



Australian Government
Department of Climate Change

NATIONAL GREENHOUSE ACCOUNTS (NGA) FACTORS



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thinkchange

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Table of Contents

1	Key definitions and terms	6
2	Energy	10
3	Industrial processes including use of synthetic gases	32
4	Waste emissions.....	41
5	Agriculture.....	46
6	Land-use change and forestry (vegetation sinks)	48
	Appendix 1 Greenhouse Gas Global Warming Potentials.....	51
	Appendix 2 Units and conversions.....	52
	Appendix 3 Carbon content factors for fuels.....	54
	Appendix 4 Scope 3 emission factors	57
	Appendix 5 revised factors from November 2008.....	66

List of Tables

Table 1: Fuel combustion emission factors - solid fuels and certain coal based products	11
Table 2: Emission factors for the consumption of natural gas	13
Table 3: Fuel combustion emission factors - liquid fuels and certain petroleum based products for stationary energy purposes	15
Table 4: Fuel combustion emission factors -fuels used for transport energy purposes.....	17
Table 5: Indirect (scope 2) emission factors for consumption of purchased electricity from the grid.....	19
Table 6: Emission factors for the extraction of coal (fugitive)- Underground	20
Table 7: Post-mining activities—emission factors	20
Table 8: Emission factors for the production of coal (fugitive)- Open cut.....	21
Table 9: Oil and gas exploration emission factors.....	23
Table 10: Oil production (other than venting and flaring) emission factors.....	23
Table 11: Crude oil production (flared emissions) emission factors.....	24
Table 12: Oil transport emission factors	26
Table 13: Oil refining and storage emission factors	27
Table 14: Refinery gas flaring emission factors	27
Table 15: Natural gas production and processing (other than emissions that are vented or flared) emission factors.....	28
Table 16: Natural gas transmission emission factors.....	29
Table 17: Natural gas combustion emission factors and unaccounted for gas factors.....	30
Table 18: Flaring emission factors.....	31
Table 19: Clinker production emission factors	32
Table 20: Lime production emission factors.....	33
Table 21: Calcination of carbonates emission factors.....	34
Table 22: Soda ash consumption emission factor.....	34
Table 23: Nitric acid production emission factors.....	35
Table 24: Aluminium perfluorinated carbon compound emission factors	39
Table 25: Leakage rates for synthetic gases.....	40
Table 26: Default industrial wastewater treatment parameters by commodity type.....	43
Table 27: Global Warming Potentials	51
Table 28: Metric prefixes	52
Table 29: Unit equivalences	52
Table 30: Energy conversion factors	53
Table 31: Table Municipal solid waste volume to weight conversion factors.....	53
Table 32: Carbon content factors - Solid fuels and certain coal based products.....	54
Table 33: Carbon content factors - Gaseous fuels.....	55

Table 34: Carbon content factors - Liquid fuels and certain petroleum based products	55
Table 35: Carbon content factors - Petroleum feedstocks and products	56
Table 36: Scope 3 emission factors –solid fuels and certain coal based products.....	58
Table 37: Scope 3 emission factors – consumption of natural gas.....	58
Table 38: Scope 3 emission factors – liquid fuels and certain petroleum based products	58
Table 39: Scope 2 and 3 emissions factors - consumption of purchased electricity by end users	59
Table 40: Waste mix methane conversion factors	62
Table 41: Waste variables and default values.....	63
Table 42: Waste emission factors for total waste disposed to landfill by broad waste stream category	63
Table 43: Municipal waste variables and default values	65

Introduction

The *National Greenhouse Accounts (NGA) Factors* has been prepared by the Department of Climate Change and is designed for use by companies and individuals to estimate greenhouse gas emissions for reporting under various government programs and for their own purposes.

Unless otherwise stated, the methods for calculating emissions listed in this document are "Method 1" from the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* and the *National Greenhouse and Energy Reporting (Measurement) Technical Guidelines June 2009*. The *Technical Guidelines* are available on the Department of Climate Change website and have been designed to support reporting under the *National Greenhouse and Energy Reporting Act 2007*.

While drawing on the *National Greenhouse and Energy Reporting (Measurement) Determination 2008*, the methods described here in the *NGA Factors* have a general application to the estimation of a broader range of greenhouse emissions inventories.

The default emission factors listed have been estimated by the Department of Climate Change using the Australian Greenhouse Emissions Information System (AGEIS) and are determined simultaneously with the production of Australia's National Greenhouse Accounts. This ensures that consistency is maintained between inventories at company or facility level and the emission estimates presented in the National Greenhouse Accounts. The emission factors are referred to in this document as National Greenhouse Accounts (NGA) default emission factors.

More information on the estimation methods employed in the National Greenhouse Accounts is available in the *National Inventory Report 2007*. The methods used at the national level, and reflected in the factors reported here, are consistent with international guidelines and are subject to international expert review each year.

Reporters under the National Greenhouse and Energy Reporting System may utilise NGA default emission factors listed in the *Technical Guidelines* in the preparation of emission inventories or they may choose to utilise information on emission factors available at facility level, under certain conditions. Guidance is provided to assist Reporters that choose to use their own information on emission factors. See the *Technical Guidelines* for more details.

The emission factors reported in this publication replace those listed in the *NGA Factors*, released in November 2008. Updated factors and methods in this document correspond to those detailed in the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* and the *National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2009 (No. 1)*.

Past published emission factors reflected the best information available at the time of their release and may remain valid for particular programs. Updates to emission factors for past years presented in this document do not necessarily imply any need to revise estimates of emissions for previous years - approaches to updating past emission estimates will depend on the particular details of individual greenhouse reporting programs.

1 Key definitions and terms

1.1 Direct and indirect emissions

Direct emissions are produced from sources within the boundary of an organisation and as a result of that organisation's activities. These emissions mainly arise from the following activities:

- generation of energy, heat, steam and electricity, including carbon dioxide and products of incomplete combustion (methane and nitrous oxide);
- manufacturing processes which produce emissions (for example, cement, aluminium and ammonia production);
- transportation of materials, products, waste and people; for example, use of vehicles owned and operated by the reporting organisation;
- fugitive emissions: intentional or unintentional GHG releases (such as methane emissions from coal mines, natural gas leaks from joints and seals); and
- on-site waste management, such as emissions from landfill sites.

For example, a company with a car fleet would report greenhouse gas emissions from the combustion of petrol in those motor vehicles as direct emissions. Similarly, a mining company would report methane escaping from a coal seam during mining (fugitive emissions) as direct emissions and a cement manufacturer would report carbon dioxide released during cement clinker production as direct emissions.

Emission factors for calculating direct emissions are generally expressed in the form of a quantity of a given GHG emitted per unit of energy (kg CO₂-e /GJ), fuel (t CH₄/t coal) or a similar measure. Emission factors are used to calculate GHG emissions by multiplying the factor (e.g. kg CO₂/GJ energy in petrol) with activity data (e.g. kilolitres x energy density of petrol used). In this workbook, emission factors are provided as applicable, for each of the following greenhouse gases:

- carbon dioxide
- methane
- nitrous dioxide
- synthetic gases
 - HFCs, SF₆, CF₄, C₂F₆

All factors are standardised by being expressed as a carbon dioxide equivalent (CO₂-e). This is achieved by multiplying the individual gas emission factor by the respective gas global warming potential (GWP). The GWPs for each gas are listed in Table 27, Appendix 1.

Indirect emissions are emissions generated in the wider economy as a consequence of an organisation's activities (particularly from its demand for goods and services), but which are physically produced by the activities of another organisation. The most important category of indirect emissions is from the consumption of electricity. Other examples of indirect emissions from an organisation's activities include upstream emissions generated in the extraction and

production of fossil fuels, downstream emissions from transport of an organisation's product to customers, and emissions from contracted/outsourced activities. The appropriate emission factor for these activities depends on the parts of upstream production and downstream use considered in calculating emissions associated with the activity.

1.2 Types of emission factors

The world of emission factors can become confusing—the following is provided to clarify the purpose of the types of emissions factors in this workbook.

Firstly, it is important to note that an emission factor is activity-specific. The activity determines the emission factor used. The scope that emissions are reported under is determined by whether the activity is within the organisation's boundary (direct—scope 1) or outside it (indirect—scope 2 and scope 3).

- **Direct (or point-source) emission factors** give the kilograms of carbon dioxide equivalent (CO₂-e) emitted per unit of activity at the point of emission release (i.e. fuel use, energy use, manufacturing process activity, mining activity, on-site waste disposal, etc.). These factors are used to calculate **scope 1 emissions**.
- **Indirect emission factors** are used to calculate **scope 2 emissions** from the generation of the electricity **purchased and consumed** by an organisation as kilograms of CO₂-e per unit of electricity consumed. Scope 2 emissions are physically produced by the burning of fuels (coal, natural gas, etc.) at the power station.
- **Various emission factors** can be used to calculate **scope 3 emissions**. For ease of use, this workbook reports **specific 'scope 3' emission factors** for organisations that:
 - (a) burn fossil fuels: to estimate their indirect emissions attributable to the extraction, production and transport of those fuels; or
 - (b) consume purchased electricity: to estimate their indirect emissions from the extraction, production and transport of fuel burned at generation and the indirect emissions attributable to the electricity lost in delivery in the T&D network.

The definition, methodologies and application of scope 3 factors are currently subject to international discussions. Available scope 3 emission factors are listed in Appendix 4. Scope 3 factors and methods are also provided for companies wishing to estimate their scope 3 emissions from disposal of waste generated (e.g. if the waste is transported outside the organisation and disposed of).

1.3 Information sources

The principle sources of information used in developing this workbook include:

Australian Bureau of Agricultural and Resource Economics (2007) Fuel and Electricity Survey – Fuel Codes, www.abareconomics.com/publications_html/surveys/surveys/surveys.html, Commonwealth of Australia, Canberra.

Australian Bureau of Agricultural and Resource Economics (2007) Energy in Australia 2006, produced for Department of Industry, Tourism and Resources, pages 77-79, Commonwealth of Australia, Canberra.

NATIONAL GREENHOUSE ACCOUNTS (NGA) FACTORS

American Petroleum Institute (2004) *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry 2004*.

Australian Greenhouse Office (2006), *AGO Generator Efficiency Standards - Technical Guidelines*, December 2006, Commonwealth of Australia, Canberra.

Energy Supply Association of Australia (2008), *Electricity, Gas Australia 2008*.

Intergovernmental Report on Climate Change (2006), *2006 IPCC Guidelines for National Greenhouse Gas Inventories*; Japan.

Intergovernmental Report on Climate Change (2000), *Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories*, Japan

Intergovernmental Report on Climate Change (1997), *1996 IPCC Guidelines for National Greenhouse Gas Inventories*; Japan.

International Aluminium Institute (2006), *The Aluminium Sector Greenhouse Gas Protocol, Addendum to the WRI/WBCSD GHG Protocol*.

International Energy Agency (2005), *Energy Statistics Manual*, 2005, Paris.

Department of Climate Change (2009a), *National Inventory Report 2007*, Commonwealth of Australia, Canberra.

Department of Climate Change (2009b), *National Greenhouse and Energy Reporting (Measurement) Technical Guidelines June 2009*, Department of Climate Change, Commonwealth of Australia, Canberra.

Department of Climate Change (2008a), *National Greenhouse Accounts Factors*, November 2008, Commonwealth of Australia, Canberra.

Department of Climate Change (2008b), *National Greenhouse and Energy Reporting (Measurement) Determination 2008*, Commonwealth of Australia, Canberra.

US EPA, International Aluminium Institute (2003), *Protocol for Measurement of Tetrafluoromethane (CF₄) and Hexafluoroethane (C₂F₆) Emissions from Primary Aluminium Production*.

World Business Council for Sustainable Development / World Resources Institute, *The Greenhouse Gas Protocol, A Corporate Accounting and Reporting Standard*, Revised edition.

World Business Council for Sustainable Development, (2005), *CO₂ Accounting and Reporting Standard for the Cement Industry- The Cement CO₂ Protocol*, June 2005.

Wilkenfeld, George, and Associates Pty Ltd (2007), *Australia's National Greenhouse Gas Inventory, 1990, 1995, 2000 and 2005 End Use Allocation of Energy Emissions*, report to the Department of Climate Change, Commonwealth of Australia, Canberra.

Wilkenfeld, George, and Associates Pty Ltd (2008), *Australia's National Greenhouse Gas Inventory: 2007 Electricity Sector Emissions*, internal report to the Department of Climate Change, Commonwealth of Australia, Canberra.

Wilkenfeld, George and Pit & Sherry (2009), *Review of scope 3 emission factors for natural gas and its components*, internal report to the DCC.

1.4 Additional information and web sites

Australian National Greenhouse Gas Accounts and related topics

www.climatechange.gov.au/inventory/index.html

Intergovernmental Panel on Climate Change (IPCC) National Greenhouse Gas Inventories Program

www.ipcc-nggip.iges.or.jp

National Greenhouse and Energy Reporting

<http://www.climatechange.gov.au/reporting/index.html>

The Online System for Comprehensive Activity Reporting (OSCAR)

<http://www.climatechange.gov.au/oscar/index.html>

United Nations Convention on Climate Change and related topics including the Kyoto Protocol

www.unfccc.int

The Greenhouse Gas Protocol Initiative (convened by the World Business Council for Sustainable Development (WBCSD) and the World Resources Institute (WRI))

www.ghgprotocol.org

1.5 Contacts

For enquiries relating to this Workbook

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Tel: 02 6159 7000

For enquiries relating to National Greenhouse and Energy Reporting

Email: reporting@climatechange.com.au

NGER Office phone 1800 018 831

The Online System for Comprehensive Activity Reporting (OSCAR)

Email: oscar@climatechange.gov.au

1.6 Revisions to factors from previous issue

The following factors have been updated in this workbook:

- Ethane – energy content (Table 2, page 13)
- Electricity – scope 2 and 3 emission factors 2006, and 2007 (Table 39, page 61)
 - New “latest estimate” scope 2 and 3 emission factors have also been provided (Tables 5 and 39, pages 20 and 61)
- Natural Gas – scope 3 emission factors (Table 37, page 60)
- Liquefied Petroleum Gas – scope 3 emission factors (Table 38, page 60)
- Solid Waste – scope 3 conversion factors by waste stream (Table 42, page 65)

Further information about revised factors can be found at Appendix 5.

National Greenhouse Accounts (NGA) Factors

2 Energy

This section addresses the estimation of emissions in the energy sector and includes emission factors for:

- the stationary combustion of solid, gaseous and liquid fuels (section 2.1);
- the combustion of liquid and gaseous fuels for transport (section 2.2);
- the consumption of purchased electricity (section 2.3); and
- the extraction of fossil fuels (section 2.4).

The approach to calculating GHG emissions may depend on the program or purpose for which they are being used and this should be confirmed with the program's administrators, if necessary, prior to estimation.

The principle greenhouse gas generated by the combustion of fossil fuels for energy is carbon dioxide. The quantity of gas produced depends on the carbon content of the fuel and the degree to which the fuel is fully combusted (i.e. the oxidation factor, which usually ranges between 98% and 99.5%). Small quantities of methane and nitrous oxide are also produced, depending on the actual combustion conditions. Methane may be generated when fuel is heated, but only partially burnt, and depends on combustion temperatures and the level of oxygen present. Nitrous oxide results from the reaction between nitrogen and oxygen in the combustion air.

2.1 Stationary energy emissions (non-transport)

Estimates of emissions from the combustion of individual fuel types are made by multiplying a (physical) quantity of fuel combusted by a fuel-specific energy content factor and a fuel-specific emission factor. This is performed for each relevant greenhouse gas (in this case, carbon dioxide, methane and nitrous oxide). Separate calculations should be carried out for each fuel type.

Total greenhouse emissions are calculated by summing the emissions of each fuel type and each greenhouse gas.

2.1.1 Fuel combustion emissions – solid fuels

The following formula can be used to estimate greenhouse gas emissions from the combustion of each type of fuel listed in Table 1.

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ijoxec}}{1\ 000}$$

NATIONAL GREENHOUSE ACCOUNTS (NGA) FACTORS

where:

E_{ij} is the emissions of gas type (j), (carbon dioxide, methane or nitrous oxide), from fuel type (i) (CO₂-e tonnes).

Q_i is the quantity of fuel type (i) (tonnes).

EC_i is the energy content factor of the fuel (gigajoules per tonne) according to each fuel in Table 1.

If Q_i is measured in gigajoules, then EC_i is 1.

EF_{ijoxec} is the emission factor for each gas type (j) (which includes the effect of an oxidation factor) for fuel type (i) (kilograms of CO₂-e per gigajoule) according to each fuel in Table 1.

Table 1: Fuel combustion emission factors - solid fuels and certain coal based products

Fuel combusted	Energy content factor GJ/t	Emission factor kg CO ₂ -e/GJ (relevant oxidation factors incorporated)		
		CO ₂	CH ₄	N ₂ O
Black coal (other than that used to produce coke)	27.0	88.2	0.03	0.2
Brown coal	10.2	92.7	0.01	0.4
Coking coal	30.0	90.0	0.02	0.2
Brown coal briquettes	22.1	93.3	0.06	0.3
Coke oven coke	27.0	104.9	0.03	0.2
Coal tar	37.5	81.0	0.02	0.2
Solid fossil fuels other than those mentioned in the items above	22.1	93.3	0.06	0.3
Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	26.3	79.9	0.02	0.2
Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	10.5	85.4	0.6	1.2
Dry wood	16.2	0.0	0.08	1.2
Green and air dried wood	10.4	0.0	0.08	1.2
Sulphite lyes	12.4	0.0	0.06	0.6
Bagasse	9.6	0.0	0.2	1.3
Biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	12.2	0.0	0.6	1.2
Charcoal	31.1	0.0	4.0	1.2
Primary solid biomass fuels other than those mentioned in the items above	12.2	0.0	0.6	1.2

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Schedule 1)

Notes: All emission factors incorporate relevant oxidation factors (sourced from the DCC's National Inventory Report).

Note Energy content and emission factors for coal products are measured on an as fired basis. Black coal represents coal for uses other than electricity and coking. The energy content for black coal and coking coal (metallurgical coal) is on a washed basis.

Example: calculation of emissions from black coal consumption

A facility consumes 20,000 tonnes of black coal for a purpose other than for the production of electricity or coke.

Emissions of greenhouse gases (carbon dioxide, methane and nitrous oxide) in tonnes of CO₂-e are estimated as follows:

Emissions of carbon dioxide:

$$= (20,000 \times 27.0 \times 88.2)/1,000$$

$$= 47,628 \text{ t CO}_2\text{-e}$$

Emissions of methane:

$$= (20,000 \times 27.0 \times 0.03)/1,000$$

$$= 16 \text{ t CO}_2\text{-e}$$

Emissions of nitrous oxide:

$$= (20,000 \times 27.0 \times 0.2)/1,000$$

$$= 108 \text{ t CO}_2\text{-e}$$

$$\text{Total scope 1 GHG emissions} = 47,628 + 16 + 108$$

$$= 47,752 \text{ t CO}_2\text{-e}$$

2.1.2 Fuel combustion emissions – gaseous fuels

The following formula can be used to estimate greenhouse gas emissions from the combustion of each type of fuel listed in Table 2.

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ijoxec}}{1\,000}$$

where:

E_{ij} is the emissions of gas type (j), (carbon dioxide, methane or nitrous oxide), from gaseous fuel type (i) (CO₂-e tonnes).

Q_i is the quantity of fuel type (i) (cubic metres)

EC_i is the energy content factor of fuel type (i) (gigajoules per cubic metre according to Table 2).

If Q_i is measured in gigajoules, then EC_i is 1.

NATIONAL GREENHOUSE ACCOUNTS (NGA) FACTORS

EF_{ijoxec} is the emission factor for each gas type (j) (which includes the effect of an oxidation factor) for fuel type (i) (kilograms CO₂-e per gigajoule of fuel type (i) according to Table 2).

Table 2: Emission factors for the consumption of natural gas

Fuel combusted	Energy content factor (GJ/m ³ unless otherwise indicated)	Emission factor kg CO ₂ -e/GJ (relevant oxidation factors incorporated)		
		CO ₂	CH ₄	N ₂ O
Natural gas distributed in a pipeline	39.3 × 10 ⁻³	51.2	0.1	0.03
Coal seam methane that is captured for combustion	37.7 × 10 ⁻³	51.1	0.2	0.03
Coal mine waste gas that is captured for combustion	37.7 × 10 ⁻³	51.6	5.0	0.03
Compressed natural gas (reverting to standard conditions)	39.3 × 10 ⁻³	51.2	0.1	0.03
Unprocessed natural gas	39.3 × 10 ⁻³	51.2	0.1	0.03
Ethane	62.9 × 10 ⁻³	56.2	0.02	0.03
Coke oven gas	18.1 × 10 ⁻³	36.8	0.03	0.06
Blast furnace gas	4.0 × 10 ⁻³	232.8	0.02	0.03
Town gas	39.0 × 10 ⁻³	59.9	0.03	0.03
Liquefied natural gas	25.3 GJ/kL	51.2	0.1	0.03
Gaseous fossil fuels other than those mentioned in the items above	39.3 × 10 ⁻³	51.2	0.1	0.03
Landfill biogas that is captured for combustion (methane only)	37.7 × 10 ⁻³	0.0	4.8	0.03
Sludge biogas that is captured for combustion (methane only)	37.7 × 10 ⁻³	0.0	4.8	0.03
A biogas that is captured for combustion, other than those mentioned in the items above	37.7 × 10 ⁻³	0.0	4.8	0.03

Sources: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Schedule 1) and *National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2009 (No. 1)*.

Notes: All emission factors incorporate relevant oxidation factors (sourced from the DCC's National Inventory Report).

Example: calculation of emissions from natural gas consumption

A facility consumes 100,000 gigajoules of natural gas.

Emissions of greenhouse gases (carbon dioxide, methane and nitrous oxide) in tonnes of CO₂-e are estimated as follows:

Emissions of carbon dioxide:

$$= (100,000 \times 1 \times 51.2) / 1,000$$

$$= 5,120 \text{ t CO}_2\text{-e}$$

Emissions of methane:

$$= (100,000 \times 1 \times 0.1)/1,000$$

$$= 10 \text{ t CO}_2\text{-e}$$

Emissions of nitrous oxide:

$$= (100,000 \times 1 \times 0.03)/1,000$$

$$= 3 \text{ t CO}_2\text{-e}$$

$$\text{Total scope 1 GHG emissions} = 5,120 + 10 + 3$$

$$= 5,133 \text{ t CO}_2\text{-e}$$

2.1.3 Fuel combustion emissions – liquid fuels

The following formula can be used to estimate greenhouse gas emissions from the stationary combustion of each type of liquid fuel listed in Table 3.

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ijoxec}}{1\,000}$$

where:

E_{ij} is the emissions of gas type (j), (carbon dioxide, methane or nitrous oxide, from fuel type (i) (CO₂-e tonnes).

Q_i is the quantity of fuel type (i) (kilolitres) combusted for stationary energy purposes

EC_i is the energy content factor of fuel type (i) (gigajoules per kilolitre) for stationary energy purposes, according to Table 3.

If Q_i is measured in gigajoules, then EC_i is 1.

EF_{ijoxec} is the emission factor for each gas type (j) (which includes the effect of an oxidation factor) for fuel type (i) (kilograms CO₂-e per gigajoule) according to Table 3.

NATIONAL GREENHOUSE ACCOUNTS (NGA) FACTORS

Table 3: Fuel combustion emission factors - liquid fuels and certain petroleum based products for stationary energy purposes

Fuel combusted	Energy content factor (GJ/kL unless otherwise indicated)	Emission factor kg CO ₂ -e/GJ (relevant oxidation factors incorporated)		
		CO ₂	CH ₄	N ₂ O
Petroleum based oils (other than petroleum based oil used as fuel, eg lubricants)	38.8	27.9	0.0	0.0
Petroleum based greases	38.8	27.9	0.0	0.0
Crude oil including crude oil condensates	45.3 GJ/t	68.9	0.06	0.2
Other natural gas liquids	46.5 GJ/t	60.4	0.06	0.2
Gasoline (other than for use as fuel in an aircraft)	34.2	66.7	0.2	0.2
Gasoline for use as fuel in an aircraft (avgas)	33.1	66.3	0.2	0.2
Kerosene (other than for use as fuel in an aircraft)	37.5	68.2	0.01	0.2
Kerosene for use as fuel in an aircraft (avtur)	36.8	68.9	0.01	0.2
Heating oil	37.3	68.8	0.02	0.2
Diesel oil	38.6	69.2	0.1	0.2
Fuel oil	39.7	72.9	0.03	0.2
Liquefied aromatic hydrocarbons	34.4	69.0	0.02	0.2
Solvents if mineral turpentine or white spirits	34.4	69.0	0.02	0.2
Liquefied petroleum gas	25.7	59.6	0.1	0.2
Naphtha	31.4	69.0	0.00	0.02
Petroleum coke	34.2 GJ/t	90.8	0.06	0.2
Refinery gas and liquids	42.9 GJ/t	54.2	0.02	0.03
Refinery coke	34.2 GJ/t	90.8	0.06	0.2
Petroleum based products other than mentioned in the items above	34.4	69.0	0.02	0.2
Biodiesel	34.6	0.0	0.06	0.2
Ethanol for use as a fuel in an internal combustion engine	23.4	0.0	0.06	0.2
Biofuels other than those mentioned in the items above	23.4	0.0	0.06	0.2

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Schedule 1)

Notes: All emission factors incorporate relevant oxidation factors (sourced from the DCC's National Inventory Report).

2.2 Transport fuel emissions

Fuels used for transport purposes produce slightly different methane and nitrous oxide emissions than if the same fuels were used for stationary energy purposes. Therefore, separate emission factors are provided in Table 4, to apply where fuels are used for general transport purposes. In addition, a range of optional emission factors are provided in Table 4 for use with post-2004 vehicles and heavy vehicles conforming to Euro design standards.

No transport factors are provided for vehicles not registered for road use. Stationary energy factors for individual fuel types should be used in these cases.

Estimates of emissions from the combustion of individual fuel types are made by multiplying a (physical) quantity of fuel combusted by a fuel-specific energy content factor and a fuel-specific emission factor. This is performed for each relevant greenhouse gas (in this case, carbon dioxide, methane and nitrous oxide). Separate calculations should be carried out for each fuel type.

Total greenhouse emissions are calculated by summing the emissions of each fuel type and each greenhouse gas.

The following formula can be used to estimate greenhouse gas emissions from the combustion of each type of fuel listed in Table 4 used for transport energy purposes.

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ijoxec}}{1\,000}$$

where:

E_{ij} is the emissions of gas type (j), carbon dioxide, methane or nitrous oxide, from fuel type (i) (CO₂-e tonnes).

Q_i is the quantity of fuel type (i) (kilolitres or gigajoules) combusted for transport energy purposes

EC_i is the energy content factor of fuel type (i) (gigajoules per kilolitre or per cubic metre) used for transport energy purposes — see Table 4.

If Q_i is measured in gigajoules, then EC_i is 1.

EF_{ijoxec} is the emission factor for each gas type (j) (which includes the effect of an oxidation factor) for fuel type (i) (kilograms CO₂-e per gigajoule) used for transport energy purposes — see Table 4.

NATIONAL GREENHOUSE ACCOUNTS (NGA) FACTORS

Table 4: Fuel combustion emission factors -fuels used for transport energy purposes

Transport equipment type	Fuel combusted	Energy content factor (GJ/kL unless otherwise indicated)	Emission factor kg CO ₂ -e/GJ (relevant oxidation factors incorporated)		
			CO ₂	CH ₄	N ₂ O
General transport					
	Gasoline (other than for use as fuel in an aircraft)	34.2	66.7	0.6	2.3
	Diesel oil	38.6	69.2	0.2	0.5
	Gasoline for use as fuel in an aircraft	33.1	66.3	0.04	0.7
	Kerosene for use as fuel in an aircraft	36.8	68.9	0.01	0.7
	Fuel oil	39.7	72.9	0.06	0.6
	Liquefied petroleum gas	26.2	59.6	0.6	0.6
	Biodiesel	34.6	0.0	1.2	2.2
	Ethanol for use as fuel in an internal combustion engine	23.4	0.0	1.2	2.2
	Biofuels other than those mentioned in items above	23.4	0.0	1.2	2.2
	Natural gas (light duty vehicles)	39.3×10^{-3} GJ/m ³	51.2	5.5	0.3
	Natural gas (heavy duty vehicles)	39.3×10^{-3} GJ/m ³	51.2	2.1	0.3
Post-2004 vehicles					
	Gasoline (other than for use as fuel in an aircraft)	34.2	66.7	0.02	0.2
	Diesel oil	38.6	69.2	0.01	0.6
	Liquefied petroleum gas	26.2	59.6	0.3	0.3
	Ethanol for use as fuel in an internal combustion engine	23.4	0	0.2	0.2
Heavy vehicles conforming to Euro design standards					
Euro iv	Diesel oil	38.6	69.2	0.05	0.5
Euro iii	Diesel oil	38.6	69.2	0.1	0.5
Euro i	Diesel oil	38.6	69.2	0.2	0.5

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Schedule 1)

Notes: All emission factors incorporate relevant oxidation factors (sourced from the DCC's National Inventory Report).

Example: calculation of emissions from transport fuels consumed

A freight company consumes 10000 kL of automotive diesel for transport purposes. Emissions of greenhouse gases (carbon dioxide, methane and nitrous oxide) in tonnes of CO₂-e are estimated as follows: :

Emissions of carbon dioxide:

$$= (10,000 \times 38.6 \times 69.2)/1,000$$

$$= 26,711 \text{ t CO}_2\text{-e}$$

Emissions of methane:

$$= (10,000 \times 38.6 \times 0.2)/1,000$$

$$= 77 \text{ t CO}_2\text{-e}$$

Emissions of nitrous oxide:

$$= (10,000 \times 38.6 \times 0.5)/1,000$$

$$= 193 \text{ t CO}_2\text{-e}$$

$$\begin{aligned} \text{Total scope 1 GHG emissions} &= 26711 + 77 + 193 \\ &= 26,981 \text{ t CO}_2\text{-e} \end{aligned}$$

2.3 Indirect emissions from consumption of purchased electricity

This section describes the method of determining scope 2 emissions from the consumption of purchased electricity.

Indirect emission factors for the consumption of purchased electricity are provided in Table 5. State emissions factors are used because electricity flows between states are constrained by the capacity of the inter-state interconnectors and in some cases there are no interconnections. The factors estimate emissions of CO₂, CH₄ and N₂O expressed together as carbon dioxide equivalent (CO₂-e). The greenhouse gas emissions in tonnes of CO₂-e attributable to the quantity of electricity used may be calculated with the following equation.

$$Y = Q \times \frac{EF}{1\,000}$$

where:

Y is the scope 2 emissions measured in CO₂-e tonnes.

Q is the quantity of electricity purchased (kilowatt hours).

For a company operating an electricity transmission network or distribution network, **Q** is the quantity of electricity losses for that transmission network or distribution network during the year.

For **Q**, if the electricity purchased is measured in gigajoules, the quantity of kilowatt hours must be calculated by dividing the amount of gigajoules by 0.0036.

EF is the scope 2 emission factor, for the State, Territory or electricity grid in which the consumption occurs (kg CO₂-e per kilowatt hour). If the electricity is not sourced from the main electricity grid the emission factor can be either provided by the supplier of the electricity or, if that factor is not available, the emission factor for the Northern Territory may be used.

Table 5: Indirect (scope 2) emission factors for consumption of purchased electricity from the grid

State, Territory or grid description	Emission factor kg CO ₂ -e/kWh
New South Wales and Australian Capital Territory	0.89
Victoria	1.22
Queensland	0.89
South Australia	0.77
South West Interconnected System in Western Australia	0.84
Tasmania	0.23
Northern Territory	0.68

Sources: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Schedule 1) and *National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2009 (No. 1)*.

Example: calculation of emissions from electricity consumption

A company in New South Wales consumes 100,000 kWh of purchased electricity from the grid.

Emissions of greenhouse gases (scope 2) in tonnes of CO₂-e are estimated as follows:

$$= 100,000 \times (0.89 / 1000)$$

$$= 89 \text{ tonnes.}$$

Total scope 2 GHG emissions = 89 tonnes CO₂-e

2.4 Fugitive emissions from fuels

2.4.1 Coal Mining

2.4.1.1 Underground mines

Fugitive emissions from underground mines involve the release of methane and carbon dioxide during the mining process due to the fracturing of coal seams, overburden and underburden strata. Emissions also arise from post mining activities such as transportation and stockpiling of coal from the release of residual gases not released during the mining process. Emissions will also occur when coal mine waste gas is flared.

Fugitive emissions from extraction of coal

$$E_j = Q \times EF_j$$

where:

E_j is the fugitive emissions of methane (j) that result from the extraction of coal (CO₂-e tonnes).

Q is the quantity of run-of-mine coal extracted (tonnes).

EF_j is the emission factor for methane (j) (CO₂-e tonnes per tonne of run-of-mine coal extracted), as shown in Table 6.

Table 6: Emission factors for the extraction of coal (fugitive)- Underground

Activities related to extraction of coal (fugitive)	Emission factor (tonnes CO ₂ -e/ tonne run-of-mine coal)
	CH₄
Gassy underground mines	0.305
Non-gassy underground mines	0.008

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 3.5)

Direct measurement of emissions

Estimating emissions associated with underground mining operations usually involves directly measuring emissions within ventilation shafts and degasification systems. This Method is dealt with in detail in 3.6 of Chapter 3 in the *National Greenhouse and Energy Reporting (Measurement) Determination 2008*. If coal mine waste gas is captured for combustion during the year, then direct measurement of underground mining emissions should be utilised. This ensures consistent estimation methods are used for the estimation of both methane generation from the mine and from methane capture.

Fugitive emissions from post-mining activities (gassy underground mines only)

Emissions from post-mining activities (associated with gassy underground mines only) can be estimated using the method described below

$$E_j = Q \times EF_j$$

Q is the quantity of run-of-mine coal extracted (tonnes).

EF_j is taken to be 0.014, which is the emission factor for methane (j), measured in CO₂-e tonnes per tonne of run-of-mine coal extracted from the mine.

Table 7: Post-mining activities—emission factors

Post-mining activities	Emission factor (tonnes CO ₂ -e/ tonne raw coal)
	CH₄
Post mining activities associated with gassy underground mines	0.014

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 3.17)

2.4.1.2 Open cut mines

The method for estimating emissions from open cut mining operations is described below.

$$E_j = Q \times EF_j$$

where:

E_j is the fugitive emissions of methane (j) that result from the extraction of coal from the mine during the year measured in CO₂-e tonnes.

Q is the quantity of run-of-mine coal extracted from the mine during the year measured in tonnes.

EF_j is the emission factor for methane (j), measured in CO₂-e tonnes per tonne of run-of-mine coal extracted from the mine, taken to be the following:

Table 8: Emission factors for the production of coal (fugitive)- Open cut

Activities related to extraction of coal (fugitive)	Emission factor (tonnes CO ₂ -e/ tonne raw coal)
	CH₄
Open cut mines—NSW	0.045
Open cut mines—Queensland	0.017
Open cut mines—Tasmania	0.014
Open cut mines—Victoria	0.0007
Open cut mines—South Australia	0.0007
Open cut mines—Western Australia	0.017

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 3.20)

Example: calculation of emissions from open cut mining

An open cut coal mine in NSW extracts 2,554,000 tonnes of run-of-mine coal during the year. Emissions of greenhouse gas (methane) in tonnes of CO₂-e are estimated as follows:

$$E_j = Q \times EF_j$$

where:

E_j is the emissions of methane in CO₂-e tonnes.

Q is the quantity of run-of-mine coal extracted = 2,554,000 tonnes of raw coal.

EF_j is the emission factor for methane in CO₂ e tonnes per tonne of raw coal extracted from the mine. In this case, for an open cut mine in NSW the emission factor is 0.045 tonnes CO₂-e per tonne of raw coal extracted.

Therefore, the estimate of methane emissions in CO₂-e tonnes:

$$= (2,554,000 \times 0.045)$$

Total scope 1 GHG emissions = 114,930 t CO₂-e

2.4.1.3 Fugitive emissions from coal mine waste flared

Greenhouse gas emissions from flaring coal mine waste gas can be estimated by multiplying the quantity of gas flared by the energy content and emission factor for each gas type.

$$E_{(f)ij} = \frac{Q_{i,flared} \times EC_i \times EF_{ij}}{1000} \times OF_{if}$$

where:

$E_{(f)ij}$ is the emissions of gas type (j) released from coal mine waste gas (i) flared from the mine (CO₂-e tonnes).

$Q_{i,flared}$ is the quantity of coal mine waste gas (i) (cubic metres).

EC_i is the energy content factor of coal mine waste gas (i), in Table 2 (gigajoules per cubic metre).

EF_{ij} is the emission factor for gas type (j) and coal mine waste gas (i) in Table 2 (kilograms CO₂-e per gigajoule).

OF_{if} is 0.98/0.995, which is the correction factor for the oxidation of coal mine waste gas (i) flared.

2.4.1.4 Decommissioned underground mines

Fugitive emissions can be estimated from decommissioned underground mines that have been closed for a continuous period of at least 1 year but less than 20 years. A detailed description of the methodology is found in Division 3.2.4 of Chapter 3 in the *National Greenhouse and Energy Reporting (Measurement) Determination 2008*.

2.4.2 Oil and natural gas fugitive emissions

This section includes fugitive emissions from exploration, production, transport, storage, processing and refining of oil and natural gas. Other sources of emissions arising from the production processes, such as from the combustion of fuels for energy, are not described in this chapter and must be estimated using the Methods described in other chapters.

2.4.2.1 Oil and gas exploration

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the fugitive emissions of gas type (j) from a fuel type (i) flared in oil and gas exploration (CO₂-e tonnes).

Q_i is the quantity of fuel type (i) flared (tonnes).

EF_{ij} is the emission factor for gas type (j) of fuel type (i) flared (tonnes of CO₂-e per tonne flared) .

Table 9: Oil and gas exploration emission factors

Fuel type (i)	Emission factor (EF _{ij}) (tonnes CO ₂ -e/tonnes flared)		
	CO ₂	CH ₄	N ₂ O
Gas flared	2.8	0.7	0.03
Liquid flared	3.2	0.007	0.07

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 3.44)

2.4.2.2 Crude oil production

Crude oil production consists of emissions from non-flared sources (eg, gas leakage, accidental releases and storage losses) and from flaring. Separate methods for estimating emissions from non-flared and flared sources are detailed below

Crude oil production (non-flared emissions)

$$E_{ij} = \sum_k (Q_{ik} \times EF_{ijk}) + Q_i \times EF_{(l)ij}$$

where:

E_{ij} is the fugitive emissions of methane (j) (CO₂-e tonnes).

\sum_k is the total emissions of methane (j), by summing up the emissions released from each equipment type (k) specified in Table 10 (CO₂-e tonnes).

Q_{ik} is the quantities of crude oil that pass through each equipment type (k) (tonnes).

EF_{ijk} is the emission factor for methane (j) (CO₂-e tonnes per tonne of crude oil that passes through each equipment type (k)).

Q_i is the total quantity of crude oil production throughput (i) measured in tonnes.

$EF_{(l)ij}$ is 1.2×10^{-3} , which is the emission factor for methane (j) from general leaks in crude oil production, (CO₂-e tonnes per tonne of crude oil throughput).

Table 10: Oil production (other than venting and flaring) emission factors

Equipment type (k)	Emission factor (EF _{ij}) (tonnes CO ₂ -e/tonnes throughput)
	CH ₄
Internal floating tank	8.4×10^{-7}
Fixed roof tank	4.2×10^{-6}
Floating tank	3.2×10^{-6}

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 3.49)

Crude oil production (flared emissions)

$$E_{ij} = Q_i \times EF_{ij}$$

where:

NATIONAL GREENHOUSE ACCOUNTS (NGA) FACTORS

E_{ij} is the fugitive emissions of gas type (j) from a fuel type (i) flared in the crude oil production (CO₂-e tonnes).

Q_i is the quantity of fuel type (i) flared (tonnes).

EF_{ij} is the emission factor for gas type (j) of fuel type (i) flared (tonnes of CO₂-e per tonne flared) .

Table 11: Crude oil production (flared emissions) emission factors

Fuel type (i)	Emission factor (EF_{ij}) (tonnes CO ₂ -e/tonnes of fuel flared)		
	CO ₂	CH ₄	N ₂ O
Gas flared	2.8	0.7	0.03
Liquid flared	3.2	0.007	0.07

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 3.52)

Example: calculation of emissions from crude oil production

A crude oil production platform has a throughput of 710,400 tonnes of crude oil during the year. It has an equipment type constituting a floating tank in which 685,000 tonnes of crude oil throughput occurred during the year. 400 tonnes of crude oil were flared during the year.

Emissions are estimated as follows:

Part A: Crude oil production (non flared component)

$$E_{ij} = \sum_k (Q_{ik} \times EF_{ijk}) + Q_i \times EF_{(l) ij}$$

where:

E_{ij} is the emissions measured in CO₂-e tonnes of methane

\sum_k is the sum of emissions of methane (tonnes of CO₂-e) arising from relevant equipment types listed in Table 10

Q_{ik} is the quantity of crude oil (tonnes) passing through each equipment of type in Table 10. **In this case 685,000 tonnes of crude oil passes through floating tanks equipment**

EF_{ijk} is the methane emission factor specific to equipment types listed in Table 10 (tonnes of CO₂-e per tonne of crude oil throughput) . **In this case it is the emission factor for the floating tank 3.2×10^{-6} tonnes CO₂-e/tonnes fuel throughput.**

Q_i is the total quantity of crude oil production (tonnes). **In this case the total crude oil production is 710,400 tonnes.**

$EF_{(l) ij}$ **1.2×10^{-3}** , is the emission factor for methane from general leaks in crude oil production (CO₂ e tonnes per tonne of crude oil throughput).

Therefore, emissions of greenhouse gas (methane) in tonnes CO₂-e:

$$= (685,000 \times 3.2 \times 10^{-6}) + (710,400 \times 1.2 \times 10^{-3})$$

Total scope 1 GHG emissions from crude oil production (non flared component) = 855 t CO₂-e

Part B: Crude oil production (non flared component)

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the emissions of greenhouse gases (carbon dioxide, methane and nitrous oxide) from fuel flared (CO₂-e tonnes)

Q_i is the quantity of fuel type flared (tonnes). **In this case the quantity of crude oil flared is 400 tonnes.**

EF_{ij} is the emission factor for the fuel type flared (tonnes of CO₂-e emissions per tonne of fuel type flared) (Table 11).

Therefore, emissions of greenhouse gases (carbon dioxide, methane and nitrous oxide) in tonnes of CO₂ e are estimated as follows:

Emissions of carbon dioxide:

$$\begin{aligned} &= 400 \times 3.2 \\ &= 1,280 \text{ t CO}_2\text{-e} \end{aligned}$$

Emissions of methane:

$$\begin{aligned} &= 400 \times 0.007 \\ &= 3 \text{ t CO}_2\text{-e} \end{aligned}$$

Emissions of nitrous oxide:

$$\begin{aligned} &= 400 \times 0.07 \\ &= 28 \text{ t CO}_2\text{-e} \end{aligned}$$

Total scope 1 GHG emissions from Crude oil production (flared component)

$$\begin{aligned} &= 1280 + 3 + 28 \\ &= 1,311 \text{ t CO}_2\text{-e} \end{aligned}$$

Part C: Total Crude oil production emissions

$$\begin{aligned} &= \text{non-flared component} + \text{flared component} \\ &= 855 + 1311 \end{aligned}$$

Total scope 1 GHG emissions from Crude oil production = 2166 t CO₂-e

2.4.2.3 Crude oil transport

The crude oil transport subsector includes methane emissions associated with the marine, road and rail transport of crude oil. Emissions result largely from three types of activities: loading, transit, and ballasting

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the fugitive emissions of methane from crude oil transport (CO₂-e tonnes).

Q_i is the quantity of crude oil transported (tonnes).

EF_{ij} is the emission factor for methane (j), (tonnes CO₂-e per tonnes of crude oil transported).

Table 12: Oil transport emission factors

Operation or process source	Emission factor (EF_{ij}) (tonnes CO ₂ -e/tonne of oil transported)
	CH ₄
Crude oil transport (domestic)	7.3 x 10 ⁻⁴

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 3.59)

2.4.2.4 Crude oil refining

Crude oil refining consists of emissions from:

- non-flared sources (gas leakage and storage losses)
- process vents, system upsets and accidents (burning of catalyst coke for non-energy purposes)
- flaring.

Crude oil refining (non-flared emissions)

$$E_j = \sum_i (Q_i \times EF_{ij})$$

where:

E_j is the fugitive emissions of methane (j) from crude oil refined and stored in tanks (i) (CO₂-e tonnes).

\sum_i is the sum of emissions of methane (j) released during refining and from storage tanks.

Q_i is the quantity of crude oil (i) refined or stored in tanks (tonnes).

EF_{ij} is the emission factor for tonnes of methane (j) (tonnes CO₂-e per tonne of crude oil refined and crude oil stored in tanks).

Table 13: Oil refining and storage emission factors

Operation or process source	Emission factor (EF_{ij}) (tonnes CO ₂ -e/tonne of oil refined or stored)	
	CH ₄	
Crude oil refining	7.1 x 10 ⁻⁴	
Crude oil storage	1.3 x 10 ⁻⁴	

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 3.63)

Crude oil refining (combustion of catalyst coke for non-energy purposes)

$$E_i = Q_i \times CCF_i \times 3.664$$

where:

E_i is the fugitive emissions during the year from deliberate releases from process vents, system upsets and accidents in the crude oil refining measured in CO₂ e tonnes.

Q_i is the quantity of refinery coke (i) burnt to restore the activity of the catalyst of the crude oil refinery (and not used for energy) during the year measured in tonnes.

CCF_i is the carbon content factor for refinery coke (i). See Appendix 3.

3.664 is the conversion factor to convert an amount of carbon in tonnes to an amount of carbon dioxide in tonnes.

Crude oil refining (flared emissions)

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the fugitive emissions of gas type (j) from a fuel type (i) flared in crude oil refining (CO₂-e tonnes).

Q_i is the quantity of fuel type (i) flared (tonnes).

EF_{ij} is the emission factor for gas type (j) of fuel type (i) flared (tonnes of CO₂-e per tonne flared)

Table 14: Refinery gas flaring emission factors

Fuel type (i)	Emission factor (EF_{ij}) (tonnes CO ₂ -e/tonnes flared)		
	CO ₂	CH ₄	N ₂ O
Gas flared	2.7	0.1	0.03

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 3.67)

2.4.2.5 Natural gas production and processing (other than emissions that are vented or flared)

$$E_{ij} = \sum_k (Q_{ik} \times EF_{ijk}) + Q_i \times EF_{(l)ij}$$

where:

E_{ij} is the fugitive emissions of methane (j) (CO₂-e tonnes).

\sum_k is the total emissions of methane (j), by summing up the emissions released from each equipment type (k) specified in Table 15 (CO₂-e tonnes).

Q_{ik} is the quantities of natural gas that pass through each equipment type (k) (tonnes).

EF_{ijk} is the emission factor for methane (j) (CO₂-e tonnes per tonne of natural gas that passes through each equipment type (k)).

Q_i is the total quantity of natural gas (i) that passes through the natural gas production and processing measured in tonnes.

$EF_{(l)ij}$ is 1.2×10^{-3} , which is the emission factor for methane (j) from general leaks in the natural gas production and processing, (CO₂-e tonnes per tonne of natural gas throughput).

Table 15: Natural gas production and processing (other than emissions that are vented or flared) emission factors

Equipment type (k)	Emission factor EF_{ijk} (tonnes CO ₂ -e/tonnes throughput)
	CH ₄
Internal floating tank	8.4×10^{-7}
Fixed roof tank	4.2×10^{-6}
Floating tank	3.2×10^{-6}

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 3.72)

2.4.2.6 Natural gas transmission

Transmission mains are defined as high-pressure pipelines greater than 1050 kilopascals, as used in the Energy Supply Association of Australia natural gas statistics.

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the fugitive emissions of gas type (j) from natural gas transmission through a system of pipelines of length (i) (CO₂-e tonnes).

Q_i is the length of the system of pipelines (i) (kilometres).

EF_{ij} is the emission factor for gas type (j), (tonnes of CO₂-e emissions per kilometre of pipeline (i)).

Table 16: Natural gas transmission emission factors

Operation or process source	Emission factor (tonnes CO ₂ -e/km pipeline length)	
	CO ₂	CH ₄
Natural gas transmission	0.02	8.7

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 3.76)

Example

A company has a network of natural gas transmission pipelines with a total length of 3600 km, over a year. Emissions are estimated as follows:

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the emissions measured in CO₂-e tonnes of gas type (j), being either carbon dioxide or methane, released from natural gas transmission through a system of pipelines of length (i) (CO₂-e tonnes).

Q_i is the length of the system of pipelines (i) (kilometres). In this case pipeline length is 3600 km.

EF_{ij} is the emission factor for gas type (j) being 0.02 for carbon dioxide and 8.7 for methane (tonnes of CO₂-e emissions per kilometre of pipeline (i)). See Table 6.

Therefore, to estimate greenhouse gas emissions (carbon dioxide and methane) in CO₂-e tonnes:

Emissions of carbon dioxide:

$$= 3600 \times 0.02$$

$$= 72 \text{ t CO}_2\text{-e}$$

Emissions of methane

$$= 3600 \times 8.7$$

$$= 31,320 \text{ t CO}_2\text{-e}$$

$$\text{Total scope 1 GHG emissions} = 72 + 31,320$$

$$= 31,392 \text{ t CO}_2\text{-e}$$

2.4.2.7 Natural gas distribution

The boundary between natural gas transmission and distribution is generally taken to be the city gate regulator stations at which gas pressures are reduced from transmission pressures to sub-transmission pressures. For the purposes of this methodology, natural gas distribution comprises low, medium and high-pressure reticulation ≤ 1050 kilopascals.

Greenhouse gases emitted from utility pipeline systems are estimated from the following equation:

$$E_j = S \times \%UAG \times 0.55 \times C_j$$

where:

E_j is the greenhouse gas emitted from the gas distribution system in utility pipelines system (in tonnes CO₂-e)

S is the total gas utility sales from the pipeline system (in terajoules)

$\%UAG$ is the percentage of unaccounted for gas in a state's pipeline system, relative to the amount issued annually by gas utilities (see Table 17)

C_j is the natural gas composition factor for natural gas supplied from the state pipeline system (in tonnes CO₂-e per terajoule) (see Table 17)

0.55 represents the portion of unaccounted for gas allocated as leakage

Table 17: Natural gas combustion emission factors and unaccounted for gas factors

State	Unaccounted for gas (%UAG)	Natural gas composition factor (tonnes CO ₂ -e/TJ) (C)	
	UAG	CO ₂	CH ₄
NSW and ACT	2.40	0.8	328
VIC	2.75	0.9	326
QLD	2.63	0.8	317
SA	4.00	0.8	328
WA	2.55	1.1	306
NT	0.10	0.0	264
TAS	0.40	0.9	326

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 3.80)

2.4.2.8 Natural gas production and processing (emissions that are vented or flared)

Natural gas production and processing - venting

Venting refers to the controlled release of unburnt gases to the atmosphere. Venting at oil and gas processing facilities is mainly associated with the release of CO₂, which is extracted from the raw gas stream in the course of gas processing. Because separation of the other components of the gas stream from the CO₂ is incomplete, the vented CO₂ contains small quantities of methane. The quantities of CO₂ and methane vented will depend on the concentration of CO₂ in the raw gas, which varies significantly between gas fields, and on the mode of operation and efficiency of the CO₂ stripping plant. The volumes of the vent gas and CO₂ and methane concentrations are monitored as a part of routine plant operation, therefore no estimation formula is provided.

Natural gas production and processing – flaring

Flaring refers to the controlled release to combustion of a mixed flammable gas stream. At gas processing plants, flared gas may arise from natural gas processing. Where there is no market for gas separated from the wellhead production stream, the gas is reinjected or flared.

This subsector does not include flaring from petroleum refining activities, which should be reported separately under 1.B.2a.iv Crude Oil refining and storage.

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the emissions of gas type (j) from a fuel type (i) flared (CO₂-e tonnes)

Q_i is the quantity measured in tonnes of gas flared.

EF_{ij} is the emission factor for gas type (j) for fuel type (i) flared (tonnes of CO₂-e per tonne of gas flared).

Table 18: Flaring emission factors

Operation or process source	Emission factor (tonnes CO ₂ -e/tonnes flared)		
	CO ₂	CH ₄	N ₂ O
Gas flared	2.7	0.1	0.03

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 3.85)

3 Industrial processes including use of synthetic gases

Greenhouse gas emissions from industrial processes other than from combustion of fuels for energy may be estimated by using the methods described in this section. These emission factors are national average emissions factors and can be used in the absence of plant- or company-specific data. For information on estimating activity data, refer to the National Greenhouse and Energy Reporting (Measurement) Determination 2008.

3.1 Cement clinker production

$$E_{ij} = (EF_{ij} + EF_{toc,j}) \times (A_i + A_{ckd} \times F_{ckd})$$

where:

E_{ij} is the emissions of CO₂ released from the production of cement clinker (CO₂-e tonnes)

EF_{ij} is the emission factor for cement clinker (tonnes of CO₂ emissions per tonne of clinker produced). See Table 19.

A_i is the quantity of cement clinker produced (tonnes)

A_{ckd} is the quantity of cement kiln dust (CKD) produced (tonnes)

$EF_{toc,j}$ is the emission factor for carbon-bearing non-fuel raw material (tonnes of CO₂ emissions per tonne of clinker produced). See Table 19.

F_{ckd} is the degree of calcination of cement kiln dust (range from 0% to 100%). If the information is not available the degree is assumed to be 100%, that $F_{ckd}=1$

Table 19: Clinker production emission factors

Source	Emission factor (tonnes CO ₂ -e per tonne)
	CO ₂
EF_{ij}	0.534
$EF_{toc,j}$	0.010

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 4.4)

Example: Calculation of emissions generated from cement clinker production

A company produces 20,000 tonnes of cement clinker and 300 tonnes of cement kiln dust per year. The degree of calcination of the cement dust is not known. The GHG emissions are calculated as follows:

$$= (0.534 + 0.01) \times (20,000 + 300 \times 1)$$

$$= 11,043 \text{ tonnes CO}_2\text{-e}$$

Total scope 1 GHG emissions = 11,043 tonnes CO₂-e

3.2 Lime production

This section applies to lime production other than in-house lime production in the ferrous metals industry, which should apply the method described under “Other uses of carbonates”.

$$E_{ij} = A_i \times EF_{ij}$$

where:

E_{ij} is the emissions of CO₂ from the production of lime (CO₂-e tonnes)

A_i is the amount of lime produced (tonnes)

EF_{ij} is the CO₂ emission factor (tonnes of CO₂ / tonnes lime produced). See Table 20.

Table 20: Lime production emission factors

Source	Emission factor (EF_{ij}) (tonne CO ₂ -e per tonne)
	CO ₂
Commercial lime production	0.675
In-house lime production	0.730

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 4.13)

3.3 Use of carbonates for the production of a product other than cement clinker, lime or soda ash

This section applies to calcination or any other use of carbonates that generates CO₂ (excluding cement clinker, lime production or soda ash production) including the in-house lime production in the ferrous metals industry. Examples of industrial processes involving the consumption of carbonates include:

- Metallurgy
- Glass manufacturing including fibreglass and mineral wools
- Magnesia production

$$E_{ij} = Q_i \times EF_{ij} \times F_{cal}$$

where:

E_{ij} is the annual emissions of CO₂ from the consumption of carbonate (CO₂-e tonnes)

Q_j is the quantity of raw carbonate material consumed (tonnes)

EF_{ij} is the CO₂ emission factor for each carbonate material type (tonnes CO₂ per tonne of carbonate). See Table 21.

F_{cal} is the fraction of the carbonate calcined. If the information is not available the degree is assumed to be 100%, that $F_{cal} = 1$

Total greenhouse emissions are calculated by summing the emissions of each carbonate type consumed.

Table 21: Calcination of carbonates emission factors

Source of carbonate consumption	Emission factor (EF_{ij}) (tonne CO ₂ -e per tonne)
	CO ₂
Limestone (calcium carbonate)	0.396
Magnesium carbonate	0.522
Dolomite	0.453

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 4.22)

3.4 Soda ash use

This section applies to the use and production of soda ash. Examples of soda ash in industrial processes include:

- Glass production
- Soap and detergent production
- flue gas desulphurisation
- pulp and paper production

$$E_{ij} = Q_i \times EF_{ij}$$

where:

E_{ij} is the emissions of CO₂ from the use of soda ash (CO₂-e tonnes)

Q_i is the amount of soda ash consumed (tonnes)

EF_{ij} is the CO₂ emission factor (tonnes of CO₂ / tonnes of soda ash used). See Table 22.

Table 22: Soda ash consumption emission factor

Source	Emission factor (EF_{ij}) (tonne CO ₂ -e per tonne)
	CO ₂
Soda ash use	0.415

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 4.29)

3.5 Ammonia production

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ij}}{1000} - R$$

where:

E_{ij} is emissions of CO₂ (tonnes of CO₂-e)

Q_i is the quantity of each fuel consumed as a feedstock (cubic metres)

EC_i is the energy content of the fuel type (i) used as a feedstock (gigajoules per cubic metre)

If Q_i is measured in gigajoules, then EC_i is 1.

EF_{ij} is the emission factor for each fuel type (i) used as a feedstock (kilograms CO₂-e per gigajoule)

R is the CO₂ recovered for downstream use (tonnes of CO₂-e)

Energy content and gas emission factors for each fuel type should be taken from the fuel combustion emission factors listed in Tables 1, 2 and 3.

3.6 Nitric acid production

$$E_{ijk} = EF_{ijk} \times A_{ik}$$

where:

E_{ijk} is the emissions of nitrous oxide from the production of nitric acid at the plant type k (tonnes)

A_{ik} is the quantity of nitric acid produced from plant type k (tonnes)

EF_{ijk} is the emission factor of nitrous oxide from plant type k (tonnes). See Table 23.

Table 23: Nitric acid production emission factors

Plant type (k)	Emission factor (tonnes CO ₂ -e per tonne of production)
	N ₂ O
Atmospheric pressure plants (low pressure)	1.55
Medium pressure combustion plant	2.17
High pressure plant	2.79

Source: IPCC 2006. National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 4.47).

3.7 Adipic acid production

Methods for estimating emissions from the production of adipic acid are given in section 3.4 of the 2006 IPCC Guidelines.

3.8 Carbide production

Methods for estimating emissions from the carbide production are given in section 3.6 of the 2006 IPCC Guidelines.

3.9 Chemical or mineral production, other than carbide production, using a carbon reductant

This section covers emissions from the production of any chemical or mineral product, other than carbide where a carbon reductant is used (for example, the production of titanium dioxide or synthetic rutile)

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ij}}{1000}$$

where:

E_{ij} is emissions of CO₂ from the use of a carbon reductant in the production of a mineral or chemical product other than carbide

Q_i is the quantity of each fuel type i consumed as a reductant(tonnes)

EC_i is the energy content factor of the fuel type i used as a reductant (gigajoules per tonne)

EF_{ij} is the emission factor for the fuel type i used as a reductant (including effects of oxidation) (kilograms per gigajoule)

Default energy content and emission factors for each fuel type should be taken from Tables 1, 2 and 3.

3.10 Iron and steel or other metal production using an integrated metalworks

Carbon dioxide emissions from integrated metalworks are estimated using a mass balance approach. Total quantities of carbon inputs, outputs and consumption are considered in steps 1 to 5 detailed below.

The emissions are worked out as a total of emissions released from the integrated metalworks and from all other emissions released from the operation of the activity (including the production of coke).

Primary sources of emissions from integrated metalworks include combustion of fuels for making coke and from the use of fuel as a carbon reductant in iron and steel production. Other sources include emissions from use of carbonates.

STEP 1

Calculate the carbon content in fuel types (i) or carbonaceous input material delivered for the activity during the year measured in tonnes of carbon as follows:

$$\sum_i CCF_i \times Q_i$$

where:

\sum_i means sum the carbon content values obtained for all fuel types (i) or carbonaceous input material.

CCF_i is the carbon content factor in Appendix 3, measured in tonnes of carbon for each appropriate unit of fuel type (i) or carbonaceous input material consumed during the year from the operation of the activity.

Q_i is the quantity of fuel type (i) or carbonaceous input material delivered for the activity during the year measured in an appropriate unit.

STEP 2

Calculate the carbon content in products (p) leaving the activity during the year measured in tonnes of carbon as follows:

$$\sum_p CCF_p \times A_p$$

where:

\sum_p means sum the carbon content values obtained for all product types (p).

CCF_p is the carbon content factor measured in tonnes of carbon for each tonne of product type (p) produced during the year.

A_p is the quantity of product types (p) produced leaving the activity during the year measured in tonnes.

STEP 3

Calculate the carbon content in waste by-product types (*r*) leaving the activity, other than as an emission of greenhouse gas, during the year, measured in tonnes of carbon, as follows:

$$\sum_r CCF_r \times Y_r$$

where:

\sum_r means sum the carbon content values obtained for all waste by-product types (*r*).

CCF_r is the carbon content factor measured in tonnes of carbon for each tonne of waste by-product types (*r*).

Y_r is the quantity of waste by-product types (*r*) leaving the activity during the year measured in tonnes.

STEP 4

Calculate the carbon content in the amount of the increase in stocks of inputs, products and waste by-products held within the boundary of the activity during the year in tonnes of carbon as follows:

$$\sum_i CCF_i \times \Delta S_{qi} + \sum_p CCF_p \times \Delta S_{ap} + \sum_r CCF_r \times \Delta S_{yr}$$

where:

\sum_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

ΔS_{qi} is the increase in stocks of fuel type (*i*) for the activity and held within the boundary of the activity during the year measured in tonnes.

\sum_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

ΔS_{ap} is the increase in stocks of product types (*p*) produced by the activity and held within the boundary of the activity during the year measured in tonnes.

\sum_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the increase in stocks of waste by-product types (*r*) produced from the operation of the activity and held within the boundary of the activity during the year measured in tonnes.

STEP 5

Calculate the emissions of carbon dioxide released from the operation of the activity during the year measured in CO₂-e tonnes as follows:

- (a) add the amounts worked out under steps 2, 3 and 4 to work out a new amount (**amount A**);
- (b) subtract amount A from the amount worked out under step 1 to work out a new amount (**amount B**);
- (c) multiply amount B by 3.664 to work out the amount of emissions released from the operation of the activity during a year.

3.11 Ferroalloy metals

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ij}}{1\ 000}$$

where:

E_{ij} is emissions of CO₂ from the consumption of a carbon reductant in the production of ferroalloy metal (tonnes)

Q_i is the quantity of each carbon reductant used in the production of the metal (tonnes)

EC_i is the energy content for fuel type (i) consumed as a carbon reductant (gigajoule per tonne)

EF_{ij} is the emission factor of each carbon reductant used (kilograms of CO₂-e per gigajoule)

Default energy content and emission factors for each fuel type should be taken from Tables 1, 2 and 3.

3.12 Aluminium — emissions from consumption of baked carbon anodes in aluminium production

$$E_{ij} = A_i \times EF_{ij}$$

where:

E_{ij} is the emission of CO₂ from aluminium smelting (tonnes)

A_i is the amount of aluminium produced (tonnes)

EF_{ij} is the CO₂ emission factor for carbon anode consumption (tonnes of CO₂-e emissions per tonne of aluminium produced), estimated according to:

$$EF_{ij} = NAC \times \left(\frac{100 - S_a - Ash_a}{100} \right) \times 3.664$$

where:

0.413 is the tonnes of baked carbon anode consumed per tonne of aluminium produced

S_a is the sulphur content in baked anodes (by % weight; the default is assumed to be equal to 2%)

Ash_a is the ash content in baked anodes (by % weight, the default is assumed to be equal to 0.4%)

3.13 Aluminium — emissions from production of baked carbon anodes in aluminium production

$$E_{ij} = (GA - Hw - BA - WT) \times 3.664 + \left(\frac{\sum Q_i}{BA} \times BA \times \frac{(100 - S_i - Ash_i)}{100} \right) \times 3.664$$

where:

E_{ij} is the emissions of CO₂ from baked carbon anode production

GA is the initial weight of green anodes used in the production process of the baked carbon anode

BA is baked anode production (tonnes)

Hw is the weight of the hydrogen content in green anodes (tonnes) (the default value for Hw is 0.5% of GA)

WT is waste tar collected (tonnes)

$\sum Q_i$ is the quantity of fuel consumed in the production of baked carbon anodes (tonnes)

S_i is the sulphur content in packing coke (by % weight, assumed to be 2%)

Ash_i is the ash content in packing coke (by % weight, assumed to be 0.4%)

3.14 Aluminium (perfluorinated carbon compound emissions) – tetrafluoromethane and hexafluoroethane

$$E_{ij} = A_i \times EF_{ij}$$

where:

E_{ij} is the process emission of tetrafluoromethane (CF₄) and hexafluoroethane (C₂F₆) from primary aluminium production (CO₂-e tonnes)

A_i is the amount of primary aluminium production (tonnes)

EF_{ij} is the emission factor for CF₄ or C₂F₆, (tonne CO₂-e per tonne aluminium).

Table 24: Aluminium perfluorinated carbon compound emission factors

Source	Emission factor (EF _{pf}) tonne CO ₂ -e per tonne	
	Tetrafluoromethane	Hexafluoroethane
	CF ₄	C ₂ F ₆
Aluminium production	0.26	0.05

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Division 4.4.4).

3.15 Other metals

$$E_{ij} = \frac{Q_i \times EC_i \times EF_i}{1\ 000}$$

where:

E_{ij} is emissions of CO₂ from the production of the metal (tonnes)

Q_i is the quantity of each fuel type (i) used as carbon reductant in the production of the metal (expressed in tonnes)

EC_i is the energy content of the fuel type (i) used as reductant (gigajoules per tonne)

EF_i is the emission factor of the fuel type (i) used as reductant (kilograms of CO₂ per gigajoule)

Default energy content and emission factors for each fuel type should be taken from Tables 1, 2 and 3.

3.16 Industrial processes — emissions of hydrofluorocarbons and sulphur hexafluoride gases

$$E_{jk} = Stock_{jk} \times L_{jk}$$

where

E_{jk} is the emissions of HFC or SF₆, summed over each equipment type (tonnes of CO₂-equivalent);

$Stock_{jk}$ is the stock of HFC or SF₆ contained in equipment, by equipment type (tonnes of CO₂-e); and

L_{jk} is the default leakage rates by equipment type.

NATIONAL GREENHOUSE ACCOUNTS (NGA) FACTORS

For the factor **Stock_k**, an estimation of the stock of synthetic gases contained in an equipment type may be based on the following sources:

- (a) the stated capacity of the equipment according to the manufacturer's nameplate;
- (b) estimates based on:
 - (i) the opening stock of gas in the equipment; and
 - (ii) transfers into the facility from additions of gas from purchases of new equipment and replenishments; and
 - (iii) transfers out of the facility from disposal of equipment or gas.

Table 25: Leakage rates for synthetic gases

Equipment type	Default annual leakage rates of gas	
	HFCs	SF ₆
Commercial air conditioning—chillers	0.09	
Commercial refrigeration - supermarket systems	0.23	
Industrial refrigeration including food processing and cold storage	0.16	
Gas insulated switchgear and circuit breaker applications		0.005

Source: National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Section 4.102).

Example: Calculation of emissions generated from the operation of a commercial chiller

A company operates a commercial air conditioning-chiller, which contains 160 kg charge of HFC134a.

Convert HFC134a into a CO₂-equivalent using the global warming potential of 1300 (from Appendix 1)

$$= 160 \times 1300/1000$$

$$= 208 \text{ tonnes CO}_2\text{-e}$$

Applying the annual leakage rate of 0.09 (i.e. 9%) gives:

$$= 0.09 \times 208$$

Total scope 1 GHG emissions = 19 tonnes CO₂-e

4 Waste emissions

Throughout this Waste chapter, emissions of CO₂ generated from waste management are considered to be from biomass sources and therefore do not need to be estimated. For example, landfill gas comprises both methane and carbon dioxide but only the methane component should be considered.

Carbon dioxide produced from the flaring of methane from landfill gas or other emission sources is also considered as having been derived from biomass sources.

Emissions of all gases arising from other non-waste processes from a facility, such as emissions from the combustion of fuels for energy, should be estimated using methods described in the appropriate chapter.

4.1 Methane released from landfills - (other than from flaring of methane)

For companies that operate landfill sites and wish to calculate scope 1 emissions, please refer to Chapter 5 – Part 5.2 of the National Greenhouse and Energy Reporting (Measurement) Technical Guidelines June 2009 for guidance. For companies wishing to calculate scope 3 emissions from the disposal of their waste outside the organisation boundaries (eg, waste taken to municipal landfill), please refer to Appendix 4 of this workbook.

4.2 Biological treatment of solid waste at the landfill – composting and anaerobic digestion

Greenhouse emissions from biological treatment of solid waste may be estimated according to:

$$CH_4 \text{ Emissions} = \sum_i (Q_i \times EF_i) - R$$

where:

CH_4 Emissions = total CH₄ emissions in inventory year, tonnes

Q_i = mass of wet organic waste treated by biological treatment type i, tonnes

EF = emission factor for treatment i, tonnes CO₂-e/tonne of wet waste treated and equal to:

- for composting: 0.08
- for anaerobic digestion: 0.02

R = total amount of CH₄ recovered in inventory year, tonnes CO₂-e

Nitrous oxide emissions from biological treatment

$$N_2O \text{ Emissions} = \sum_i (Q_i \times EF_i)$$

where:

N_2O Emissions = total N_2O emissions in inventory year, tonnes of CO_2 -e

Q_i = mass of wet organic waste treated by biological treatment type i , tonnes

EF = emission factor for treatment i , tonnes of CO_2 -e/tonnes of wet waste treated and equal to:

- for composting: 0.09
- for anaerobic digestion: 0.0

4.3 Wastewater handling (domestic and commercial)

Companies that own and operate wastewater treatment facilities and wish to calculate a scope 1 emissions estimate for this source, please refer to Chapter 5 – Part 5.3 of the National Greenhouse and Energy Reporting (Measurement) Technical Guidelines June 2009 for guidance. For companies wishing to calculate scope 3 emissions from the disposal of their waste outside the organisation boundaries (eg, waste disposed to municipal treatment works), please refer to Appendix 4 of this workbook.

4.4 Wastewater handling (Industrial) - wastewater treatment

For companies that treat industrial wastewater onsite and capture less than 75% of the estimated methane generated, the following equations can be used to calculate an emissions estimate from this source:

$$CH_{4gen} = \{[(\sum COD_{wi} - COD_{sl}) \times (F_{wan} \times EF_{wij})] + [(COD_{sl} - COD_{trl} - COD_{tro}) \times F_{slan} \times EF_{slij}]\} - \gamma(Q_{total})$$

where:

CH_{4gen} is the annual methane emissions from the on-site treatment of industrial wastewater in tonnes

$\sum_{w,i}$ is the total $COD_{w,i}$ of wastewater entering the plant.

$COD_{w,i}$ is the COD in wastewater entering the plant related to the production by the plant of the commodities listed in Table 26 during the year measured in tonnes of COD. Where facility-specific data are available on COD quantities, these should be used. Where these data are not available the following equation together with the default values in table 26 can be used:

$$COD_{w,i} = Prod_i \times W_{gen,i} \times \frac{COD_{con,i}}{1\,000}$$

where:

$Prod_i$ is the total production by the plant of each commodity during the year measured in tonnes.

$W_{gen,i}$ is the wastewater generation rate from the production of each commodity produced during the year and measured in cubic metres or kilolitres per tonne of commodity.

$COD_{con,i}$ is the COD concentration in kilograms of COD per cubic metre of wastewater entering the plant during the year from the production of each commodity (defaults by commodity type are listed in table 26 below).

COD_{sl} is the quantity of COD removed as sludge from wastewater during the year measured in tonnes of COD, worked out as follows:

$$COD_{sl} = COD_{w,i} \times F_{sl}$$

where:

$COD_{w,i}$ is the COD in wastewater entering the plant used in the production of each commodity during the year measured in tonnes of COD.

F_{sl} is the fraction of COD removed from wastewater as sludge by the plant during the year (in the absence of a plant-specific factor, the default value is 0.15).

F_{wan} is the fraction of COD in wastewater anaerobically treated by the plant during the year (defaults by commodity type are listed in table 26 below).

$EF_{w,ij}$ is the methane emission factor for industrial wastewater (default is 5.3).

COD_{trl} is the quantity of COD in sludge transferred out of the plant and removed to landfill during the year measured in tonnes of COD.

COD_{tro} is the quantity of COD in sludge transferred out of the plant and removed to a site other than landfill during the year measured in tonnes of COD.

F_{slan} is the fraction of COD in sludge anaerobically treated by the plant during the year.

$EF_{sl,ij}$ is the methane emission factor for the treatment of sludge by the plant (default is 5.3).

Q_{total} is the quantity of methane captured for combustion, flaring or transfer off-site measured in cubic metres.

γ is the factor $6.784 \times 10^{-4} \times 21$ converting cubic metres of methane at standard conditions to tonnes

Table 26: Default industrial wastewater treatment parameters by commodity type

Commodity	$W_{gen,i}$ default value	$COD_{con,i}$ default value	F_{wan} default value
Dairy Product (ANZSIC code 113)	5.7	0.9	0.4
Pulp,Paper and Paperboard (ANZSIC code 1510)	26.7	0.4	0.0
Meat and Poultry (ANZSIC codes 1111 and 1112)	13.7	6.1	0.4

NATIONAL GREENHOUSE ACCOUNTS (NGA) FACTORS

Commodity	$W_{gen,i}$ default value	$COD_{con,i}$ default value	F_{wan} default value
Organic chemicals (ANZSIC codes 18 and 19)	67.0	3.0	0.1
Raw Sugar (ANZSIC code 1181)	0.4	3.8	0.3
Beer (ANZSIC code 1212)	5.3	6.0	0.5
Wine and Other Alcoholic Beverage (ANZSIC code 1214)	23.0	1.5	0.0
Fruit and Vegetables (ANZSIC code 1140)	20.0	0.2	1.0

For full details of all methodologies available to companies treating their industrial wastewater on-site, please refer to Part 5.4 of the National Greenhouse and Energy Reporting System Measurement Technical Guidelines June 2009.

4.5 Wastewater handling (industrial) — Flaring of methane in sludge biogas

Greenhouse emissions from the flaring of methane in sludge biogas may be estimated according to:

$$E_{j \text{ flared}} = Q_{\text{flared}} \times EC_i \times \frac{EF_{ij}}{1\,000}$$

where:

$E_{j \text{ flared}}$ is the emissions of gas type (j) released from flaring of the methane in sludge biogas by the plant during the year measured in CO₂-e tonnes.

Q_{flared} is the quantity of methane in sludge biogas flared by the plant during the year measured in cubic metres.

EC_i is the energy content of methane in sludge biogas measured in gigajoules per cubic metre.

EF_{ij} is the relevant emission factor for gas type (j) for methane in sludge biogas in CO₂-e tonnes per gigajoule.

For Q_{flared} , the methane in sludge biogas is taken to constitute 70% of the sludge biogas.

4.6 Waste incineration - carbon dioxide emissions

Emissions from the incineration of waste may be estimated according to:

$$E_i = Q_i \times CC_i \times FCC_i \times OF_i \times 3.664$$

where:

E_i is the emissions of carbon dioxide released from the incineration of waste type (i) by the plant during the year measured in CO₂-e tonnes.

Q_i is the quantity of waste type (i) incinerated by the plant during the year measured in tonnes of wet weight value in accordance with Division 2.3.6.

CC_i is the carbon content of waste type (i) (default is 0.60 for clinical waste).

FCC_i is the proportion of carbon in waste type (i) that is of fossil origin (default 0.4).

OF_i is the oxidation factor for waste type (i) (default 1).

5 Agriculture

5.1 Introduction

This section covers the estimation of emissions from grazing, cropping, and horticulture; and from agricultural burning.

Emissions from other on-farm activities are accounted for in other sections:

- Vehicle fuel use is covered in Section 2.2 *Transport fuels*;
- The burning of fuels in plant and equipment is covered in Section 2.1 Stationary energy emissions.
- Land conversion and tree planting are addressed in Section 5 *Land-use change and forestry (vegetation sinks)*. Section 5 gives advice on estimating (1) emissions of carbon dioxide (CO₂) from the conversion of forest to pasture or cropland but not from other agricultural sources whose emissions are assumed to be removed again in the following growing season, and (2) removals of CO₂ by forest plantations and large-scale tree planting.

5.2 Greenhouse gas emissions from agriculture

Emissions of greenhouse gases are produced on agricultural lands as a result of a number of natural and human-induced processes. These include the decay or burning of biomass, feed digestion by ruminant livestock, the addition of nitrogen fertiliser and animal manure, crop residues returned to the soil, nitrogen fixation, nitrogen leaching and runoff, atmospheric deposition, and the anaerobic decomposition of organic matter during flood irrigation.

The principal greenhouse gases estimated for agriculture are methane (CH₄) and nitrous oxide (N₂O). Emissions and removals of CO₂ from agriculture (i.e., biological on-farm sources) are covered in Section 6.

The main agricultural sources of CH₄ are the digestion of feed by livestock, manure management and 'savannah burning' (i.e., the burning of pastoral grassland and woodland). The main agricultural source of N₂O is soils, primarily as a result of the use of nitrogen-based fertilisers on crops and pastures. Manure management and savannah burning are also sources of N₂O. Crop residue burning produces some CH₄ and N₂O.

Greenhouse gas emissions represent a loss of valuable resources from farming systems. There is a wide range of actions that land managers can take in order to enhance the efficiency with which these resources are used, thereby reducing their greenhouse impacts and improving productivity at the same time. Further information on greenhouse gas emissions from agriculture can be found at: www.climatechange.gov.au/agriculture

For further information on greenhouse and agriculture issues, including options for cost-effective emissions reductions, visit: www.climatechange.gov.au/agriculture

For information on emissions reporting in the agriculture sector contact:

Department of Climate Change

GPO Box 854

Canberra ACT 2601

Email: agriculture@climatechange.gov.au

5.3 Estimating agricultural emissions

State and national-level estimates of greenhouse gas emissions from agriculture are prepared using the methodology set out in the *National Inventory Report 2007*.

Organisations wishing to report emissions from their agricultural operations may draw on this national methodology to make indicative estimates, but should note that the methodology uses regional averages not directly applicable to specific operations dependent on local conditions.

6 Land-use change and forestry (vegetation sinks)

6.1 Introduction

Actively growing forests take up (sequester) carbon from the atmosphere. The amount of carbon stored in an undisturbed forest can increase over time, until trees are mature and growth is balanced by decay. Natural events, e.g. fire and pest attack, and management actions such as harvesting reduce forest carbon stocks. Forest planting can also result in greenhouse gas emissions, e.g. from soil disturbance. Where sequestration exceeds emissions, a forest is a sink. If tree planting has been undertaken or is planned to help reduce greenhouse gas emissions, the amount of carbon sequestered can be estimated.

Deforestation produces greenhouse gas emissions from the burning and decay of cleared vegetation and changes in soil carbon.

6.2 National accounting approach

The accounting approach for land use change and forestry activities under Australian Government programs reflects the approach taken to these activities in preparing Australia's national greenhouse gas inventory. This aims to ensure that project-level reporting under Australian Government programs is consistent with Australia's national inventory reporting.

6.3 Activities covered under Australia's national inventory

Australia reports greenhouse gas emissions and carbon sequestration from land use change and forestry according to the accounting rules that apply to its 108% Kyoto Protocol emissions target, and to meet obligations under the United Nations Framework Convention on Climate Change (UNFCCC).

Forestry activities (afforestation and reforestation) included under these Kyoto provisions are those that establish a forest of trees:

- with a potential height of at least two metres and crown cover of at least 20 per cent; and
- in patches greater than 0.2 hectare in area, and
- since 1 January 1990, on land that was clear of forest at 31 December 1989; and
- by direct human induced methods, such as planting, direct seeding, or the promotion of natural seed sources; and
- within Australia.

Under the UNFCCC, accounting requirements cover a broader range of forestry activities, including the growth, harvesting and regrowth of all managed native forests and plantations (including plantations that meet the above criteria as well as plantations established prior to 1 January 1990 or on land cleared after 31 December 1989).

Land use change, or deforestation, refers to the deliberate, human-induced removal of forest cover (trees with a potential height of at least two metres and crown cover of at least 20 per cent in patches greater than 0.2 hectare in area) and replacement with a non-forest land use.

6.4 Accounting method

The national greenhouse gas account for land-based activities is estimated by the National Carbon Accounting System (NCAS). The NCAS is a model-based accounting system supported by resource inventories, field studies and remote sensing methods.

The National Carbon Accounting Toolbox (the Toolbox) allows access to NCAS modelling and data, providing a set of tools for tracking carbon stock changes in forests, including carbon sequestration and losses, e.g. through harvesting. Use of the Toolbox ensures that project-level carbon accounts for forest sinks are determined on a similar basis to Australia's national reporting.

Carbon accounting for forest sinks is based on the stock change approach. The change in carbon stocks over a period of time is calculated using the formula:

$$\Delta C_i = C_i - C_{i-1}$$

where: ΔC_i = change in carbon stocks in year i

C_i = carbon stocks in year i

C_{i-1} = carbon stocks in the year before year i

This approach provides for estimating the annual amount of carbon added to, or lost from, a forest's carbon stocks.

6.5 Accounting method for Greenhouse program participants

Participants in Australian Government greenhouse programs should use the National Carbon Accounting Toolbox to estimate greenhouse gas accounts for land use change and forestry activities.

Carbon sequestration is generally reported in either tonnes of carbon or tonnes of carbon dioxide. It is important to note which is being used. The carbon in trees is not in the form of carbon dioxide and is often reported as elemental carbon. To express a quantity of carbon as an amount of carbon dioxide, the carbon value can be multiplied by 3.67 (this is a simple conversion that does not take into account other gases).

The Toolbox covers cycling of carbon in forests and forest soils. Capability to account for non-carbon dioxide greenhouse gases is currently being developed through the NCAS, and will be incorporated in a future version of the Toolbox.

Other emissions associated with a forest sink project, e.g. from fuel use in machinery, should also be estimated. Preceding sections of this workbook provide relevant guidance.

6.6 Further information and advice

Further information on the National Carbon Accounting Toolbox is available at:

www.climatechange.gov.au/ncas

A free copy of the Toolbox may be obtained by emailing postal details to:

ncas@climatechange.gov.au

For more information and advice on carbon accounting for forest sinks contact:

Land Sector Policy team

Department of Climate Change

Email: gnrm@climatechange.gov.au

Appendix 1 Greenhouse Gas Global Warming Potentials

The Global Warming Potential (GWP) is an index used to convert relevant non-carbon dioxide gases to a carbon dioxide equivalent (CO₂-e) by multiplying the quantity of the gas by its GWP in the table below.*

Table 27: Global Warming Potentials

Gas	Chemical formula	Global Warming Potential
Carbon dioxide	CO ₂	1
Methane	CH ₄	21
Nitrous oxide	N ₂ O	310
Hydrofluorocarbons HFCs		
HFC-23	CHF ₃	11,700
HFC-32	CH ₂ F ₂	650
HFC-41	CH ₃ F	150
HFC-43-10mee	C ₅ H ₂ F ₁₀	1,300
HFC-125	C ₂ HF ₅	2,800
HFC-134	C ₂ H ₂ F ₄ (CHF ₂ CHF ₂)	1,000
HFC-134a	C ₂ H ₂ F ₄ (CH ₂ FCF ₃)	1,300
HFC-143	C ₂ H ₃ F ₃ (CHF ₂ CH ₂ F)	300
HFC-143a	C ₂ H ₃ F ₃ (CF ₃ CH ₃)	3,800
HFC-152a	C ₂ H ₄ F ₂ (CH ₃ CHF ₂)	140
HFC-227ea	C ₃ HF ₇	2,900
HFC-236fa	C ₃ H ₂ F ₆	6,300
HFC-245ca	C ₃ H ₃ F ₅	560
Perfluorocarbons PFCs		
Perfluoromethane (tetrafluoromethane)	CF ₄	6,500
Perfluoroethane (hexafluoroethane)	C ₂ F ₆	9,200
Perfluoropropane	C ₃ F ₈	7,000
Perfluorobutane	C ₄ F ₁₀	7,000
Perfluorocyclobutane	c-C ₄ F ₈	8,700
Perfluoropentane	C ₅ F ₁₂	7,500
Perfluorohexane	C ₆ F ₁₄	7,400
Sulphur hexafluoride	SF ₆	23,900

*These GWP factors are those specified for calculating emissions under Kyoto accounting provisions.

Appendix 2 Units and conversions

Table 28: Metric prefixes

Abbreviation	Prefix	Symbol
10^{15} ($10^6 \times 10^9$)	Peta (million billion [thousand trillion])	P
10^{12} ($10^3 \times 10^9$)	Tera (thousand billion [trillion])	T
10^9	Giga (billion)	G
10^6	Mega (million)	M
10^3	kilo (thousand)	k
10^2	hecto	h
10^1	deca	da
10^0	- (e.g. gram)	g
10^{-1}	deci	d
10^{-2}	centi	c
10^{-3}	milli	m
10^{-6}	micro	μ
10^{-9}	nano	n
10^{-12}	pico	p

Table 29: Unit equivalences

10^{15} grams (Petagram)	Gigatonne (Gt)
10^{12} grams (Teragram)	Megatonne (Mt)
10^9 grams (Gigagram)	kilotonnes (kt) (10^3 tonnes)
10^6 grams (million grams)	1 tonne
kg/GJ (10^3 g/ 10^9 J)	Gg/PJ (10^9 g/ 10^{15} J)
Mg/PJ (10^6 g/ 10^{15} J)	g/GJ 10^0 g/ 10^9 J)

e.g. 423,000 Gg is equivalent to 423,000 kt and to 423 Mt

Table 30: Energy conversion factors

Conversion factors		
1 Watt	= 1 Joule/Sec	
3600 Watt-seconds	= 1 Watt-hour (3600 seconds in one hour)	
1 Watt-hour	= 3600 Joules	
1000 Watt-hours	= 1Kilowatt hour (kWh)	
1 kWh	= 3.6×10^6 Joules = 3.6 MJ	
1 kWh	= 3.6×10^{-3} GJ	
1 GJ	= 278 kWh	
1 PJ	= 278×10^6 kWh = 278 GWh	
(A) For conversion from first unit to second unit:	(B) Multiply quantity in first unit by conversion factor:	(C) To calculate quantity in second unit:
kWh to J	kWh x 3.6×10^6	Joules
J to kWh	J x $1/3.6 \times 10^{-6}$	kWh
kWh to MJ	kWh x 3.6	MJ
MJ to kWh	MJ x 0.278	kWh
kWh to GJ	kWh x 3.6×10^{-3}	GJ
GJ to kWh	GJ x 278	kWh
kWh to PJ	kWh x 3.6×10^{-9}	PJ
PJ to kWh	PJ x 278×10^6	kWh

Table 31: Table Municipal solid waste volume to weight conversion factors

Material type	Volume to weight (t/m ³)
Paper	0.09
Textiles	0.14
Wood	0.15
Garden	0.24
Food	0.50
Sludge (wet)	0.72
Nappies	0.39
Rubber and leather	0.14

Appendix 3 Carbon content factors for fuels

Note 1 Under the 2006 IPCC Guidelines, the emission factor for CO₂ released from combustion of biogenic carbon fuels is zero.

Note 2 The carbon content factors in this Schedule do not include relevant oxidation factors.

Table 32: Carbon content factors - Solid fuels and certain coal based products

Fuel type	Carbon content factor tC/t fuel
Solid fossil fuels	
Black coal (other than that used to produce coke)	0.663
Brown coal	0.260
Coking coal	0.752
Brown coal briquettes	0.574
Coke oven coke	0.789
Coal tar	0.837
Solid fossil fuels other than those mentioned above	0.574
Fuels derived from recycled materials	
Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	0.585
Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	0.250
Primary solid biomass fuels	
Dry wood	0
Green and air dried wood	0
Sulphite lyes	0
Bagasse	0
Biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	0
Charcoal	0
Primary solid biomass fuels other than those mentioned above	0

Table 33: Carbon content factors - Gaseous fuels

Fuel type	Carbon content factor (tC/m ³ of fuel unless otherwise specified)
Gaseous fossil fuels	
Natural gas if distributed in a pipeline	5.52×10^{-4}
Coal seam methane that is captured for combustion	5.29×10^{-4}
Coal mine waste gas that is captured for combustion	5.34×10^{-4}
Compressed natural gas	5.52×10^{-4}
Unprocessed natural gas	5.52×10^{-4}
Ethane	8.87×10^{-4}
Coke oven gas	1.83×10^{-4}
Blast furnace gas	2.55×10^{-4}
Town gas	6.41×10^{-4}
Liquefied natural gas	0.355 tC/kL of fuel
Gaseous fossil fuels other than those mentioned above	5.52×10^{-4}
Biogas captured for combustion	
Landfill biogas (methane) that is captured for combustion	0
Sludge biogas (methane) that is captured for combustion	0
A biogas (methane) that is captured for combustion, other than those mentioned above	0

Table 34: Carbon content factors - Liquid fuels and certain petroleum based products

Fuel type	Carbon content factor (tC/kL of fuel unless otherwise specified)
Petroleum based oils and petroleum based greases	
Petroleum based oils (other than petroleum based oils used as fuel, eg lubricants)	0.737
Petroleum based greases	0.737
Petroleum based products other than petroleum based oils and petroleum based greases	
Crude oil including crude oil condensates	0.861 tC/t fuel
Other natural gas liquids	0.774 tC/t fuel
Gasoline (other than for use as fuel in an aircraft)	0.629
Gasoline for use as fuel in an aircraft	0.605
Kerosene (other than for use as fuel in an aircraft)	0.705
Kerosene for use as fuel in an aircraft	0.699
Heating oil	0.708

Fuel type	Carbon content factor (tC/kL of fuel unless otherwise specified)
Diesel oil	0.736
Fuel oil	0.797
Liquefied aromatic hydrocarbons	0.654
Solvents if mineral turpentine or white spirits	0.654
Liquefied petroleum gas	0.422
Naphtha	0.597
Petroleum coke	0.856 tC/t fuel
Refinery gas and liquids	0.641 tC/t fuel
Refinery coke	0.856 tC/t fuel
Bitumen	0.951 tC/t fuel
Waxes	0.871 tC/t fuel
Petroleum based products other than mentioned above	0.654
Biofuels	
Biodiesel	0
Ethanol for use as a fuel in an internal combustion engine	0
Biofuels other than those mentioned above	0

Table 35: Carbon content factors - Petroleum feedstocks and products

Fuel type	Carbon content factor (tC/t fuel unless otherwise specified)
Petrochemical feedstocks	
Carbon black if used as a petrochemical feedstock	1
Ethylene if used as a petrochemical feedstock	0.856
Petrochemical feedstock other than those mentioned in items above	0.856
Petrochemical products	
Propylene	0.856
Polyethylene	0.856
Polypropylene	0.856
Butadiene	0.888
Styrene	0.923

Appendix 4 Scope 3 emission factors

Various emission factors can be used to calculate scope 3 emissions. For ease of use, this workbook reports specific 'scope 3' emission factors for organisations that:

- burn fossil fuels: to estimate their indirect emissions attributable to the extraction, production and transport of those fuels; or
- consume purchased electricity: to estimate their indirect emissions from the extraction, production and transport of fuel burned at generation and the indirect emissions attributable to the electricity lost in delivery in the T&D network.

More broadly, scope 3 emissions can include:

- Disposal of waste generated (e.g. if the waste is transported outside the organisation and disposed of);
- Use of products manufactured and sold;
- Disposal (end of life) of products sold;
- Employee business travel (in vehicles or aircraft not owned or operated by the reporting organisation);
- Employees commuting to and from work;
- Extraction, production and transport of purchased fuels consumed;
- Extraction, production and transport of other purchased materials or goods;
- Purchase of electricity that is sold to an end user (reported by electricity retailer);
- Generation of electricity that is consumed in a T&D system (reported by end user);
- Out-sourced activities; and
- Transportation of products, materials and waste.

In some cases, scope 3 emissions from these activities can be calculated with the scope 1 emission factors provided in this document. For example, if a company decides to report on emissions from an off-site activity, and has the necessary data, then the direct (scope 1) emission factor could be used to calculate emissions, and these emissions would be reported as scope 3.

Table 36: Scope 3 emission factors –solid fuels and certain coal based products

Solid Fuels combusted	EF for scope 3
	kg CO ₂ -e/GJ
Black coal—uses other than for electricity and coking	4.6
Brown coal	0.3
Coking coal	20.7
Brown coal briquettes	10.7
Coke oven coke	8.3
Solid fossil fuels other than those mentioned above	NE

Note: NE = Not estimated

Table 37: Scope 3 emission factors –gaseous fuels

State or territory	Natural Gas EF for scope 3	Natural Gas EF for scope 3
	Small User	Large User
	kg CO ₂ -e/GJ	kg CO ₂ -e/GJ
New South Wales and ACT	16.4	15.7
Victoria	4.5	4.4
Queensland	3.5	3.2
South Australia	13.9	13.2
Western Australia	4.4	4.1
Tasmania	NE	4.4
Northern Territory	4.4	4.4

Note: Small users are defined as consuming less than 100,000 gigajoules per year

Note: NE = Not estimated

Note: Scope 3 factors for all other gaseous fuels are not estimated

Table 38: Scope 3 emission factors – liquid fuels and certain petroleum based products

Liquid Fuels combusted	EF for scope 3
	kg CO ₂ -e/GJ
Petroleum based oils (other than petroleum based oil used as fuel, eg lubricants)	5.3
Petroleum based greases	5.3
Crude oil including crude oil condensates	5.3
Other natural gas liquids	5.3
Gasoline (other than for use as fuel in an aircraft)	5.3
Gasoline for use as fuel in an aircraft (avgas)	5.3
Kerosene (other than for use as fuel in an aircraft)	5.3
Kerosene for use as fuel in an aircraft (avtur)	5.3
Heating oil	5.3
Diesel oil	5.3
Fuel oil	5.3
Liquefied aromatic hydrocarbons	5.3

Solvents if mineral turpentine or white spirits	5.3
Liquefied Petroleum Gas	5.0
Naphtha	5.3
Petroleum coke	5.3
Refinery gas and liquids	5.3
Refinery coke	5.3
Petroleum based products other than mentioned in items above	5.3
Biofuels	NE

Note: NE = Not estimated

Note: Scope 3 factors for biofuels such as biodiesels and ethanol are highly dependent on individual plant and project characteristics, and therefore have not been estimated

For further information on biofuel factors see; <http://www.btre.gov.au/info.aspx?NodId=16&ResourceId=133>

Electricity emission factors for end users

These time series estimates are provided for information. Previously published estimates were provisional and have been revised for this Workbook using emissions data in the latest state and territory greenhouse gas inventories and revised fuel consumption, interstate electricity trade and electricity transmission and distribution loss data. For most programs, the publication of these revised factors does not necessarily imply any need to revise past estimates of emissions. Previously published emission factor estimates may remain applicable and are available from the Department of Climate Change.

Table 39: Scope 2 and 3 emissions factors - consumption of purchased electricity by end users

Financial year	EF for scope 2		EF for scope 3		Full fuel cycle EF (EF for scope 2 + EF for scope 3)	
	A	B	C	D	E	F
	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ
NEW SOUTH WALES and AUSTRALIAN CAPITAL TERRITORY						
1990	0.90	250	0.16	45	1.06	295
1995	0.86	239	0.16	44	1.02	284
2000	0.87	241	0.17	46	1.03	287
2005	0.89	247	0.17	46	1.06	294
2006	0.89	247	0.17	47	1.06	294
2007	0.89	248	0.18	49	1.07	297
Latest estimate	0.89	249	0.18	49	1.07	298
VICTORIA						
1990	1.24	345	0.21	58	1.45	403
1995	1.25	346	0.15	40	1.39	387
2000	1.30	360	0.12	33	1.42	394
2005	1.26	349	0.06	17	1.32	365
2006	1.24	344	0.08	21	1.32	366
2007	1.23	342	0.11	29	1.34	371

Financial year	EF for scope 2		EF for scope 3		Full fuel cycle EF (EF for scope 2 + EF for scope 3)	
	A	B	C	D	E	F
	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ
Latest estimate	1.22	340	0.12	34	1.35	374
QUEENSLAND						
1990	0.96	268	0.13	36	1.10	304
1995	0.97	271	0.13	36	1.10	307
2000	0.92	255	0.13	37	1.05	292
2005	0.90	251	0.14	38	1.04	289
2006	0.91	252	0.13	36	1.04	288
2007	0.90	250	0.12	34	1.02	284
Latest estimate	0.89	247	0.12	34	1.01	281
SOUTH AUSTRALIA						
1990	0.81	225	0.20	56	1.01	281
1995	0.87	241	0.19	52	1.05	292
2000	0.92	257	0.17	46	1.09	303
2005	0.89	247	0.15	42	1.04	289
2006	0.87	241	0.13	37	1.00	278
2007	0.83	231	0.15	40	0.98	271
Latest estimate	0.77	215	0.14	40	0.92	255
WESTERN AUSTRALIA—South-West Interconnected System (SWIS)						
1990	0.91	253	0.16	46	1.08	299
1995	0.92	256	0.14	40	1.07	296
2000	0.92	256	0.12	34	1.04	290
2005	0.85	235	0.10	29	0.95	264
2006	0.85	236	0.10	28	0.95	264
2007	0.84	234	0.10	27	0.94	261
Latest estimate	0.84	234	0.10	27	0.94	262
TASMANIA						
1990	0.06	17	0.01	3	0.07	21
1995	0.02	5	0.00	1	0.02	6
2000	0.01	2	0.00	0	0.01	2
2005	0.04	10	0.01	2	0.04	12
2006	0.05	13	0.01	2	0.06	15
2007	0.13	35	0.01	4	0.14	39
Latest Estimate	0.23	63	0.02	4	0.24	68
NORTHERN TERRITORY						
2006	0.69	192	0.10	29	0.80	221
2007	0.68	190	0.11	32	0.80	222
Latest Estimate	0.68	188	0.11	32	0.79	219

Notes:

- These time series estimates are provided for information. Previously published estimates were provisional and have been revised for this Workbook using emissions data in the latest state and territory greenhouse gas

inventories and revised fuel consumption, interstate trade and transmission and distribution loss data. For most programs, the publication of these revised factors does not necessarily imply any need to revise past estimates of emissions. Previously published emission factor estimates may remain applicable and are available from the Department of Climate Change.

- Emission factors are representative of the state's primary electricity grid. To minimise volatility emission factors are calculated as a three-year average.
- Latest estimate based on NEMMCO data
- Scope 3 emission factors for transmission and distribution network operators are lower as they include only emissions attributable to the extraction, production and transport of fuels and not emissions attributable to the electricity lost in transmission and distribution networks. Transmission and distribution network operators should use the scope 2 factors in the table above and the following scope 3 factors for 2008: NSW and ACT: 0.07kg CO₂-e/kWh, VIC: 0.01kg CO₂-e/kWh, QLD: 0.02kg CO₂-e/kWh, SA: 0.06kg CO₂-e/kWh, WA: 0.03kg CO₂-e/kWh, TAS: 0.004kg CO₂-e/kWh, NT:0.05 kg CO₂-e/kWh.
- Data are for financial years ending in June.
- Sources: Department of Climate Change estimates derived from George Wilkenfeld and Associates (2008). Primary data sources comprise generator survey returns to the Department of Climate Change, ABARE, ESAA and NEMMCO data.

Emissions from waste disposal to landfill and wastewater treatment

Methane (CH₄) vented to the atmosphere is considered an emission as this action would be adding to atmospheric CH₄. The emissions are multiplied by 21 to calculate the carbon dioxide equivalent (CO₂-e) emissions.

Where methane from waste biomass is recovered and flared or combusted for energy, the CO₂ emitted is not counted as an emission but regarded as part of the natural carbon cycle. The total amount of CH₄ recovered is therefore regarded as saved (not emitted) so long as it does not enter the atmosphere as CH₄.

Where waste material is diverted from landfill to recycling or to energy use, the reporting organisation will have less emissions attributed to its activities because less waste is going to landfill.

Municipal solid waste

Estimates of Scope 3 greenhouse gas emissions associated with the disposal of waste can be calculated according to the general equation:

$$\text{GHG emissions (t CO}_2\text{-e)} = Q_j \times \text{EF}_j$$

where:

Q_j is the quantity of waste by type j

EF_j is the emission factor of waste type j (see Table 40, column B)

Organisations that do not know the composition of their waste can use the emission factors in Table 42, which gives the weighted average emission factors for the municipal, commercial and industrial, and construction and demolition waste categories.

Table 40: Waste mix methane conversion factors

Waste types	Default DOC proportion	Conversion factor CO ₂ -e (t=tonnes)
	A	B
Food	0.15	t x 0.9
Paper and cardboard	0.4	t x 2.5
Garden and green	0.2	t x 1.3
Wood	0.43	t x 2.7
Textiles	0.24	t x 1.5
Sludge	0.05	t x 0.3
Nappies	0.24	t x 1.5
Rubber and leather	0.39	t x 2.5
Inert waste (including concrete/metal/plastics/glass)	0	t x 0

Note: Source National Greenhouse and Energy Reporting System Measurement Technical Guidelines June 2009. The proportions represent the quantity of DOC of the various waste types in the mix that may be available for conversion to methane.

If waste is measured by volume and not by weight, conversion factors are available in Appendix 2.

The emission factors in column B of Table 40 have been calculated according to the default variables detailed in Table 41 and the following formula:

$$\text{GHG Emissions (t CO}_2\text{-e)} = [((Q \times \text{DOC} \times \text{DOC}_F \times F_1 \times 16/12) - R) \times (1 - \text{OX})] \times 21$$

Table 41: Waste variables and default values

Variable	Default values
Q (Activity)	Quantity of municipal solid waste expressed in tonnes and sourced from waste records or contractor invoices
DOC	Degradable Organic Carbon expressed as a proportion of the particular waste type and contained in Table 41.
DOC _F	Fraction of degradable organic carbon dissimilated for the waste type produced with a default value of 0.5.
F ₁	Methane fraction of landfill gas which has a default value of 0.50
16/12	Conversion rate of carbon to methane
R	Recovered methane during the year, measured/expressed in tonnes
OX	Oxidation factor which has a default value of 0.1 for covered, well-managed landfills (and a value of 0 for uncovered landfills)
21	CH ₄ global warming potential used to convert the quantity of methane emitted to CO ₂ -e from the quantity of waste produced

Note: The CH₄ recovered must be subtracted from the amount generated before applying the oxidation factor because only the landfill gas that is not captured is subject to oxidation.

Table 42: Waste emission factors for total waste disposed to landfill by broad waste stream category

Waste types	Municipal solid waste	Commercial and industrial waste	Construction and demolition waste
	A	B	C
Emission factor (t CO ₂ -e/t waste)	1.0	1.1	0.3

Note: Organisations that have data on their own waste streams and waste mix should use that data.

Source: Derived from National Greenhouse and Energy Reporting (Measurement) Determination 2008.

Example: Calculation of emissions generated from solid waste

A higher education facility produced a total solid waste stream of 240 tonnes which was disposed of in the local landfill. This waste comprises 140 tonnes of food waste, 50 tonnes of paper/paper board, 10 tonnes of garden and park waste and 40 tonnes of inert waste. No methane (R) was recovered. As each waste stream needs to be treated separately, their greenhouse gas emissions (GHG) are calculated as follows:

GHG emissions (t CO₂-e) = Qt x EF (Table 40, Column B)

Food = 140 x 0.9 = 126 tonnes CO₂-e

Paper = 50 x 2.5 = 125 tonnes CO₂-e

Garden = 10 x 1.3 = 13 tonnes CO₂-e

$$\text{inert} = 40 \times 0 = 0 \text{ tonnes CO}_2\text{-e}$$

Total Waste GHG emissions = 264 t CO₂-e

Example: Calculation of emissions generated from waste of unknown composition

A commercial company in the finance industry disposes 1 kilotonne of commercial and industrial waste.

$$\text{GHG emissions (t CO}_2\text{-e)} = Q \times \text{EF (Table 42, Column B)} = 1000 \text{ t} \times 1.1 = 1100 \text{ t CO}_2\text{-e}$$

Wastewater handling (domestic and commercial)

Total greenhouse gas emissions from municipal wastewater are the sum of emissions from wastewater treatment and sludge treatment. The total quantity of wastewater treated depends on the population that is generating wastewater.

The following formula should be used to measure the CO₂-e emissions from treating municipal wastewater. This formula is most relevant to local government authorities.

$$\text{GHG Emissions (t CO}_2\text{-e)} = [(((P \times \text{DC}_w) \times (1 - F_{sl}) \times F_{an} \times \text{EF}_w)) + (P \times \text{DC}_w \times F_{sl} \times \text{EF}_{sl}) - R] \times 21$$

The parameters used in the above equation are explained in Table 43 together with a listing of the various default values.

Example: Calculation of emissions generated from municipal wastewater

A local government wastewater treatment plant services a population of 20,000 people. The treatment process is characterised as a deep anaerobic lagoon. Based on internal records, the average amount of BOD that is removed and treated as sludge in an anaerobic digester is 0.54. The treatment plant recovers all the methane generated in the anaerobic digester.. Their CO₂-e greenhouse gas emissions are calculated as follows:

BOD calculation:

$$\begin{aligned} \text{BOD}_w \text{ (tonnes)} &= \text{Population} \times \text{DC}_w / 1000 \\ &= 20,000 \times 22.5 / 1000 \\ &= 450 \text{ tonnes BOD} \end{aligned}$$

Emissions from wastewater treatment calculation:

$$\begin{aligned} \text{GHG emissions (tonnes CO}_2\text{-e)} &= \text{BOD} \times (1 - F_{sl}) \times F_{an} \times \text{EF}_w \times 21 \\ &= 450 \times (1 - 0.54) \times 0.8 \times 0.65 \times 21 \\ &= 2260.4 \text{ tonnes CO}_2\text{-e} \end{aligned}$$

Emissions from sludge calculation:

$$\begin{aligned} \text{GHG emissions (tonnes CO}_2\text{-e)} &= \text{BOD} \times F_{sl} \times \text{EF}_{sl} \times 21 = 450 \times 0.54 \times 0.8 \times 0.65 \times 21 \\ &= 2653.6 \text{ tonnes CO}_2\text{-e} \end{aligned}$$

Total emissions:

Accounting for the recovery of methane, the sum of wastewater and sludge GHG emissions = 2860.4 tonnes CO₂-e

Table 43: Municipal waste variables and default values

Variable	Default values
P	The population served and measured in 1000 persons and sourced from waste treatment records
DC _w	The quantity in kilograms of Biochemical Oxygen Demand (BOD) per capita per year of wastewater. In the event that no waste analysis data is available, a default value of 22.5 kg per person per year can be used
BOD _w	Biochemical Oxygen Demand (BOD) in kilograms of BOD per year which is the product of DC _w and population
F _{sl}	Default fraction of BOD removed as sludge. Should be readily available from internal records of wastewater treatment plants (default value of 0.29)
EF _w	Default methane emission factor for wastewater with value of 0.65 kg CH ₄ /kg BOD
EF _{sl}	Default methane emission factor for sludge with value of 0.65 kg CH ₄ /kg BOD (sludge)
F _{an}	Fraction of BOD anaerobically treated. This value varies according to wastewater treatment type. IPCC defaults are: Managed aerobic treatment – 0 Unmanaged aerobic treatment – 0.3 Anaerobic digester/reactor – 0.8 Shallow anaerobic lagoon (<2 metres) – 0.2 Deep anaerobic lagoon (>2 metres)– 0.8
CH ₄ - GWP	21 – the Global Warming Potential of CH ₄ used to convert the CH ₄ emitted from wastewater to CO ₂ -e
R	Recovered methane from wastewater in an inventory year, measured/expressed in tonnes

Appendix 5 Revisions to factors from previous issue

- Ethane – energy content (Table 2, page 13):

Revised value (GJ/m ³)	Previous value (GJ/m ³)
62.9x10 ⁻³	57.5x10 ⁻³

- Electricity – scope 2 and 3 emission factors 2007 (Table 39, page 61):

State or territory	EF for scope 2				EF for scope 3			
	Revised values		Previous values		Revised values		Previous values	
	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ
New South Wales and ACT	0.89	248	0.89	249	0.18	49	0.17	47
Victoria	1.23	342	1.22	340	0.11	29	0.08	23
Queensland	0.90	250	0.91	252	0.12	34	0.13	38
South Australia	0.83	231	0.84	233	0.15	40	0.14	39
Western Australia (SWIS)	0.84	234	0.87	242	0.10	27	0.10	29
Tasmania	0.13	35	0.12	35	0.01	4	0.01	2
Northern Territory	0.68	190	-	-	0.11	32	-	-

- Electricity – scope 2 and 3 emission factors 2006 (Table 39, page 61):

State or territory	EF for scope 2				EF for scope 3			
	Revised values		Previous values		Revised values		Previous values	
	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ	kg CO ₂ -e/kWh	kg CO ₂ -e/GJ
South Australia	0.87	241	0.87	242	0.13	37	0.14	39
Northern Territory	0.69	192	-	-	0.10	29	-	-

- “Latest estimate” (2008) scope 2 and scope 3 emission factors have also been added to table 39 on page 61

- Natural Gas – scope 3 emission factors (Table 37, page 60):

State or territory	Natural Gas EF for scope 3		Natural Gas EF for scope 3	
	Small User		Large User	
	Revised value (kg CO ₂ -e/GJ)	Previous value (kg CO ₂ -e/GJ)	Revised value (kg CO ₂ -e/GJ)	Previous value (kg CO ₂ -e/GJ)
New South Wales and ACT	16.4	14.8	15.7	14.2
Victoria	4.5	5.9	4.4	5.8
Queensland	3.5	6	3.2	5.4
South Australia	13.9	19.4	13.2	18.6
Western Australia	4.4	7.6	4.1	7
Tasmania	NE	NE	4.4	5.8
Northern Territory	4.4	5.7	4.4	5.7

- Liquefied Petroleum Gas – scope 3 emission factors (Table 38, page 60):

Revised value (kg CO ₂ -e/GJ)	Previous value (kg CO ₂ -e/GJ)
5.0	5.3

- Solid Waste – scope 3 conversion factors by waste stream (Table 4, page 65):

Municipal solid waste		Commercial and industrial waste	
Revised value (t CO ₂ -e/t waste)	Previous value (t CO ₂ -e/t waste)	Revised value (t CO ₂ -e/t waste)	Previous value (t CO ₂ -e/t waste)
1.0	1.3	1.1	1.7