Methane Emissions

Parameter	Default Value
k	0.03 y ⁻¹
L_0	100 m ³ /Mg dry weight of waste

2.0 RECOMMENDED APPROACH FOR ESTIMATING CH₄ EMISSIONS FROM THE ANAEROBIC TREATMENT OF WASTEWATER OR SLUDGE

– Note: Most of Sections 2.0 through 2.2 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 CH₄ emissions need to be estimated because (a) the CO₂ emitted from wastewater and sludge treatment operations contains biomass carbon which is not included in most GHG protocols and (b) other protocols assume that N₂O emissions, if any, occur after the wastewater is discharged.

2.1 Anaerobic Treatment Operations where Off-Gases are Captured

In many cases, anaerobic treatment systems are covered and the gases are collected and burned. One of the purposes of these collection systems is the prevention of odors, and to accomplish this objective, the systems must be highly efficient. For purposes of a GHG inventory it is reasonable to assume, therefore, that where methane emissions from anaerobic treatment operations are captured and burned, the collection and destruction is complete and no methane is emitted. If circumstances at a 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 the equation below (IPCC 2000). Although the IPCC document allows the following equation to be applied to systems that are not completely anaerobic (by multiplying the result of the following equation by an arbitrary adjustment factor of less than one) there are no data currently available to support the selection of the adjustment factor. It is recommended, therefore, that methane emissions only be estimated from anaerobic treatment or sludge digestion systems until such time as factors for other types of systems are available.

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

where:

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

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

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

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

where:

OCs = organic content of the sludge

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

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

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

3.0 OVERVIEW OF EXISTING APPROACHES

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

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

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

The IPCC default methodology for estimating methane emissions from landfills is limited to municipal solid waste landfills. Chapter 6 of the 1996 IPCC Guidelines Reference Manual (IPCC 1997c) and Chapter 5 of the May 2000 Good Practices document (IPCC 2000) outline two general approaches for estimating landfill emissions. The first approach assumes that all organic matter degrades in the year it is placed in the landfill while the second approach uses a first order model to estimate the amounts released over time. The Good Practices document indicates that the first order decay approach should be used where possible (IPCC 2000).

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

Table 2. Default DOC Values for Major Waste Streams from IPCC’s 1996 Revised Methodology
(values are for “wet or fresh” materials in municipal solid waste)

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

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

IPCC then applies a factor, the methane correction factor or MCF, which is intended to account for the fact that landfill design and operation can influence the tendency of degradable carbon to decompose into carbon dioxide rather than methane. The MCF is simply a measure of the relative methane generation potential of unmanaged landfills compared to managed landfills. A landfill is a “managed landfill” 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 meters deep) is 0.4 while the factor for deeper unmanaged landfills is 0.8. At a managed landfill, the default assumption is that methane comprises 50% of the landfill gas. The MCFs modify this assumption for unmanaged landfills; i.e., methane comprises 40% of the gas from deep unmanaged landfills ($0.8 \times 50\%$) and 20% of the gas from shallow unmanaged landfills ($0.4 \times 50\%$).

At many landfills, gas is trapped and burned, 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 the following calculations-

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

Where

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

DOC_f = fraction of DOC that degrades into landfill gas

16/12 = conversion factor from carbon to methane

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

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

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

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

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

3.1.2 Landfills – The First Order Decay Approach

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

3.1.3 Wastewater treatment and anaerobic sludge digestion

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

The Waste section of the 1996 Revised Guidelines contains a method for estimating N₂O emissions from “human sewage” (IPCC 1997c, page 6.28). The discussion in the Waste section directs the reader to the Agriculture section of the Manual for more information. In that section of the manual, IPCC indicates that three studies have examined nitrous oxide

emissions from operating wastewater treatment facilities (IPCC 1997c, page 4.110). All of the studies reported low N₂O emissions. For this reason, in IPCC's methodology, "N₂O associated with sewage treatment and land disposal is assumed to be negligible" and it is further assumed that "all sewage nitrogen enters rivers and/or estuaries" where a portion of it is converted into N₂O (IPCC 1997c). In summary, IPCC's guidance contains methods for estimating the N₂O released from human sewage once it is discharged, but assumes that N₂O emissions from the treatment plants are negligible. There is no discussion of N₂O emissions from pulp and paper or other industrial wastewater treatment plants.

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

The Reference Manual of IPCC's 1996 Revised Guidelines contains the following discussion of pulp and paper industry waste treatment operations. (IPCC 1997c, page 6.16)

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

Using these criteria, IPCC cites work by Doorn and Eklund suggesting that the 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 the following equation:

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

Where:

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

B₀ = CH₄ per unit of organic matter, in units consistent with TOW or TOS

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

First the amount of degradable substrate being fed to the treatment unit is determined. The total organic (chemical oxygen demand, COD) in wastewater is given the symbol TOW while the total organic in sludge is given the symbol TOS. The IPCC reference manual contains some limited data that can be used to estimate pulp and paper mill wastewater COD, but the data are not included in this report because the 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 above, while emissions from sludge digestion would be calculated using equation 10 above. In cases where sludge is burned, it is included in the calculations for GHG emissions from biomass burning, discussed elsewhere.

For industrial wastewaters, the maximum methane producing capacity is given the symbol B_0 and is expressed in kg CH₄/kg COD. IPCC's 1996 Revised Guidelines give a default value for B_0 of 0.25 kg CH₄/kg COD for wastewater and sludge. A footnote in the IPCC guidelines explains that since the degradable organic matter in COD is the same material that is measured as degradable BOD, the factor B_0 will be 0.25 kg CH₄/kg COD or BOD. This is approximately true if the factors are based on the kg of 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 the following explanation. (IPCC 2000, page 5.17)

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

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

organic content removed during treatment. This can be especially important for many pulp and paper mill wastewaters where the COD to BOD ratio can be very high.

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. For completely aerobic systems, the MCF 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 Australia – Greenhouse Challenge Factor and Methods Workbook (AGO 2001b)

3.2.1 Landfills

The Greenhouse Challenge workbook uses the IPCC all-in-one-year approach for estimating emissions from municipal solid waste landfills .

3.2.2 Industrial Wastewater Treatment

Total emissions from industrial wastewater are the sum of emissions from wastewater treatment and sludge treatment and are calculated from the following equation, which is essentially the same approach as suggested by IPCC for anaerobic wastewater and sludge treatment operations (AGO 2001b). Although the AGO Greenhouse Challenge workbook does not specifically indicate that the equation is to be used only for anaerobic treatment operations, it is clearly not appropriate for aerobic or facultative treatment operations.

$$\begin{aligned} \text{GHG emissions (t CO}_2\text{-equiv.)} &= \\ &= [((W \times O \times \text{DOC}_w \times (1 - F_{sl}) \times EF_w) + (W \times O \times \text{DOC}_{sl} \times F_{sl} \times EF_{sl})) - R] \times 21 / 1000 \\ &= [W \times O \times ((\text{DOC}_w \times (1 - F_{sl}) \times EF_w) + (\text{DOC}_{sl} \times F_{sl} \times EF_{sl})) - R] \times 21 / 1000 \quad (\text{Eq. 11}) \end{aligned}$$

Where: Wastewater (*W*) = wastewater in m³ per ton of product

Output (*O*) = company output per annum in ton

DOC_w = quantity in kilograms of COD/m³ wastewater

F_{sl} = fraction of organic degradable organic component removed as sludge,
default = 0.54

DOC_{sl} = quantity in kilograms of COD/m³ sludge

EF_w = methane emission factor for industrial wastewater, default = 0.25 kg
CH₄/kg COD

EF_{sl} = methane emission factor for industrial sludge, default = 0.25kg CH₄/Kg
COD

R = recovered CH₄ in the inventory year and measured in ton

21 = the global warming potential (GWP) of CH₄

3.3 Canada – FPAC’s 2001 Greenhouse Gas Action Plan Guidelines (FPAC 2001) and Canada’s Greenhouse Gas Inventory, 1997 Emissions and Removals with Trends (Environment Canada 1999)

The FPAC “2001 Greenhouse Gas Action Plan Guidelines” do not specifically include emissions from waste management activities.

These emissions are included, however, in “Canada’s Greenhouse Gas Inventory, 1997 Emissions and Removals with Trends” (Environment Canada 1999).

Canada does not count CO₂ produced by the decomposition of biomass carbon. Estimates are made for CH₄ and N₂O emissions, however (Environment Canada 1999).

3.3.1 *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 following description highlights only those aspects of the Canadian approach that either involve Canada-specific parameter values or represent departures from the IPCC approach (Environment Canada 1999).

Because of the large size of the forest products industry in Canada, the government developed separate estimates of methane emissions from wood waste landfills. After evaluating the recommendations developed by Canadian experts for “k” values to model municipal solid waste (MSW) landfills, the government decided to use the lowest “k” value for MSW in the major forest industry provinces to estimate emissions from wood waste landfills. This “k” was 0.01/yr. The Canadian government considered the degradable carbon content of wood waste and assumed that wood waste landfill gas would consist of 50% methane to calculate a methane generation potential, L₀, for wood waste of 118 kg CH₄/tonne of wood waste (Environment Canada 1999).

3.3.2 *Wastewater treatment and sludge digestion*

Canada only estimated GHG emissions from municipal wastewater treatment due to lack of data on treatment of industrial wastewater (Environment Canada 1999).

Methane emissions from aerobic systems were assumed to be negligible, an assumption consistent with IPCC’s guidance. Emissions from anaerobic systems were estimated using an approach developed by Ortech International for Environment Canada in 1994. Using this approach, it was estimated that 4.015 kg CH₄/person/year could potentially be emitted from wastewater treated anaerobically (Environment Canada 1999). This factor was multiplied by the number of persons in each province and the fraction of the wastewater treated

anaerobically in each province to estimate methane emissions from the anaerobic treatment of municipal wastewater.

Canada used the IPCC default methodology for estimating N₂O emissions from human sewage. The IPCC methodology assumes that (a) negligible amounts of N₂O are released during treatment, and (b) all of the nitrogen in untreated human sewage is discharged to rivers or estuaries, where a portion of the nitrogen is converted to N₂O (Environment Canada 1999).

3.4 Finland - Greenhouse gas emissions and removals in Finland (Technical Research Center of Finland 2001)

3.4.1 Landfills

The Finnish government's estimates are based on IPCC's all-in-one-year default method (IPCC 1997c). 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. See the description of the IPCC all-in-one-year approach for more information on the variables and calculations.

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

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 since deinking sludge is listed separately)

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

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

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

DOC_f = 0.5 (This is the fraction of the degradable organic carbon that is 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 (The Methane Correction Factor is essentially the landfill's methane generation potential relative to a "managed" landfill. Finland assumes that one-half of waste goes to small landfills with MCF=0.4 and with the rest going to large landfills with MCF=1)

F = 0.5 (fraction of landfill gas that is methane. IPCC default assumption that landfill gas is 50% methane)

16/12 = factor to convert from carbon to methane

R = Amount of landfill methane recovered. The value varies from year to year.

OX = 0.1 (10% of the methane that is not recovered is oxidized to CO₂ in the upper layers of the landfill cover.)

3.4.2 Wastewater treatment and sludge digestion

Finland uses IPCC's default methodology to estimate methane emissions from wastewater treatment (Technical Research Center of Finland 2001).

$$\text{Emissions of CH}_4 = \text{Organic load} \times B_0 \times \text{MCF} \quad (\text{Eq.13})$$

where: Organic Load is expressed (in Finland's case) as COD for industrial wastewaters and BOD in domestic wastewaters

B₀ = the maximum methane generation potential – Finland uses the default value given in the IPCC 1996 Revised Guidelines of 0.25 kg CH₄/kg COD or BOD. IPCC's May 2000 Good Practices document revised the default value to 0.25 kg CH₄/kg COD and 0.6 kg CH₄/kg BOD.

MCF = a weighted average value reflecting the methane generation potential of the treatment plants in Finland relative to an anaerobic treatment plant. For domestic wastewaters, Finland used an MCF of 0.025, while for industrial wastewaters it used 0.005.

Emissions of N₂O 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 also in industrial wastewaters and fish farm wastes (Technical Research Center of Finland 2001). The IPCC method estimates the N₂O released from wastewater once it is discharged, but assumes that N₂O emissions from the treatment plants are negligible.

3.5 France – “Inventaire des émissions de gaz à effet de serre en France de 1990 à 1999” [Inventory of Greenhouse Gas Emissions in France for the Period 1990-1999] (CITEPA 2000)

3.5.1 Landfills

France's inventory document explains that the country has changed from IPCC's all-in-one-year approach (called the “zero-order” approach in the French document) to IPCC's first order decay model approach (CITEPA 2000, Section 4.6).

Appendix 3 of the French Inventory document indicates that the estimates were developed from national survey information describing the approximately 500 landfills in the country, a number that is becoming smaller with time (CITEPA 2000). The data and modeling assumptions were developed in consultation with France's Agency for Environmental and Energy Management (ADEME). The estimates were developed using the first order decay model approach with emissions being a function of a number of factors including the degradability of the waste, other waste characteristics such as the degree of compaction, and the recovery of landfill gas (CITEPA 2000).

3.6 Japan - Information from the Japan Paper Association (JPA 2001)

3.6.1 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

3.7 Sweden - Sweden's National Inventory Report 2001 (Swedish Environmental Protection Agency 2001)

3.7.1 Landfills

In "Sweden's National Inventory Report 2001," Sweden uses an approach very similar to IPCC's first order decay approach to estimate methane emissions from landfill. 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 Environmental Protection Agency 2001).

The Swedish government has examined methane generation from pulp mill sludge landfills. It uses a value of 45 kg CH₄/ton of waste to represent the methane generation potential for landfilled pulp mill sludge (Swedish Environmental Protection Agency 2001).

The other values used in the first order model for methane emissions from landfills are as follows (Swedish Environmental Protection Agency 2001):

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 that is degraded to landfill gas) = 0.7

OX (fraction of non-collected gas that is oxidized in the 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

3.7.2 Wastewater treatment and sludge digestion

The Swedish National Inventory Report indicates that “[e]missions of nitrous oxide from wastewater handling are considered to be insignificant since almost all wastewater is treated in aerobic conditions. Emissions from wastewater handling are therefore not reported” (Swedish Environmental Protection Agency 2001).

Sludge-related emissions of methane from landfills are estimated as explained above. GHG emissions from anaerobic sludge digestion are not discussed, although the report notes that the landfill gas potential of already digested sludge is reduced by 50% (Swedish Environmental Protection Agency 2001).

3.8 United Kingdom - UK Greenhouse Gas Inventory, 1990-1999 (AEA Technology 2001)

3.8.1 Landfills

The method used by the UK to develop national emission estimates for landfills is described in Appendix 7 of the UK Greenhouse Gas Inventory (AEA Technology 2001).

“The UK method conforms to good practice since a first order decay (Tier 2) methodology is used based on estimates of historical data on waste quantities, composition and disposal practices over several decades.”

“The UK method is based on equations 4 and 5 in the Revised 1996 IPCC guidelines... which are compatible with equations 5.1 and 5.2 in the Good Practice Guidance.... A slightly different version of equation 5.1 is used, which takes into account the fact that the model uses a finite time interval (one year).”

“The UK method divides the waste stream into four categories of waste: rapidly degrading, moderately degrading, slowly degrading and inert waste. These categories each have a separate decay rate. The decay rates are based on data from the Netherlands and range from 0.05 (slowly degrading waste) to 0.185 (rapidly degrading waste), which lie within the range of 0.03 to 0.2 quoted in the Good Practice Guidance.”

“The model extends back to 1945, which gives a time period of around 4 half lives for the slowest of the three decay rates (0.05, half life 14 years). This lies within the range of 3 to 5 half lives recommended by the Good Practice Guidance.”

“The model distinguishes between four separate categories of landfill site with different degrees of gas collection control:

- closed sites;

- sites with no gas collection;
- sites with limited collection;
- sites with comprehensive collection.”

“Each site type has different gas collection and oxidation rates. As recommended, the model attempts to take into account changes in landfill practice over past decades by altering the proportion of waste disposed of to each of these categories of site in past years, and also by modifying the gas collection rate over time where appropriate. The model also simulates retrofitting of sites, i.e., upgrading from a site with no gas control or limited gas control to one with comprehensive gas control.”

“The estimates of historical waste disposal and composition data are based on various data sources... As recommended in the Good Practice Guidance, estimates for municipal waste are based on population where data is absent.”

“As recommended in the Good Practice Guidance, the estimates of waste disposal quantities include commercial and industrial waste, demolition and construction waste and sewage sludge, as well as municipal waste. For industrial and commercial waste, the data are based on national estimates from a recent survey, although the survey was incomplete at the time of finalizing the model estimates. The data were extrapolated to cover past years based on employment rates in the industries concerned.”

“All sites in the UK are managed, and therefore have a methane correction factor of 1.0. However, as described above, differences in oxidation rates have been simulated by the practice of dividing waste disposal sites into four types as described above.”

“Degradable organic carbon (DOC) was estimated based on a national study, as recommended in the Good Practice Guidance. However the figures used were based on expert opinion rather than measured data.”

“The fraction of degradable organic carbon dissimilated (DOC_F) was assumed to be 60%. At the time when the model was set up, the IPCC recommended default value was 77%, but there were indications that this could be an overestimate, so a lower figure was used. The new IPCC recommended range quoted in the Guidance is 50-60%.”

“The fraction of CH_4 in landfill gas is generally taken to be 50%, which is in line with the Guidance. For old shallow sites it is taken to be 30% to reflect a higher degree of oxidation. The fraction of methane recovered was assumed to be 85% for sites with full gas control and 40% for sites with limited gas control. The estimates are not derived from metering data, as recommended by the Guidance, as such data were not readily available at the time of the study. A panel of UK industry experts selected the figures.”

“The oxidation factor is assumed to be 10% for all site types. Recovered methane is subtracted before applying the oxidation factor. This is in line with the Guidance...”

“Neither the GHGI nor the NAEI reports carbon dioxide emissions from the anaerobic decay of landfilled waste since this is considered to be part of the carbon cycle and is not a net source. The estimates include the contribution of sewage disposed of to landfill.”

3.8.2 Wastewater treatment

The method used by the UK to develop national estimates of GHG emissions from wastewater treatment is described in Appendix 7 of the UK Greenhouse Gas Inventory (AEA Technology 2001). That document explains that the UK does not attempt to estimate emissions from private wastewater treatment plants. The method used to estimate emissions from publicly owned treatment plants is described as follows (AEA Technology 2001).

“The methodology of the UK model differs in some respects from the IPCC default methodology. The main differences are that it considers wastewater and sewage together rather than separately. It also considers domestic, commercial and industrial wastewater together rather than separately. Emissions are based on empirical emission factors derived from the literature expressed in kg CH₄/tonne dry solids rather than the BOD default factors used by IPCC. The model however complies with the IPCC Good Practice Guidance as a national model...”

“The basic activity data are the throughput of sewage sludge through the public system. The estimates are based on the UK population connected to the public sewers and estimates of the amount of sewage per head generated. From 1995 onwards the per capita production is a projection.... The main source of sewage activity data is the UK Sewage Survey.... Emissions are calculated by disaggregating the throughput of sewage into 14 different routes. The routes consist of different treatment processes each with its own emission factor. The treatment routes and emission factors are shown in [the table below]...”

“The model accounts for recovery of methane and its subsequent utilization and flaring by estimating the proportion of anaerobic digester emissions that are recovered.”

“Nitrous oxide emissions from the treatment of human sewage are based on the IPCC... default methodology.”

Table 3. Methane Emission Factors for Sludge Handling kg CH₄/Mg dry solids, (AEA Technology 2001, from Table 1 of Appendix 7)

Sludge Handling System	Gravity Thickening ¹	Long-term Storage	Anaerobic Digestion ²	Agricultural Land
Anaerobic digestion to agriculture	0.72		143	5
Digestion, drying, agriculture	0.72		143	5
Raw sludge, dried to agriculture	0.72			20
Raw sludge, long term storage (3m), agriculture	0.72	36		20
Raw sludge, dewatered to cake, agriculture	0.72			20
Digestion, to incinerator	0.72		143	
Raw sludge, to incinerator	0.72			
Digestion , to landfill	0.72		143	
Compost, to agriculture	0.72			5
Lime raw sludge, to agriculture	0.72			20
Raw Sludge , to landfill	0.72			
Digestion , to sea disposal	0.72		143	
Raw sludge to sea disposal	0.72			
Digestion to beneficial use(e.g., land reclamation)	0.72		143	5

¹ An emission factor of 1 kg/t is used for gravity thickening, Around 72% of sludge is gravity thickened hence an aggregate factor of 0.72 kg CH₄/Mg is used.

² The factor refers to methane production, however it is assumed that 121.5 kg CH₄/Mg is recovered or flared.

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

3.9.1 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. The following description of the methodology is taken from EPA's "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1999" (USEPA 2001a, page 7-4).

"Based on available information, methane emissions from landfills were estimated to equal the methane produced from municipal landfills, minus the methane recovered and combusted, minus the

methane oxidized before being released into the atmosphere, plus the methane produced by industrial landfills.”

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

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

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

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

EPA also has a model, however, that is equivalent to the first order decay model suggested by IPCC. EPA’s first order model is described in its compilation of emission factors, AP-42 (USEPA 1998). EPA calls its model the Landfill Air Emissions Estimation Model (LAEEM). NCASI has reviewed EPA’s normal approach for estimating methane emissions from landfills and the results are reported in NCASI Technical Bulletin No. 790, September 1999 (NCASI 1999). The following material is taken mostly 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, which is 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 the 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 rain or more per year while a value of 0.02/yr is recommended for drier areas. A default value for methane generation potential, L_0 , of 100 m³ methane/Mg waste is recommended (USEPA 1998). An examination of the source of these recommendations by NCASI led to the conclusion that EPA’s default values (derived from studies of MSW landfills) is probably too high for pulp and paper industry landfills (NCASI 1999).

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

3.9.2 Wastewater treatment and anaerobic sludge digestion

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

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

EPA also develops separate estimates of methane emissions from pulp and paper industry wastewater treatment operations. The estimate was developed by assuming that one percent of the pulp and paper mill wastewater treated in mill-owned treatment plants is treated anaerobically in systems that allow the methane to escape to the atmosphere. The emission factor used was the same one EPA used for municipal wastewater treatment, 0.6 kg CH₄/kg BOD₅. For pulp and paper mills, however, EPA estimated methane emissions by multiplying the emission factor by the amounts of BOD removed in treatment. The IPCC factor of 0.6 kg CH₄/kg BOD is based, however, on organic matter in untreated wastewater. Because of the

high removal efficiencies for BOD in wastewater treatment, the discrepancy is relatively unimportant (USEPA 2001).

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

The WRI/WBCSD Protocol divides GHG emissions from waste management into those from company-owned sources (included in Scope 1 of the WRI/WBCSD Protocol) and those from sources owned by other entities (included in Scope 3). The tools for estimating these emissions are still under development (WRI 2001a).

ANNEX H

ALLOCATING GREENHOUSE GAS EMISSIONS FROM PARTLY OWNED OR PARTLY CONTROLLED SOURCES – OVERVIEW OF METHODS IN EXISTING PROTOCOLS

1.0 INTRODUCTION

Those protocols that are focused on geographic or national inventories have no need to address the question of corporate “ownership” of emissions from jointly-owned or –operated facilities. This leaves only a few of the protocols that address the question. The WRI/WBCSD GHG Protocol offers the most comprehensive discussion of this issue and should be viewed as a primary resource for companies having to determine the ownership of emissions from sources that are partly owned or controlled.

1.1 Canada - FPAC’s 2001 Greenhouse Gas Action Plan Guidelines

FPAC’s 2001 Greenhouse Gas Action Plan Guidelines do not directly address the question of how to allocate emissions from jointly owned or operated facilities except for combined heat and power projects reported under Canada’s Baseline Protection Initiative. In this case, FPAC indicates that “[p]arties involved in co-generation projects may decide between themselves how to share direct reductions” (FPAC 2001).

1.2 United States - U.S. Department of Energy 1605(b) program guidelines

This voluntary project-level reporting program does not specify how to allocate emissions or emissions reductions involving more than one corporate entity. The Department of Energy leaves it to the participating companies to decide this, requiring only that the allocation be transparent (USDOE 2000).

1.3 WRI/WBCSD - The Greenhouse Gas (GHG) Protocol Initiative

In October 2001, WRI/WBCSD released “The Greenhouse Gas Protocol – a corporate accounting and reporting standard.” The following material is taken entirely from that document, which companies facing this issue will want to obtain and read in its entirety (WRI 2001a).

“When accounting for GHG emissions from partially-owned entities/facilities, it is important to draw clear organizational boundaries, which should be consistent with the organizational boundaries which have been drawn up for financial reporting purposes. “

“Financial reporting is based upon the concepts of ‘control’ and ‘influence’. The concepts of ‘control’ and ‘influence’ are often defined and applied differently according to a company’s specific financial accounting and

reporting policies/practices. Where possible, it makes sense to follow company-specific distinctions already in place for financial accounting, provided these are explicitly explained and followed consistently. When applying these concepts the underlying assumption of ‘substance over form’ should be followed. This assumption is based on the premise that GHG emissions should be accounted and reported in accordance with the company’s substance and economic reality and not merely its legal form.”

“For the purpose of applying the concepts of ‘control’ and ‘significant influence’ to GHG accounting, the following definitions may prove helpful.”

“*Control* is defined as the ability of a company to direct the operating policies of another entity/facility. Usually, if the company owns more than 50 percent of the voting interests, this implies control. The holder of the operating license often exerts control, however, holding the operating license is not a sufficient criteria for being able to direct the operating policies of an entity/facility. In practice, the actual exercise of dominant influence itself is enough to satisfy the definition of control without requiring any formal power or ability through which it arises.”

“*Significant influence*: the issue of whether a company has significant influence over an entity/facility is likely to have been already established by the company-specific financial accounting and reporting policies/practices. However, where it is necessary to determine if one company exerts significant influence over an entity/facility, the following factors should be considered:

- the company owns voting interests of between 20 and 50 percent
- the company has the power to participate in the entity’s/facility’s financial and operating policy decisions
- the company has a long-term interest in the entity/facility”

“...GHG emissions from entities/facilities that are not under significant influence or control (e.g., the company owns less than 20 percent of the voting interests) are generally not reported. This is consistent with financial accounting standards where a company would only recognize revenue if dividends were paid or a loss incurred if the asset was impaired. However, it is recognized that GHG emissions are different in their nature and it may be appropriate for these to be reported to properly reflect the company’s overall GHG emissions. If this is the case it is important to state this in the public report.”

“Companies should preferably account for and report their GHG emissions according to the framework presented in [the following table]. This framework is set out to provide GHG emissions information in a transparent manner on the basis of control/influence and equity share basis. Equity share is defined as the percentage of economic interest in/benefit derived from an operation. This approach increases the usability of GHG information for

different users and aims, as far as possible, to mirror the approach adopted by financial accounting and reporting standards.”

“Where there is a contractual arrangement that covers GHG emissions, the company should defer to this for the purposes of emissions allocation.”

“...What constitutes ‘control’ and ‘significant influence’ may not always be obvious. The definitions provided by different financial accounting and reporting standards such as the International Accounting Standards (IAS) and US Generally Accepted Accounting Principles (US GAAP) do not always converge. Therefore, when accounting for GHG emissions from partially-owned entities/facilities you should follow, as closely as possible, the distinctions of ‘control’ and ‘significant influence’ as applied by your company for the financial consolidation of such entities/facilities.”

“...GHG emissions reduction initiatives, and regulatory and trading schemes often focus on control rather than ownership. The company holding the operating license might be asked to report 100 percent of the operations’ GHG emissions. It is therefore important to distinguish between operations controlled on the basis of the operating license and those controlled on the basis of majority voting interest or other reasons.”

The WRI/WBCSD Protocol recommends that where possible, companies report emissions using both the equity share and control/influence methods to allocate emissions from partially owned sources. The allocation recommendations are summarized in the following table (WRI 2001a). The WRI/WBCSD report contains several examples of how to allocate emissions based on control/influence and equity share.

Table 3. Accounting for GHG Emissions on the Basis of Control and Equity Share
(Table 1 from WRI 2001a)

Category	What to Report	
Reporting for Control		
Controlled entities/facilities Emissions from those entities/facilities, which are defined as being controlled. It is likely that this will already be determined by company-specific financial accounting policies/practices. This category includes entities/facilities that are: <ul style="list-style-type: none">• wholly owned• not wholly owned, but controlled• jointly controlled assets/entities The concept of jointly controlled assets/entities will have to be considered based on the specific business and industry context.	Wholly owned Not wholly owned but controlled Jointly controlled	100% of GHG emissions 100% of GHG emissions Equity share of GHG emissions
Reporting for Equity Share		
A. Controlled entities/facilities Emissions from those entities/facilities, which are defined as being controlled. It is likely that this will already be determined by company-specific financial accounting policies/practices. This category includes entities/facilities that are: <ul style="list-style-type: none">• wholly owned• not wholly owned, but controlled• jointly controlled assets/entities	Equity share of GHG emissions If there is a specific contractual arrangement that covers the division of earnings/production, that arrangement should be considered. This is likely to be most prominent in the upstream oil and gas industry, and is determined by company-specific financial accounting policies/practices.	
B. Significant influence – associated entities/facilities Emissions from entities/facilities over which the reporting company has significant influence but does not control. It is likely that this will already be determined by company specific financial accounting policies/practices.	Equity share of GHG emissions If there is a specific contractual arrangement that covers the division of earnings/production, that arrangement should be considered. This is likely to be most prominent in the upstream oil and gas industry, and is determined by company-specific financial accounting policies/practices.	
Equity share of GHG emissions	Equity share of GHG emissions from entities/facilities that are controlled or under significant influence (A + B)	

ANNEX I

SUPPORTING INFORMATION

1.0 ESTIMATES OF CLIMATE-NEUTRAL CO₂ EMISSIONS FROM BIOMASS COMBUSTION

Pulp and paper mills generate approximately two thirds of their energy needs from greenhouse gas-neutral 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 CO₂ emitted during the manufacturing and combustion processes is the atmospheric carbon dioxide that was sequestered during growth of the tree; hence, there is no net contribution to the atmospheric CO₂ level. This carbon cycle is a closed-loop. New tree growth keeps absorbing atmospheric carbon dioxide and maintains the cycle.

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

1.1 Estimated Biomass Emissions

The information reported below on biomass emissions is being supplied:

- To ensure that readers understand the entity's overall energy profile in terms of both greenhouse gas emissions and non-greenhouse gas emissions, and
- To provide awareness and understanding of how greenhouse-gas-neutral biomass fuels are generated and used in the manufacture of pulp and paper.

Tables 1 through 3 on the following pages can be used to estimate emissions of climate-neutral CO₂ emissions from biomass combustion and Table 4 can be used to record the results.

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

Table 3. Suggested pulping liquor default emission factors for climate-neutral CO₂
- includes emissions from both the recovery furnace and lime kiln/calcliner -

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]	Climate-neutral CO ₂ Emission Factor [kg CO ₂ / GJ LHV]
Kraft black liquor*	Scandinavian Softwood	35	14.2	13.5	89.9
Kraft black liquor*	Scandinavian Hardwood	32.5	13.5	12.8	87.8
Kraft black liquor*	North American Softwood	35	14.2	13.5	89.9
Kraft black liquor*	North American Hardwood	34	13.9	13.2	89.2
Kraft black liquor*	Tropical Eucalyptus	34.8			
Kraft black liquor*	Tropical Mixed Woods	35.2	14.1	13.4	91.1
Kraft black liquor*	Bagasse	36.9	14.8	14.1	90.9
Kraft black liquor*	Bamboo	34.5	14.1	13.4	89.2
Kraft black liquor*	Straw	36.5	14.7	14.0	90.6
Semi-Chemical					to be determined
Sulfite					to be determined
* kraft black liquor default emission factors are from: Chapter 1- Chemical Recovery, by Esa Vakkilainen. 1999. In: <i>Papermaking Science and Technology, Book 6B: Chemical Pulping</i> . Gullichsen, J., and Paulapuro, H. (eds.). Helsinki, Finland: Fapet Oy					

Table 4. Direct Emissions of Climate-neutral CO₂ from Biomass

<p><i>Write “NA” to show an item is not applicable.</i></p> <p><i>Where emissions have been determined to be insignificant or non-material, write “NM” and explain the basis for the determination in a footnote.</i></p>		<p>Direct Emissions of Climate-neutral CO₂</p> <p>– metric tons -</p>
1	Biomass– fueled boilers (from Table 1 in Annex I)	
2	Pulping liquor-derived CO ₂ (from Table 2 in Annex I)	
3	Total Direct Emissions of Climate-neutral CO ₂ (Sum of line 1 and 2)	
<p>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.</p>		
<p>Include any other information that is needed to understand the inventory results:</p>		

ANNEX J

REFERENCES FOR ANNEXES A THROUGH H

AEA Technology. 2001. *UK Greenhouse Gas Inventory 1990-1999: Annual Report for submission under the Framework Convention on Climate Change*. National Environmental Technology Centre. Oxfordshire, England.
<http://ariadne.aeat.co.uk/netcen/airqual/reports/ghg/ghg2.html> (26 Nov. 2001)

Australian Greenhouse Office (AGO). 1998. *Energy Workbook for Fuel Combustion Activities (Stationary Sources) – Workbook 1.1 with Supplements - 1998*. Australian Greenhouse Office. Canberra, Australia;
<http://www.greenhouse.gov.au/inventory/methodology/98workbook1.pdf> (26 Nov. 2001)

Australian Greenhouse Office (AGO). 1999. *Workbook for Fuel Combustion Activities (Stationary Sources) – Workbook 1.1 – 1999 Supplement*. Australian Greenhouse Office. Canberra, Australia.
<http://www.greenhouse.gov.au/inventory/inventory/pdfs/methodstat99.pdf> (26 Nov. 2001)

Australian Greenhouse Office (AGO). 2001a. *National Greenhouse Gas Inventory – 1999*. Australian Greenhouse Office. Canberra, Australia.
http://www.greenhouse.gov.au/inventory/inventory/latest_inventory.html (26 Nov. 2001)

Australian Greenhouse Office (AGO). 2001b. *Greenhouse Challenge – Factor and Methods Workbook, Version 3 – December 2001*. Australian Greenhouse Office, Canberra, Australia,
<http://www.greenhouse.gov.au/challenge/html/member-tools/factorsmethod.html> (15 Feb. 2002)

Australian Paper Industry Council (APIC). 2002. *Environmental Performance Indicators*.
<http://www.apic.asn.au/environment/default.htm> (15 Feb. 2002)

Axelsson, L. 2001. *Personal communication between Lars-Erik Axelsson of the Swedish Forest Industries Federation and Reid Miner, NCASI*. September 2001

Barnard, G. 2001. *Personal communication between Graham Barnard of the Paper Federation of Great Britain and Reid Miner of NCASI*. September 2001

Canada's Climate Change Voluntary Challenge and Registry Inc. (VCR). 1999. *Registration Guide 1999 – Canada's Climate Change Voluntary Challenge and Registry Inc.*
http://www.vcr-mvr.ca/Downloads/PDF/VCR-RegistrationGuide_e.pdf (26 Nov. 2001)

Centre Interprofessionnel Technique d'Etudes de la Pollution Atmosphérique (CITEPA). 2000. *Inventaire des émissions des gaz à effet de serre en France de 1990 à 1999*. Centre Interprofessionnel Technique d'Etudes de la Pollution Atmosphérique. Paris, France.
http://www.citepa.org/emissions/france_objectifs/Emissions_France_Ipcc_2000.pdf (26 Nov. 2001)

Chilean National Environmental Commission. 1999. *First National Communication to the Conference of the Parties to the United Nations Framework Convention on Climate Change*. Chilean National Environmental Commission. Santiago, Chile.
<http://www.unfccc.de/resource/docs/natc/chinc1.pdf> (26 Nov. 2001)

Environment Canada. 1999. *Canada's Greenhouse Gas Inventory – 1997 Emissions and Removals with Trends*. Environment Canada. Ottawa, Canada.
http://www.ec.gc.ca/pdb/ghg/ghg_docs/gh_eng.pdf (26 Nov. 2001)

European Environment Agency (EEA). 1999. *EMEP/CORINAIR Atmospheric emission inventory guidebook - Second edition*. Copenhagen, Denmark.
<http://reports.eea.eu.int/EMEPCORINAIR/en> (26 Nov. 2001)

Finnish Forest Industries Federation. 2001. *Environmental Report – Statistics for 2000*.
www.forestindustries.fi/index_2.htm (26 Nov. 2001)

Forest Products Association of Canada (FPAC). 2001. *2001 Greenhouse Gas Action Plan Guidelines*. Forest Products Association of Canada. Montreal, Canada

Fortum Power and Heat Oy (Fortum). 2001. *Methane and Nitrous Oxide Emissions in the Finnish Energy Production*. Fortum Power and Heat Oy. Fortum, Finland, Technology

Hough, G.. 1985. *Chemical Recovery in the Alkaline Pulping Processes*. TAPPI Press. Atlanta GA

International Energy Agency (IEA). 1998. *The Role of Bioenergy in Greenhouse Gas Mitigation*. International Energy Agency. Paris.
http://www.ieabioenergy.com/media/6_pospapa4.pdf (14 Feb. 2002)

Intergovernmental Panel on Climate Change (IPCC). 1997a. *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reporting Instructions (Volume 1)*. IPCC National Greenhouse Gas Inventory Program. <http://www.ipcc-nggip.iges.or.jp/public/gl/invs4.htm> (26 Nov. 2001)

Intergovernmental Panel on Climate Change (IPCC). 1997b. *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Workbook (Volume 2)*. IPCC National Greenhouse Gas Inventory Program. <http://www.ipcc-nggip.iges.or.jp/public/gl/invs5.htm> (26 Nov. 2001)

Intergovernmental Panel on Climate Change (IPCC). 1997c. *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories: Reference Manual (Volume 3)*. IPCC National Greenhouse Gas Inventory Program. <http://www.ipcc-nggip.iges.or.jp/public/gl/invs6.htm> (26 Nov. 2001)

Intergovernmental Panel on Climate Change (IPCC). 2000. *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*. IPCC National Greenhouse Gas Inventory Program.

<http://www.ipcc-nggip.iges.or.jp/public/gp/gpgaum.htm> (26 Nov. 2001)

Japan Paper Association (JPA). 2001. *Various personal communications between Masao Taniguchi of JPA and Reid Miner of NCASI*. Japan Paper Association. Tokyo Japan

Karessuo, A. 2001. *Personal Communication between Anu Karessuo of the Finnish Forest Industries Federation and Reid Miner of NCASI*. September 2001

Miner, R. and Upton, B.. 2002. Methods for estimating greenhouse gas emissions from lime kilns at kraft pulp mills. *Energy*, Volume 27 No. 8, pp. 729-738 (Sept. 2002) Elsevier Science, New York, NY

National Council for Air and Stream Improvement (NCASI). 1980. *A Study of Wood-Residue Fired Power Boiler Total Gaseous Non-Methane Organic Emissions in the Pacific Northwest - Air Quality Technical Bulletin No.109*. NCASI. Research Triangle Park, NC

National Council for Air and Stream Improvement (NCASI). 1981. *A Study of the Kraft Process Lime Kiln Total Gaseous Non-Methane Organic Emissions - Technical Bulletin No. 358*. NCASI. Research Triangle Park, NC

National Council for Air and Stream Improvement (NCASI). 1985. *Volatile Organic Carbon Emissions from Wood Residue Fired Power Boilers in the Southeast - Technical Bulletin No.455*. NCASI. Research Triangle Park, NC

National Council for Air and Stream Improvement (NCASI). 1999. *Evaluation of the EPA-Recommended Approach to Predicting Air Emissions from Pulp and Paper Landfills - Technical Bulletin No.790*. NCASI. Research Triangle Park, NC

Pulp and Paper Manufacturers Federation of Australia (PPMFA). 2001. *Australian Pulp and Paper Industry Environmental Performance Indicators Survey Form*. Pulp and Paper Manufacturers Federation of Australia. Manuka. Australia

Swedish Environmental Protection Agency. 2001. *Sweden's National Inventory Report 2001 – Submitted under the United National Convention on Climate Change*. Swedish Environmental Protection Agency. Stockholm, Sweden.
<http://www.environ.se/dokument/fororen/klimat/klimat/fccdata/NIR2001.pdf> (26 Nov. 2001)

Technical Research Center of Finland. 2001. *Greenhouse Gas Emissions and Removals in Finland*. Technical Research Center of Finland. Espoo, Finland.
<http://www.vyh.fi/eng/environ/state/air/emis/ghg/methodol.htm> (26 Nov. 2001)

United States Department of Energy (USDOE). 2000. *General Guidelines and Supporting Documents Establishing the Voluntary Reporting of Greenhouse Gases Program*. US Department of Energy. Energy Information Administration. Washington D.C. <http://www.eia.doe.gov/oiaf/1605/guidelns.html> (26 Nov. 2001)

United States Department of Energy (USDOE). 2001a. *Updated State-level Greenhouse Gas Emission Factors for Electricity Generation*. US Department of Energy. Energy Information Administration. Washington, D.C. <ftp://ftp.eia.doe.gov/pub/oiaf/1605/cdrom/pdf/e-supdoc.pdf> (26 Nov. 2001)

United States Department of Energy (USDOE). 2001b. *Average Electricity Emission Factors by State*. US Department of Energy. Energy Information Administration. Washington, D.C. <http://www.eia.doe.gov/oiaf/1605/e-factor.html> (26 Nov. 2001)

United States Environmental Protection Agency (USEPA). 1993. *Anthropogenic Methane Emissions in the United States: Estimates for 1990, Report to Congress*. EPA 430-R-93-003. United States Environmental Protection Agency. Washington, D.C.

United States Environmental Protection Agency (USEPA). 1998. *AP-42 Emission Factors for Municipal Solid Waste Landfills – Supplement E, November 1998*. United States Environmental Protection Agency. Washington, D.C. <http://www.epa.gov/ttn/chief/ap42/ch02/final/c02s04.pdf> (26 Nov. 2001)

United States Environmental Protection Agency (USEPA). 2001a. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-1999*. EPA 236-R-01-001. United States Environmental Protection Agency. Washington, D.C. <http://www.epa.gov/globalwarming/publications/emissions/us2001/index.html> (26 Nov. 2001)

United States Environmental Protection Agency (USEPA). 2001b. *AP-42 Emission Factors for Wood Residue Combustion in Boilers – Supplement G, July 2001*. United States Environmental Protection Agency. Washington, D.C. <http://www.epa.gov/ttn/chief/ap42/ch01/final/c01s06.pdf> (26 Nov. 2001)

World Resources Institute (WRI) and World Business Council for Sustainable Development. 2001a. *The Greenhouse Gas Protocol: a corporate accounting and reporting standard*. World Resources Institute. Washington, D.C. <http://www.ghgprotocol.org/standard/ghg.pdf> (26 Nov. 2001)

World Resources Institute (WRI) and World Business Council for Sustainable Development. 2001b. *Calculating CO₂ emissions from the combustion of standard fuels and from electricity/steam purchase - Guide to calculation worksheets*. World Resources Institute. Washington, D.C. <http://www.ghgprotocol.org/standard/stationarycombustion.doc> (26 Nov. 2001)

World Resources Institute (WRI) and World Business Council for Sustainable Development.
2001c. *Calculating CO₂ emissions from the combustion of standard fuels and from electricity/steam purchase - Calculation worksheets*. World Resources Institute. Washington, D.C. <http://www.ghgprotocol.org/standard/stationarycombustion.xls> (26 Nov. 2001)

World Resources Institute (WRI) and World Business Council for Sustainable Development.
2001d. *Calculating CO₂ emissions from Mobile Sources -Guide to calculation worksheets*. World Resources Institute. Washington, D.C.
<http://www.ghgprotocol.org/standard/mobile.doc> (26 Nov. 2001)