National Greenhouse and Energy Reporting (Measurement) Determination 2008

made under subsection 10(3) of the

National Greenhouse and Energy Reporting Act 2007

Compilation No. 10

Compilation date:	1 July 2018
Includes amendments up to:	F2018L00923
Registered:	5 July 2018

Prepared by the Office of Parliamentary Counsel, Canberra

About this compilation

This compilation

This is a compilation of the *National Greenhouse and Energy Reporting (Measurement) Determination 2008* that shows the text of the law as amended and in force on 1 July 2018 (the ***compilation date***).

The notes at the end of this compilation (the ***endnotes***) include information about amending laws and the amendment history of provisions of the compiled law.

Uncommenced amendments

The effect of uncommenced amendments is not shown in the text of the compiled law. Any uncommenced amendments affecting the law are accessible on the Legislation Register (www.legislation.gov.au). The details of amendments made up to, but not commenced at, the compilation date are underlined in the endnotes. For more information on any uncommenced amendments, see the series page on the Legislation Register for the compiled law.

Application, saving and transitional provisions for provisions and amendments

If the operation of a provision or amendment of the compiled law is affected by an application, saving or transitional provision that is not included in this compilation, details are included in the endnotes.

Editorial changes

For more information about any editorial changes made in this compilation, see the endnotes.

Modifications

If the compiled law is modified by another law, the compiled law operates as modified but the modification does not amend the text of the law. Accordingly, this compilation does not show the text of the compiled law as modified. For more information on any modifications, see the series page on the Legislation Register for the compiled law.

Self-repealing provisions

If a provision of the compiled law has been repealed in accordance with a provision of the law, details are included in the endnotes.

Contents

Chapter 1—General

Part 1.1—Preliminary

1.1 Name of Determination

This Determination is the *National Greenhouse and Energy Reporting (Measurement) Determination 2008*.

Division 1.1.1—Overview

1.3 Overview—general

(1) This determination is made under section 10 of the *National Greenhouse and Energy Reporting Act 2007*. It provides for the measurement of the following:
  (a) greenhouse gas emissions arising from the operation of facilities;
  (b) the production of energy arising from the operation of facilities;
  (c) the consumption of energy arising from the operation of facilities.

Note: ***Facility*** has the meaning given by section 9 of the Act.

(2) This determination deals with scope 1 emissions and scope 2 emissions.

Note: ***Scope 1 emission*** and ***scope 2 emission*** have the meaning given by section 10 of the Act (also see, respectively, regulations 2.23 and 2.24 of the Regulations).

(3) There are 4 categories of scope 1 emissions dealt with in this Determination.

Note: This Determination does not deal with emissions released directly from land management.

(4) The categories of scope 1 emissions are:
  (a) fuel combustion, which deals with emissions released from fuel combustion (see Chapter 2); and
  (b) fugitive emissions from fuels, which deals with emissions mainly released from the extraction, production, processing and distribution of fossil fuels (see Chapter 3); and
  (c) industrial processes emissions, which deals with emissions released from the consumption of carbonates and the use of fuels as feedstock or as carbon reductants, and the emission of synthetic gases in particular cases (see Chapter 4); and
  (d) waste emissions, which deals with emissions mainly released from the decomposition of organic material in landfill or other facilities, or wastewater handling facilities (see Chapter 5).

(5) Each of the categories has various subcategories.

1.4 Overview—methods for measurement

(1) This Determination provides methods and criteria for the measurement of the matters mentioned in subsection 1.3(1).

(2) For scope 1 emissions or scope 2 emissions:
- (a) method 1 (known as the default method) is derived from the National Greenhouse Accounts methods and is based on national average estimates; and
- (b) method 2 is generally a facility specific method using industry practices for sampling and Australian or equivalent standards for analysis; and
- (c) method 3 is generally the same as method 2 but is based on Australian or equivalent standards for both sampling and analysis; and
- (d) method 4 provides for facility specific measurement of emissions by continuous or periodic emissions monitoring.

Note: Method 4, that applies as indicated by provisions of this Determination, is as set out in Part 1.3.

1.5 Overview—energy

Chapter 6 deals with the estimation of the production and consumption of energy.

1.6 Overview—scope 2 emissions

Chapter 7 deals with scope 2 emissions.

1.7 Overview—assessment of uncertainty

Chapter 8 deals with the assessment of uncertainty.

Division 1.1.2—Definitions and interpretation

1.8 Definitions

In this Determination:

2006 IPCC Guidelines means the *2006 IPCC Guidelines for National Greenhouse Gas Inventories* published by the IPCC.

ACARP Guidelines means the document entitled *Guidelines for the Implementation of NGER Method 2 or 3 for Open Cut Coal Mine Fugitive GHG Emissions Reporting* (C20005), published by the Australian Coal Association Research Program in December 2011.

accredited laboratory means a laboratory accredited by the National Association of Testing Authorities or an equivalent member of the International Laboratory Accreditation Cooperation in accordance with AS ISO/IEC 17025:2005, and for the production of calibration gases, accredited to ISO Guide 34:2000.

Act means the *National Greenhouse and Energy Reporting Act 2007*.

active gas collection means a system of wells and pipes that collect landfill gas through the use of vacuums or pumps.

alternative waste treatment activity means an activity that:

(a) accepts and processes mixed waste using:
  (i) mechanical processing; and
  (ii) biological or thermal processing; and
(b) extracts recyclable materials from the mixed waste.

alternative waste treatment residue means the material that remains after waste has been processed and organic rich material has been removed by physical screening or sorting by an alternative waste treatment activity that produces compost, soil conditioners or mulch in accordance with:

(a) State or Territory legislation; or
(b) Australian Standard AS 4454:2012.

ANZSIC industry classification and code means an industry classification and code for that classification published in the Australian and New Zealand Standard Industrial Classification (ANZSIC), 2006.

APHA followed by a number means a method of that number issued by the American Public Health Association and, if a date is included, of that date.

API Compendium means the document entitled *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry*, published in August 2009 by the American Petroleum Institute.

Note: The API Compendium is available at www.api.org.

applicable State or Territory legislation, for an underground mine, means a law of a State or Territory in which the mine is located that relates to coal mining health and safety, including such a law that prescribes performance-based objectives, as in force on 1 July 2008.

Note: Applicable State or Territory legislation includes:

- *Coal Mine Health and Safety Act 2002* (NSW) and the *Coal Mine Health and Safety Regulation 2006* (NSW)
- *Coal Mining Safety and Health Act 1999* (Qld) and the *Coal Mining Safety and Health Regulation 2001* (Qld).

appropriate standard, for a matter or circumstance, means an Australian standard or an equivalent international standard that is appropriate for the matter or circumstance.

appropriate unit of measurement, in relation to a fuel type, means:

(a) for solid fuels—tonnes; and
(b) for gaseous fuels—metres cubed or gigajoules, except for liquefied natural gas which is kilolitres; and
(c) for liquid fuels other than those mentioned in paragraph (d)—kilolitres; and
(d) for liquid fuels of one of the following kinds—tonnes:
  (i) crude oil, including crude oil condensates, other natural gas liquids;
  (ii) petroleum coke;
  (iii) refinery gas and liquids;
  (iv) refinery coke;
  (v) bitumen:
  (vi) waxes;
  (vii) carbon black if used as petrochemical feedstock;
  (viii) ethylene if used as a petrochemical feedstock;
  (ix) petrochemical feedstock mentioned in item 57 of Schedule 1 to the Regulations.

AS or ***Australian standard*** followed by a number (for example, AS 4323.1—1995) means a standard of that number issued by Standards Australia Limited and, if a date is included, of that date.

ASTM followed by a number (for example, ASTM D6347/D6347M-99) means a standard of that number issued by ASTM International and, if a date is included, of that date.

Australian legal unit of measurement has the meaning given by the *National Measurement Act 1960.*

base of the low gas zone means the part of the low gas zone worked out in accordance with section 3.25A.

basin means a geological basin named in the *Australian Geological Provinces Database*.

Note: The *Australian Geological Provinces Database* is available at www.ga.gov.au.

biogenic carbon fuel means energy that is:

(a) derived from plant and animal material, such as wood from forests, residues from agriculture and forestry processes and industrial, human or animal wastes; and

(b) not embedded in the earth for example, like coal oil or natural gas.

biological treatment of solid waste:

(a) means an alternative waste treatment activity consisting of a composting or anaerobic digestion process in which organic matter in solid waste is broken down by microorganisms; but

(b) does not include solid waste disposal in a landfill.

Note: Chapter 5 (waste) deals with solid waste disposal in a landfill as well as the biological treatment of solid waste (whether at a landfill or at a facility elsewhere).

blended fuel means fuel that is a blend of fossil and biogenic carbon fuels.

briquette means an agglomerate formed by compacting a particulate material in a briquette press, with or without added binder material.

calibrated to a measurement requirement, for measuring equipment, means calibrated to a specific characteristic, for example a unit of weight, with the characteristic being traceable to:

(a) a measurement requirement provided for under the *National Measurement Act 1960* or any instrument under that Act for that equipment; or

(b) a measurement requirement under an equivalent standard for that characteristic.

captured for permanent storage, in relation to a greenhouse gas, has the meaning given by section 1.19A.

CEM or ***continuous emissions monitoring*** means continuous monitoring of emissions in accordance with Part 1.3.

CEN/TS followed by a number (for example, CEN/TS 15403) means a technical specification (TS) of that number issued by the European Committee for Standardization and, if a date is included, of that date.

CO_2-e means carbon dioxide equivalence.

coal seam methane has the same meaning as in the Regulations.

COD or ***chemical oxygen demand*** means the total material available for chemical oxidation (both biodegradable and non-biodegradable) measured in tonnes.

compressed natural gas has the meaning given by the Regulations.

core sample means a cylindrical sample of the whole or part of a strata layer, or series of strata layers, obtained from drilling using a coring barrel with a diameter of between 50 mm and 2 000 mm.

crude oil condensates has the meaning given by the Regulations.

crude oil transport means the transportation of marketable crude oil to heavy oil upgraders and refineries by means that include the following:

(a) pipelines;
(b) marine tankers;
(c) tank trucks;
(d) rail cars.

decommissioned underground mine has the meaning given by the Regulations.

detection agent has the same meaning as in the *Offshore Petroleum and Greenhouse Gas Storage Act 2006*.

documentary standard means a published standard that sets out specifications and procedures designed to ensure that a material or other thing is fit for purpose and consistently performs in the way it was intended by the manufacturer of the material or thing.

domain, of an open cut mine, means an area, volume or coal seam in which the variability of gas content and the variability of gas composition in the open cut mine have a consistent relationship with other geological, geophysical or spatial parameters located in the area, volume or coal seam.

dry wood has the meaning given by the Regulations.

efficiency method has the meaning given by subsection 2.70(2).

EN followed by a number (for example, EN 15403) means a standard of that number issued by the European Committee for Standardization and, if a date is included, of that date.

enclosed composting activity means a semi-enclosed or enclosed alternative waste or composting technology where the composting process occurs within a reactor that:

(a) has hard walls or doors on all 4 sides; and
(b) sits on a floor; and
(c) has a permanent positive or negative aeration system.

energy content factor, for a fuel, means gigajoules of energy per unit of the fuel measured as gross calorific value.

estimator, of fugitive emissions from an open cut mine using method 2 under section 3.21 or method 3 under section 3.26, means:

(a) an individual who has the minimum qualifications of an estimator set out in the ACARP Guidelines; or
(b) individuals who jointly have those minimum qualifications.

extraction area, in relation to an open cut mine, is the area of the mine from which coal is extracted.

feedstock has the meaning given by the Regulations.

ferroalloy has the meaning given by subsection 4.69(2).

flaring means the combustion of fuel for a purpose other than producing energy.

Example: The combustion of methane for the purpose of complying with health, safety and environmental requirements.

fuel means a substance mentioned in column 2 of an item in Schedule 1 to the Regulations other than a substance mentioned in items 58 to 66.

fuel oil has the meaning given by the Regulations.

fugitive emissions has the meaning given by the *Clean Energy Regulations 2011*.

gas bearing strata is coal and carbonaceous rock strata:

(a) located in an open cut mine; and
(b) that has a relative density of less than 1.95 g/cm^3.

gaseous fuel means a fuel mentioned in column 2 of items 17 to 30 of Schedule 1 to the Regulations.

gas stream means the flow of gas subject to monitoring under Part 1.3.

gassy mine means an underground mine that has at least 0.1% methane in the mine's return ventilation.

Global Warming Potential means, in relation to a greenhouse gas mentioned in column 2 of an item in the table in regulation 2.02 of the Regulations, the value mentioned in column 4 for that item.

GPA followed by a number means a standard of that number issued by the Gas Processors Association and, if a date is included, of that date.

green and air dried wood has the meaning given by the Regulations.

greenhouse gas stream means a stream consisting of a mixture of any or all of the following substances captured for injection into, and captured for permanent storage in, a geological formation:

(a) carbon dioxide, whether in a gaseous or liquid state;
(b) a greenhouse gas other than carbon dioxide, whether in a gaseous or liquid state;
(c) one or more incidental greenhouse gas-related substances, whether in a gaseous or liquid state, that relate to either or both of the greenhouse gases mentioned in paragraph (a) and (b);
(d) a detection agent, whether in a gaseous or liquid state;

so long as:

(e) the mixture consists overwhelmingly of either or both of the greenhouse gases mentioned in paragraphs (a) and (b); and
(f) if the mixture includes a detection agent—the concentration of the detection agent in the mixture is not more than the concentration prescribed in relation to the detection agent for the purposes of subparagraph (vi) of

paragraph (c) of the definition of ***greenhouse gas substance*** in section 7 of the *Offshore Petroleum and Greenhouse Gas Storage Act 2006*.

Note: A greenhouse gas is ***captured for permanent storage*** in a geological formation if the gas is captured by, or transferred to, the holder of a licence, lease or approval mentioned in section 1.19A, under a law mentioned in that section, for the purpose of being injected into a geological formation (however described) under the licence, lease or approval.

GST group has the same meaning as in the *Fuel Tax Act 2006*.

GST joint venture has the same meaning as in the *Fuel Tax Act 2006*.

higher method has the meaning given by subsection 1.18(5).

hydrofluorocarbons has the meaning given by section 4.99.

ideal gas law means the state of a hypothetical ideal gas in which the amount of gas is determined by its pressure, volume and temperature.

IEC followed by a number (for example, IEC 17025:2005) means a standard of that number issued by the International Electrotechnical Commission and, if a date is included, of that date.

incidental, for an emission, has the meaning given by subregulation 4.27(5) of the Regulations.

incidental greenhouse gas-related substance, in relation to a greenhouse gas that is captured from a particular source material, means:

(a) any substance that is incidentally derived from the source material; or
(b) any substance that is incidentally derived from the capture; or
(c) if the captured greenhouse gas, whether in a pure form or in a mixture with other substances, is transported—any substance that is incidentally derived from the transportation; or
(d) if the captured greenhouse gas, whether in a pure form or in a mixture with other substances, is injected into a part of a geological formation—any substance that is incidentally derived from the injection; or
(e) if the captured greenhouse gas, whether in a pure form or in a mixture with other substances, is stored in a part of a geological formation—any substance that is incidentally derived from the storage.

independent expert, in relation to an operator of a landfill, means a person who:

(a) is independent of the operator of the landfill; and
(b) has relevant expertise in estimating or monitoring landfill surface gas.

inert waste means waste materials that contain no more than a negligible volume of degradable organic carbon and includes the following waste:

(a) concrete;
(b) metal;
(c) plastic;
(d) glass;

(e) asbestos concrete;
(f) soil.

integrated metalworks has the meaning given by subsection 4.64(2).

invoice includes delivery record.

IPCC is short for Intergovernmental Panel on Climate Change established by the World Meteorological Organization and the United Nations Environment Programme.

ISO followed by a number (for example, ISO 10396:2007) means a standard of that number issued by the International Organization of Standardization and, if a date is included, of that date.

legacy emissions has the same meaning as in the *National Greenhouse and Energy Reporting (Safeguard Mechanism) Rule 2015*.

legacy waste means waste deposited at a landfill before 1 July 2016.

liquefied natural gas has the same meaning as in the Regulations.

liquefied petroleum gas has the same meaning as in the Regulations.

liquid fuel means a fuel mentioned in column 2 of items 31 to 54 of Schedule 1 to the Regulations.

lower method has the meaning given by subsection 1.18(6).

low gas zone means the part of the gas bearing strata of an open cut mine:
(a) that is located immediately below the original surface of the mine and above the base of the low gas zone; and
(b) the area of which is worked out by working out the base of the low gas zone.

main electricity grid has the meaning given by subsection 7.2(4).

marketable crude oil includes:
(a) conventional crude oil; and
(b) heavy crude oil; and
(c) synthetic crude oil; and
(d) bitumen.

method means a method specified in this determination for estimating emissions released from the operation of a facility in relation to a source.

municipal materials has the meaning given by the Regulations.

municipal solid waste class I means waste from domestic premises, council collections and other municipal sources where:
(a) the collection of organic waste on a regular basis in a dedicated bin is not provided to residents of the municipality as a standard practice; or

(b) the collection of organic waste on a regular basis in a dedicated bin provided to residents of the municipality cannot be confirmed as standard practice.

municipal solid waste class II means waste from domestic premises, council collections and other municipal sources where a bin dedicated for garden waste is:

(a) provided to residents of the municipality as a standard practice; and
(b) collected on a regular basis.

N/A means not available.

National Greenhouse Accounts means the set of national greenhouse gas inventories, including the National Inventory Report 2005, submitted by the Australian government to meet its reporting commitments under the United Nations Framework Convention on Climate Change and the 1997 Kyoto Protocol to that Convention.

natural gas has the meaning given by the Regulations.

natural gas distribution is distribution of natural gas through low-pressure pipelines with pressure of 1 050 kilopascals or less.

natural gas liquids has the meaning given by the Regulations.

natural gas transmission is transmission of natural gas through high-pressure pipelines with pressure greater than 1 050 kilopascals.

non-gassy mine means an underground mine that has less than 0.1% methane in the mine's return ventilation.

non-legacy waste means waste deposited at a landfill on or after 1 July 2016.

open cut mine:

(a) means a mine in which the overburden is removed from coal seams to allow coal extraction by mining that is not underground mining; and
(b) for method 2 in section 3.21 or method 3 in section 3.26—includes a mine of the kind mentioned in paragraph (a):
    (i) for which an area has been established but coal production has not commenced; or
    (ii) in which coal production has commenced.

PEM or ***periodic emissions monitoring*** means periodic monitoring of emissions in accordance with Part 1.3.

Perfluorocarbon protocol means the *Protocol for Measurement of Tetrafluoromethane* (CF_4) *and Hexafluoroethane* (C_2F_6) *Emissions from Primary Aluminium Production* published by the United States Environmental Protection Agency and the International Aluminium Institute.

petroleum based greases has the meaning given by regulation 1.03 of the Regulations.

petroleum based oils has the meaning given by the Regulations.

petroleum coke has the meaning given by the Regulations.

phytocap means an evapotranspiration landfill capping system that makes use of soil and vegetation to store and release surface water.

post-mining activities, in relation to a mine, is the handling, stockpiling, processing and transportation of coal extracted from the mine.

primary wastewater treatment plant:

(a) means a treatment facility at which wastewater undergoes physical screening, degritting and sedimentation; and
(b) does not include a treatment facility at which any kind of nitrification or denitrification treatment process occurs.

principal activity, in relation to a facility, means the activity that:

(a) results in the production of a product or service that is produced for sale on the market; and
(b) produces the most value for the facility out of any of the activities forming part of the facility.

pyrolysis of coal means the decomposition of coal by heat.

raw sugar has the meaning given by Chapter 17 of Section IV of Schedule 3 to the *Customs Tariff Act 1995.*

reductant:

(a) means a reducing agent or substance:
    (i) that causes another substance to undergo reduction; and
    (ii) that is oxidised while causing the substance to undergo reduction; and
(b) does not include fuels that are combusted only to produce energy.

refinery gases and liquids has the meaning given by the Regulations.

Regulations means the *National Greenhouse and Energy Reporting Regulations 2008*.

relevant person means a person mentioned in paragraph 1.19A(a), (b), (c), (d), (e) or (f).

run-of-mine coal means coal that is produced by mining operations before screening, crushing or preparation of the coal has occurred.

scope 1 emissions has the same meaning as in the Regulations.

scope 2 emissions has the same meaning as in the Regulations.

separate instance of a source has the meaning given by section 1.9A.

separate occurrence of a source has the meaning given by section 1.9B.

shale gas means a substance that:

(a) consists of:
  (i) naturally occurring hydrocarbons; or
  (ii) a naturally occurring mixture of hydrocarbons and non-hydrocarbons; and
(b) consists mainly of methane; and
(c) is drained from shale formations.

shredder flock means the residual waste generated from the process of scrap metal processing that ends up in landfill.

sludge biogas has the meaning given by the Regulations.

sludge lagoon means a component of a wastewater treatment system that:
(a) is used to stabilise and dry excess or wasted sludge from the liquid or solid phase treatment train of a wastewater treatment plant; and
(b) involves biodegradation of COD in the form of sludge and the use of ambient climatic factors to reduce the moisture content of the sludge.

solid fuel means a fuel mentioned in column 2 of items 1 to 16 of Schedule 1 to the Regulations.

source has the meaning given by section 1.10.

specified taxable fuel has the meaning given by regulation 3.30 of the *Clean Energy Regulations 2011*.

standard includes a protocol, technical specification or USEPA method.

standard conditions has the meaning given by subsection 2.32(7).

sulphite lyes has the meaning given by the Regulations.

supply means supply by way of sale, exchange or gift.

synthetic gas generating activities has the meaning given by subsections 4.100(1) and (2).

technical guidelines means the document published by the Department and known as the *National Greenhouse Energy and Reporting (Measurement) Technical Guidelines 2009*.

tight gas means a substance that:
(a) consists of:
  (i) naturally occurring hydrocarbons; or
  (ii) a naturally occurring mixture of hydrocarbons and non-hydrocarbons; and
(b) consists mainly of methane; and
(c) is drained from low permeability sandstone and limestone reservoirs.

uncertainty protocol means the publication known as the *GHG protocol guidance on uncertainty assessment in GHG inventories and calculating* *statistical parameter uncertainty* (September 2003) v1.0 issued by the World Resources Institute and the World Business Council for Sustainable Development.

underground mine means a coal mine that allows extraction of coal by mining at depth, after entry by shaft, adit or drift, without the removal of overburden.

USEPA followed by a reference to a method (for example, Method 3C) means a standard of that description issued by the United States Environmental Protection Agency.

waxes has the meaning given by the Regulations.

well completion means the period that:

(a) begins on the initial gas flow in the well; and

(b) ends on whichever of the following occurs first:

  (i) well shut in; or

  (ii) continuous gas flow from the well to a flow line or a storage vessel for collection.

well workover means the period that:

(a) begins on the initial gas flow in the well that follows remedial operations to increase the well's production; and

(b) ends on whichever of the following occurs first:

  (i) well shut in; or

  (ii) continuous gas flow from the well to a flow line or a storage vessel for collection.

year means a financial year.

Note: The following expressions in this Determination are defined in the Act:

- carbon dioxide equivalence
- consumption of energy (see also regulation 2.26 of the Regulations)
- energy
- facility
- greenhouse gas
- group
- industry sector
- operational control
- potential greenhouse gas emissions
- production of energy (see also regulation 2.25 of the Regulations)
- registered corporation
- scope 1 emission (see also regulation 2.23 of the Regulations)
- scope 2 emission (see also regulation 2.24 of the Regulations).

1.9 Interpretation

(1) In this Determination, a reference to ***emissions*** is a reference to emissions of greenhouse gases.

(2) In this Determination, a reference to a ***gas type (j)*** is a reference to a greenhouse gas.

(3) In this Determination, a reference to a facility that is ***constituted*** by an activity is a reference to the facility being constituted in whole or in part by the activity.

Note: Section 9 of the Act defines a facility as an activity or series of activities.

(4) In this Determination, a reference to a standard, instrument or other writing (other than a Commonwealth Act or Regulations) however described, is a reference to that standard, instrument or other writing as in force on 1 July 2014.

1.9A Meaning of *separate instance of a source*

If 2 or more different activities of a facility have the same source of emissions, each activity is taken to be a separate instance of the source if the activity is performed by a class of equipment different from that used by another activity.

Example: The combustion of liquefied petroleum gas in the engines of distribution vehicles of the facility operator and the combustion of liquid petroleum fuel in lawn mowers at the facility, although the activities have the same source of emissions, are taken to be a separate instance of the source as the activities are different and the class of equipment used to perform the activities are different.

1.9B Meaning of *separate occurrence of a source*

(1) If 2 or more things at a facility have the same source of emissions, each thing may be treated as a separate occurrence of the source.

Example: The combustion of unprocessed natural gas in 2 or more gas flares at a facility may be treated as a separate occurrence of the source (natural gas production or processing—flaring).

(2) If a thing at a facility uses 2 or more energy types, each energy type may be treated as a separate occurrence of the source.

Example: The combustion of diesel and petrol in a vehicle at a facility may be treated as a separate occurrence of the source (fuel combustion).

1.10 Meaning of *source*

(1) A thing mentioned in the column headed 'Source of emissions' of the following table is a ***source***.

Item	Category of source	Source of emissions
1	Fuel combustion	
1A		Fuel combustion
2	Fugitive emissions	
2A		Underground mines
2B		Open cut mines
2C		Decommissioned underground mines
2D		Oil or gas exploration

Item	**Category of source**	**Source of emissions**
2E		Crude oil production
2F		Crude oil transport
2G		Crude oil refining
2H		Natural gas production or processing (other than emissions that are vented or flared)
2I		Natural gas transmission
2J		Natural gas distribution
2K		Natural gas production or processing—flaring
2L		Natural gas production or processing—venting
2M		Carbon capture and storage
3	Industrial processes	
3A		Cement clinker production
3B		Lime production
3C		Use of carbonates for the production of a product other than cement clinker, lime or soda ash
3D		Soda ash use
3E		Soda ash production
3F		Ammonia production
3G		Nitric acid production
3H		Adipic acid production
3I		Carbide production
3J		Chemical or mineral production, other than carbide production, using a carbon reductant or carbon anode
3K		Iron, steel or other metal production using an integrated metalworks
3L		Ferroalloys production
3M		Aluminium production
3N		Other metals production
3O		Emissions of hydrofluorocarbons and sulphur hexafluoride gases
3P		Sodium cyanide production
4	Waste	
4A		Solid waste disposal on land
4AA		Biological treatment of solid waste
4B		Wastewater handling (industrial)
4C		Wastewater handling (domestic or commercial)
4D		Waste incineration

(2) The extent of the source is as provided for in this Determination.

Part 1.2—General

1.11 Purpose of Part

This Part provides for general matters as follows:

(a) Division 1.2.1 provides for the measurement of emissions and energy and also deals with standards;

(b) Division 1.2.2 provides for methods for measuring emissions;

(c) Division 1.2.3 provides requirements in relation to carbon capture and storage.

Division 1.2.1—Measurement and standards

1.12 Measurement of emissions and energy

(1) The measurement of emissions released from the operation of a facility is to be done by estimating the emissions in accordance with this Determination.

(2) The measurement of the production and consumption of energy from the operation of a facility is to be done by estimating the production and consumption of energy in accordance with this Determination.

1.13 General principles for measuring emissions and energy

Estimates for this Determination must be prepared in accordance with the following principles:

(a) transparency—emission and energy estimates must be documented and verifiable;

(b) comparability—emission and energy estimates using a particular method and produced by a registered corporation or registered person in an industry sector must be comparable with emission and energy estimates produced by similar corporations or persons in that industry sector using the same method and consistent with the emission and energy estimates published by the Department in the National Greenhouse Accounts;

(c) accuracy—having regard to the availability of reasonable resources by a registered corporation or registered person and the requirements of this Determination, uncertainties in emission and energy estimates must be minimised and any estimates must neither be over nor under estimates of the true values at a 95% confidence level;

(d) completeness—all identifiable emission sources mentioned in section 1.10 must be accounted for and production and consumption of all identifiable fuels and energy commodities listed in Schedule 1 of the Regulations must be accounted for, subject to any applicable reporting thresholds.

1.14 Assessment of uncertainty

The estimate of emissions released from the operation of a facility must include assessment of uncertainty in accordance with Chapter 8.

1.15 Units of measurement

(1) For this Determination, measurements of fuel must be converted as follows:

(a) for solid fuel, to tonnes; and

(b) for liquid fuels, to kilolitres unless otherwise specified; and

(c) for gaseous fuels, to cubic metres, corrected to standard conditions, unless otherwise specified.

(2) For this Determination, emissions of greenhouses gases must be estimated in CO_2-e tonnes.

(3) Measurements of energy content must be converted to gigajoules.

(4) The *National Measurement Act 1960*, and any instrument made under that Act, must be used for conversions required under this section.

1.16 Rounding of amounts

(1) If:

(a) an amount is worked out under this Determination; and

(b) the number is not a whole number;

then:

(c) the number is to be rounded up to the next whole number if the number at the first decimal place equals or exceeds 5; and

(d) rounded down to the next whole number if the number at the first decimal place is less than 5.

(2) Subsection (1) applies to amounts that are measures of emissions or energy.

1.17 Status of standards

If there is an inconsistency between this Determination and a documentary standard, this Determination prevails to the extent of the inconsistency.

Division 1.2.2—Methods

1.18 Method to be used for a separate occurrence of a source

(1) This section deals with the number of methods that may be used to estimate emissions of a particular greenhouse gas released, in relation to a separate occurrence of a source, from the operation of a facility.

(1A) Subsections (2) and (3) do not apply to a facility if:

(a) the principal activity of the facility is electricity generation (ANZSIC industry classification and code 2611) and the generating unit used to perform the principal activity:

(i) does not have the capacity to generate, in a reporting year, the amount of electricity mentioned in subparagraph 2.3(3)(b)(i); and

(ii) generates, in a reporting year, less than or equal to the amount of electricity mentioned in subparagraph 2.3(3)(b)(ii); or

(b) the principal activity of the facility is electricity generation (ANZSIC industry classification and code 2611) and the generating unit used to perform the principal activity:

(i) does not have the capacity to generate, in a reporting year, the amount of electricity mentioned in subparagraph 2.19(3)(b)(i); and

(ii) generates, in a reporting year, less than or equal to the amount of electricity mentioned in subparagraph 2.19(3)(b)(ii).

(2) Subject to subsection (3) and (3A), one method for the separate occurrence of a source must be used for 4 reporting years unless another higher method is used.

(3) If:

(a) at a particular time, a method is being used to estimate emissions in relation to the separate occurrence of a source; and

(b) either:

(i) in the preceding 4 reporting years before that time, only that method has been used to estimate the emissions from the separate occurrence of the source; or

(ii) a registered corporation or registered person certifies in writing that the method used was found to be non-compliant during an external audit of the separate occurrence of the source;

then a lower method may be used to estimate emissions in relation to the separate occurrence of the source from that time.

(3A) If section 22AA of the Act applies to a person, a lower method may be used to estimate emissions in relation to the source for the purposes of reporting under section 22AA.

(4) In this section, ***reporting year***, in relation to a source from the operation of a facility under the operational control of a registered corporation and entities that are members of the corporation's group, means a year that the registered

corporation is required to provide a report under section 19 of the Act in relation to the facility

(5) ***Higher method***, is:

- (a) a prescribed alternative method; or
- (b) in relation to a method (the ***original method***) being used to estimate emissions in relation to a separate occurrence of a source, a method for the source with a higher number than the number of the original method.

(6) ***Lower method***, is:

- (a) a default method; or
- (b) in relation to a method (the ***original method***) being used to estimate emissions in relation to a separate occurrence of a source, a method for the source with a lower number than the number of the original method.

1.18A Conditions—persons preparing report must use same method

(1) This section applies if a person is required, under section 19, 22A, 22AA, 22E, 22G or 22X of the Act (a ***reporting provision***), to provide a report to the Regulator for a reporting year or part of a reporting year (the ***reporting period***).

(2) For paragraph 10(3)(c) of the Act:

- (a) the person must, before 31 August in the year immediately following the reporting year, notify any other person required, under a reporting provision, to provide a report to the Regulator for the same facility of the method the person will use in the report; and
- (b) each person required to provide a report to the Regulator for the same facility and for the same reporting period must, before 31 October in the year immediately following the reporting year, take all reasonable steps to agree on a method to be used for each report provided to the Regulator for the facility and for the reporting period.

(3) If the persons mentioned in paragraph (2)(b) do not agree on a method before 31 October in the year immediately following the reporting year, each report provided to the Regulator for the facility and for the reporting period must use the method:

- (a) that was used in a report provided to the Regulator for the facility for the previous reporting year (if any); and
- (b) that will, of all the methods used in a report provided to the Regulator for the facility for the previous reporting year, result in a measurement of the largest amount of emissions for the facility for the reporting year.

(4) In this section, a reference to a method is a reference to a method or available alternative method, including the options (if any) included in the method or available alternative method.

Note 1: ***Reporting year*** has the meaning given by the Regulations.

Note 2: An example of available alternative methods is method 2 in section 2.5 and method 2 in section 2.6.

Note 3: An example of options included within a method is paragraphs 3.36(a) and (b), which provide 2 options of ways to measure the size of mine void volume.

Note 4: An example of options included within an available alternative method is the options for identifying the value of the oxidation factor (***OFs***) in subsection 2.5(3).

1.19 Temporary unavailability of method

(1) The procedure set out in this section applies if, during a reporting year, a method for a separate occurrence of a source cannot be used because of a mechanical or technical failure of equipment or a failure of measurement systems during a period (the ***down time***).

(2) For each day or part of a day during the down time, the estimation of emissions from the separate occurrence of a source must be consistent with the principles in section 1.13.

(3) Subsection (2) only applies for a maximum of 6 weeks in a year. This period does not include down time taken for the calibration of the equipment.

(4) If down time is more than 6 weeks in a year, the registered corporation or registered person must inform the Regulator, in writing, of the following:
  (a) the reason why down time is more than 6 weeks;
  (b) how the corporation or person plans to minimise down time;
  (c) how emissions have been estimated during the down time.

(5) The information mentioned in subsection (4) must be given to the Regulator within 6 weeks after the day when down time exceeds 6 weeks in a year.

(6) The Regulator may require a registered corporation or registered person to use method 1 to estimate emissions during the down time if:
  (a) method 2, 3 or 4 has been used to estimate emissions for the separate occurrence of a source; and
  (b) down time is more than 6 weeks in a year.

Division 1.2.3—Requirements in relation to carbon capture and storage

1.19A Meaning of *captured for permanent storage*

For this Determination, a greenhouse gas is ***captured for permanent storage*** only if it is captured by, or transferred to:

(a) the registered holder of a greenhouse gas injection licence under the *Offshore Petroleum and Greenhouse Gas Storage Act 2006* for the purpose of being injected into an identified greenhouse gas storage formation under the licence in accordance with that Act; or

(b) the holder of an injection and monitoring licence under the **Greenhouse Gas Geological Sequestration Act 2008** (Vic) for the purpose of being injected into an underground geological formation under the licence in accordance with that Act; or

(c) the registered holder of a greenhouse gas injection licence under the **Offshore Petroleum and Greenhouse Gas Storage Act 2010** (Vic) for the purpose of being injected into an identified greenhouse gas storage formation under the licence in accordance with that Act; or

(d) the holder of a GHG injection and storage lease under the *Greenhouse Gas Storage Act 2009* (Qld) for the purpose of being injected into a GHG stream storage site under the lease in accordance with that Act; or

(e) the holder of an approval under the *Barrow Island Act 2003* (WA) for the purpose of being injected into an underground reservoir or other subsurface formation in accordance with that Act; or

(f) the holder of a gas storage licence under the *Petroleum and Geothermal Energy Act 2000* (SA) for the purpose of being injected into a natural reservoir under the licence in accordance with that Act.

1.19B Deducting greenhouse gas that is captured for permanent storage

(1) If a provision of this Determination provides that an amount of a greenhouse gas that is captured for permanent storage may be deducted in the estimation of emissions under the provision, then the amount of the greenhouse gas may be deducted only if:

(a) the greenhouse gas that is captured for permanent storage is captured by, or transferred to, a relevant person; and

(b) the amount of the greenhouse gas that is captured for permanent storage is estimated in accordance with section 1.19E; and

(c) the relevant person issues a written certificate that complies with subsection (2).

(2) The certificate must specify:

(a) if the greenhouse gas is captured by the relevant person and is neither transferred to the relevant person nor transferred by the relevant person to another person—the following information:

(i) the amount of the greenhouse gas, measured in CO_2-e tonnes, captured by the relevant person;
(ii) the volume of the greenhouse gas stream containing the captured greenhouse gas;
(iii) the concentration of the greenhouse gas in the stream; or

(b) if the greenhouse gas is transferred to the relevant person—the following information:
(i) the amount of the greenhouse gas, measured in CO_2-e tonnes, that was transferred to the relevant person;
(ii) the volume of the greenhouse gas stream containing the transferred greenhouse gas;
(iii) the concentration of the greenhouse gas in the stream.

(3) The amount of the greenhouse gas that may be deducted is the amount specified in the certificate under paragraph (1)(c).

1.19C Capture from facility with multiple sources jointly generated

If, during the operation of a facility, more than 1 source generates a greenhouse gas, the total amount of the greenhouse gas that may be deducted in relation to the facility is to be attributed:

(a) if it is possible to determine the amount of the greenhouse gas that is captured for permanent storage from each source—to each source from which the greenhouse gas is captured according to the amount captured from the source; or

(b) if it is not possible to determine the amount of the greenhouse gas captured for permanent storage from each source—to the main source that generated the greenhouse gas that is captured during the operation of the facility.

1.19D Capture from a source where multiple fuels consumed

If more than 1 fuel is consumed for a source that generates a greenhouse gas that is captured for permanent storage, the total amount of the greenhouse gas that may be deducted in relation to the source is to be attributed to each fuel consumed in proportion to the carbon content of the fuel relative to the total carbon content of all fuel consumed for that source.

1.19E Measure of quantity of captured greenhouse gas

(1) For paragraph 1.19B(1)(b), the amount of a greenhouse gas that is captured must be estimated in accordance with this section.

(2) The volume of the greenhouse gas stream containing the captured greenhouse gas must be estimated:

(a) if the greenhouse gas stream is transferred to a relevant person—using:
(i) criterion A in section 1.19F; or
(ii) criterion AAA in section 1.19G; or

- (b) if the greenhouse gas stream is captured by the relevant person and is neither transferred to the relevant person nor transferred by the relevant person to another person—using:
    - (i) criterion AAA in section 1.19G; or
    - (ii) criterion BBB in section 1.19GA.

(3) The greenhouse gas stream must be sampled in accordance with ISO 10715:1997, or an equivalent standard.

(4) The concentration of the greenhouse gas in the greenhouse gas stream must be analysed in accordance with the following parts of ISO 6974 or an equivalent standard:
- (a) Part 1 (2000);
- (b) Part 2 (2001);
- (c) Part 3 (2000);
- (d) Part 4 (2000);
- (e) Part 5 (2000);
- (f) Part 6 (2002).

(5) The volume of the greenhouse gas stream must be expressed in cubic metres.

(6) The greenhouse gas stream must be analysed for the concentration of the greenhouse gas on at least a monthly basis.

1.19F Volume of greenhouse gas stream—criterion A

(1) For subparagraph 1.19E(2)(a)(i), criterion A is the volume of the greenhouse gas stream that is:
- (a) transferred to the relevant person during the year; and
- (b) specified in a certificate issued by the relevant person under paragraph 1.19B(1)(c).

(2) The volume specified in the certificate must be accurate and must be evidenced by invoices issued by the relevant person.

1.19G Volume of greenhouse gas stream—criterion AAA

(1) For subparagraphs 1.19E(2)(a)(ii) and (b)(i), criterion AAA is the measurement during the year of the captured greenhouse gas stream from the operation of a facility at the point of capture.

(2) In measuring the quantity of the greenhouse gas stream at the point of capture, the quantity of the greenhouse gas stream must be measured:
- (a) using volumetric measurement in accordance with:
    - (i) for a compressed greenhouse gas stream—section 1.19H; and
    - (ii) for a super-compressed greenhouse gas stream—section 1.19I; and
- (b) using gas measuring equipment that complies with section 1.19J.

(3) The measurement must be carried out using measuring equipment that:

(a) is in a category specified in column 2 of an item in the table in subsection (4) according to the maximum daily quantity of the greenhouse gas stream captured specified in column 3 for that item from the operation of the facility; and

(b) complies with the transmitter and accuracy requirements for that equipment specified in column 4 for that item, if the requirements are applicable to the measuring equipment being used.

(4) For subsection (3), the table is as follows.

Item	Gas measuring equipment category	Maximum daily quantity of greenhouse gas stream (cubic metres/day)	Transmitter and accuracy requirements (% of range)
1	1	0–50 000	Pressure <±0.25% Diff. pressure <±0.25% Temperature <±0.50%
2	2	50 001–100 000	Pressure <±0.25% Diff. pressure <±0.25% Temperature <±0.50%
3	3	100 001–500 000	Smart transmitters: Pressure <±0.10% Diff. pressure <±0.10% Temperature <±0.25%
4	4	500 001 or more	Smart transmitters: Pressure <±0.10% Diff. pressure <±0.10% Temperature <±0.25%

1.19GA Volume of greenhouse gas stream—criterion BBB

For subparagraph 1.19E(2)(b)(ii), criterion BBB is the estimation of the volume of the captured greenhouse gas stream from the operation of the facility during a year measured in accordance with industry practice, if the equipment used to measure the volume of the captured greenhouse gas stream does not meet the requirements of criterion AAA.

Note: An estimate obtained using industry practice must be considered with the principles in section 1.13.

1.19H Volumetric measurement—compressed greenhouse gas stream

(1) For subparagraph 1.19G(2)(a)(i), volumetric measurement of a compressed greenhouse gas stream must be in cubic metres at standard conditions.

(1A) For this section and subparagraph 1.19G(2)(a)(i), a compressed greenhouse gas stream does not include either of the following:

(a) a super-compressed greenhouse gas stream;

(b) a greenhouse gas stream that is compressed to a super-critical state.

(2) The volumetric measurement is to be calculated using a flow computer that measures and analyses flow signals and relative density:

(a) if the greenhouse gas stream is captured by the relevant person and is neither transferred to the relevant person nor transferred by the relevant person to another person—at the point of capture of the greenhouse gas stream; or

(b) if the greenhouse gas stream is transferred to a relevant person—at the point of transfer of the greenhouse gas stream.

(3) The volumetric flow rate must be continuously recorded and integrated using an integration device that is isolated from the flow computer in such a way that if the computer fails, the integration device will retain the last reading, or the previously stored information, that was on the computer immediately before the failure.

(4) Subject to subsection (5), all measurements, calculations and procedures used in determining volume (except for any correction for deviation from the ideal gas law) must be made in accordance with the instructions contained in the following:

(a) for orifice plate measuring systems:

(i) the publication entitled *AGA Report No. 3*, *Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 3: Natural Gas Applications,* published by the American Gas Association in August 1992; or

(ii) Parts 1 to 4 of the publication entitled *ANSI/API MPMS Chapter 14.3 Part 2 (R2011) Natural Gas Fluids Measurement: Concentric, Square-Edged Orifice Meters - Part 2: Specification and Installation Requirements*, 4th edition, published by the American Petroleum Institute on 30 April 2000;

(b) for turbine measuring systems—the publication entitled *AGA Report No. 7, Measurement of Natural Gas by Turbine Meter (2006),* published by the American Gas Association on 1 January 2006;

(c) for positive displacement measuring systems—the publication entitled *ANSI B109.3—2000, Rotary Type Gas Displacement Meters*, published by the American Gas Association on 13 April 2000.

(5) Measurements, calculations and procedures used in determining volume may also be made in accordance with an equivalent internationally recognised documentary standard or code.

(6) Measurements must comply with Australian legal units of measurement.

1.19I Volumetric measurement—super-compressed greenhouse gas stream

(1) For subparagraph 1.19G(2)(a)(ii), volumetric measurement of a super-compressed greenhouse gas stream must be in accordance with this section.

(2) If, in determining volume in relation to the super-compressed greenhouse gas stream, it is necessary to correct for deviation from the ideal gas law, the correction must be determined using the relevant method contained in the publication entitled *AGA Report No. 8, Compressibility Factor of Natural Gas and Related Hydrocarbon Gases (1994)*, published by the American Gas Association on 1 January 1994.

(3) The measuring equipment used must calculate super-compressibility by:

(a) if the measuring equipment is category 3 or 4 equipment in accordance with column 2 the table in subsection 1.19G(4)—using composition data; or

(b) if the measuring equipment is category 1 or 2 equipment in accordance with column 2 of the table in subsection 1.19G(4)—using an alternative method set out in the publication entitled *AGA Report No. 8, Compressibility Factor of Natural Gas and Related Hydrocarbon Gases (1994)*, published by the American Gas Association on 1 January 1994.

1.19J Gas measuring equipment—requirements

For paragraph 1.19G(2)(b), gas measuring equipment that is category 3 or 4 equipment in accordance with column 2 of the table in subsection 1.19G(4) must comply with the following requirements:

(a) if the equipment uses flow devices—the requirements relating to flow devices set out in section 1.19K;

(b) if the equipment uses flow computers—the requirement relating to flow computers set out in section 1.19L;

(c) if the equipment uses gas chromatographs—the requirements relating to gas chromatographs set out in section 1.19M.

1.19K Flow devices—requirements

(1) If the measuring equipment has flow devices that use orifice measuring systems, the flow devices must be constructed in a manner that ensures that the maximum uncertainty of the discharge coefficient is not greater than ±1.5%.

Note: The publication entitled *AGA Report No. 3*, *Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 3: Natural Gas Applications,* published by the American Gas Association in August 1992, sets out a manner that ensures that the maximum uncertainty of the discharge coefficient is not greater than ±1.5%.

(2) If the measuring equipment has flow devices that use turbine measuring systems, the flow devices must be installed in a manner that ensures that the maximum uncertainty of the flow measurement is not greater than ±1.5%.

Note: The publication entitled *AGA Report No. 8, Compressibility Factor of Natural Gas and Related Hydrocarbon Gases (1994),* published by the American Gas Association on 1 January 1994, sets out a manner that ensures that the maximum uncertainty of the flow measurement is not greater than ±1.5%.

(3) If the measuring equipment has flow devices that use positive displacement measuring systems, the flow devices must be installed in a manner that ensures that the maximum uncertainty of flow is ±1.5%.

Note: The publication entitled *ANSI B109.3—2000, Rotary Type Gas Displacement Meters*, published by the American Gas Association on 13 April 2000, sets out a manner for installation that ensures that the maximum uncertainty of flow is ±1.5%.

(4) If the measuring equipment uses any other type of flow device, the maximum uncertainty of flow measurement must not be greater than ±1.5%.

(5) All flow devices that are used by measuring equipment of a category specified in column 2 of the table in subsection 1.19G(4) must, wherever possible, be calibrated for pressure, differential pressure and temperature in accordance with the requirements specified in column 4 for the category of equipment specified in column 2 for that item. The calibrations must take into account the effects of static pressure and ambient temperature.

1.19L Flow computers—requirements

For paragraph 1.19J(b), the requirement is that the flow computer that is used by the equipment for measuring purposes must record the instantaneous values for all primary measurement inputs and must also record the following outputs:

(a) instantaneous corrected volumetric flow;
(b) cumulative corrected volumetric flow;
(c) for turbine and positive displacement metering systems—instantaneous uncorrected volumetric flow;
(d) for turbine and positive displacement metering systems—cumulative uncorrected volumetric flow;
(e) super-compressibility factor.

1.19M Gas chromatographs

For paragraph 1.19J(c), the requirements are that gas chromatographs used by the measuring equipment must:

(a) be factory tested and calibrated using a measurement standard produced by gravimetric methods and traceable to Australian legal units of measurement; and
(b) perform gas composition analysis with an accuracy of ±0.25% for calculation of relative density; and
(c) include a mechanism for re-calibration against a certified reference gas.

Part 1.3—Method 4—Direct measurement of emissions

Division 1.3.1—Preliminary

1.20 Overview

(1) This Chapter provides for method 4 for a source.

Note: Method 4 as provided for in this Part applies to a source as indicated in the Chapter, Part, Division or Subdivision dealing with the source.

(2) Method 4 requires the direct measurement of emissions released from the source from the operation of a facility during a year by monitoring the gas stream at a site within part of the area (for example, a duct or stack) occupied for the operation of the facility.

(3) Method 4 consists of the following:

(a) method 4 (CEM) as specified in section 1.21 that requires the measurement of emissions using continuous emissions monitoring (***CEM***);

(b) method 4 (PEM) as specified in section 1.27 that requires the measurement of emissions using periodic emissions monitoring (***PEM***).

Division 1.3.2—Operation of method 4 (CEM)

Subdivision 1.3.2.1—Method 4 (CEM)

1.21 Method 4 (CEM)—estimation of emissions

(1) To obtain an estimate of the mass of emissions of a gas type (***j***), being methane, carbon dioxide or nitrous oxide, released at the time of measurement at a monitoring site within the area occupied for the operation of a facility, the following formula must be applied:

$$M_{jct} = \frac{MM_j \times P_{ct} \times FR_{ct} \times C_{jct}}{8.314T_{ct}}$$

where:

M_{jct} is the mass of emissions in tonnes of gas type (***j***) released per second.

MM_j is the molecular mass of gas type (***j***) measured in tonnes per kilomole which:

(a) for methane is 16.04×10^{-3}; or
(b) for carbon dioxide is 44.01×10^{-3}; or
(c) for nitrous oxide is 44.01×10^{-3}.

P_{ct} *is* the pressure of the gas stream in kilopascals at the time of measurement.

FR_{ct} is the flow rate of the gas stream in cubic metres per second at the time of measurement.

C_{jct} is the proportion of gas type (***j***) in the volume of the gas stream at the time of measurement.

T_{ct} is the temperature, in degrees kelvin, of the gas at the time of measurement.

(2) The mass of emissions estimated under subsection (1) must be converted into CO_2-e tonnes.

(3) Data on estimates of the mass emissions rates obtained under subsection (1) during an hour must be converted into a representative and unbiased estimate of mass emissions for that hour.

(4) The estimate of emissions of gas type (***j***) during a year is the sum of the estimates for each hour of the year worked out under subsection (3).

(5) If method 1 is available for the source, the total mass of emissions for a gas from the source for the year calculated under this section must be reconciled against an estimate for that gas from the facility for the same period calculated using method 1 for that source.

1.21A Emissions from a source where multiple fuels consumed

If more than one fuel is consumed for a source that generates carbon dioxide that is directly measured using method 4 (CEM), the total amount of carbon dioxide is to be attributed to each fuel consumed in proportion to the carbon content of the fuel relative to the total carbon content of all fuel consumed for that source.

Subdivision 1.3.2.2—Method 4 (CEM)—use of equipment

1.22 Overview

The following apply to the use of equipment for CEM:

(a) the requirements in section 1.23 about location of the sampling positions for the CEM equipment;
(b) the requirements in section 1.24 about measurement of volumetric flow rates in the gas stream;
(c) the requirements in section 1.25 about measurement of the concentrations of greenhouse gas in the gas stream;
(d) the requirements in section 1.26 about frequency of measurement.

1.23 Selection of sampling positions for CEM equipment

For paragraph 1.22(a), the location of sampling positions for the CEM equipment in relation to the gas stream must be selected in accordance with an appropriate standard.

Note: Appropriate standards include:

- AS 4323.1—1995 *Stationary source emissions - Selection of sampling positions*.
- AS 4323[1].1—1995 Amdt 1-1995 *Stationary source emissions - Selection of sampling positions*.
- ISO 10396:2007 *Stationary source emissions - Sampling for the automated determination of gas emission concentrations for permanently-installed monitoring systems*.
- ISO 10012:2003 *Measurement management systems - Requirements for measurement processes and measuring equipment*.
- USEPA – *Method 1 – Sample and Velocity Traverses for Stationary Sources* (2000).

1.24 Measurement of flow rates by CEM

For paragraph 1.22(b), the measurement of the volumetric flow rates by CEM of the gas stream must be undertaken in accordance with an appropriate standard.

Note: Appropriate standards include:

- ISO 10780:1994 *Stationary source emissions—Measurement of velocity and volume flowrate of gas streams in ducts*.
- ISO 14164:1999 *Stationary source emissions—Determination of the volume flowrate of gas streams in ducts - Automated method*.

- USEPA Method 2 *Determination of Stack Gas Velocity and Volumetric flowrate (Type S Pitot tube)* (2000).
- USEPA Method 2A *Direct Measurement of Gas Volume Through Pipes and Small Ducts* (2000).

1.25 Measurement of gas concentrations by CEM

For paragraph 1.22(c), the measurement of the concentrations of gas in the gas stream by CEM must be undertaken in accordance with an appropriate standard.

Note: Appropriate standards include:

- USEPA Method 3A *Determination of oxygen and carbon dioxide concentrations in emissions from stationary sources (instrumental analyzer procedure)* (2006).
- USEPA Method 3C *Determination of carbon dioxide, methane, nitrogen, and oxygen from stationary sources* (1996).
- ISO 12039:2001 *Stationary source emissions—Determination of carbon monoxide, carbon dioxide and oxygen—Performance characteristics and calibration of automated measuring system*.

1.26 Frequency of measurement by CEM

(1) For paragraph 1.22(d), measurements by CEM must be taken frequently enough to produce data that is representative and unbiased.

(2) For subsection (1), if part of the CEM equipment is not operating for a period, readings taken during periods when the equipment was operating may be used to estimate data on a pro rata basis for the period that the equipment was not operating.

(3) Frequency of measurement will also be affected by the nature of the equipment.

Example: If the equipment is designed to measure only one substance, for example, carbon dioxide or methane, measurements might be made every minute. However, if the equipment is designed to measure different substances in alternate time periods, measurements might be made much less frequently, for example, every 15 minutes.

(4) The CEM equipment must operate for more than 90% of the period for which it is used to monitor an emission.

(5) In working out the period during which CEM equipment is being used to monitor for the purposes of subsection (4), exclude downtime taken for the calibration of equipment.

Division 1.3.3—Operation of method 4 (PEM)

Subdivision 1.3.3.1—Method 4 (PEM)

1.27 Method 4 (PEM)—estimation of emissions

(1) To obtain an estimate of the mass emissions rate of methane, carbon dioxide or nitrous oxide released at the time of measurement at a monitoring site within the area occupied for the operation of a facility, the formula in subsection 1.21(1) must be applied.

(2) The mass of emissions estimated under the formula must be converted into CO_2-e tonnes.

(3) The average mass emissions rate for the gas measured in CO_2-e tonnes per hour for a year must be calculated from the estimates obtained under subsection (1).

(4) The total mass of emissions of the gas for the year is calculated by multiplying the average emissions rate obtained under subsection (3) by the number of hours during the year when the site was operating.

(5) If method 1 is available for the source, the total mass of emissions of the gas for a year calculated under this section must be reconciled against an estimate for that gas from the site for the same period calculated using method 1 for that source.

1.27A Emissions from a source where multiple fuels consumed

If more than one fuel is consumed for a source that generates carbon dioxide that is directly measured using method 4 (PEM), the total amount of carbon dioxide is to be attributed to each fuel consumed in proportion to the carbon content of the fuel relative to the total carbon content of all fuel consumed for that source.

1.28 Calculation of emission factors

(1) Data obtained from periodic emissions monitoring of a gas stream may be used to estimate the average emission factor for the gas per unit of fuel consumed or material produced.

(2) In this section, ***data*** means data about:

(a) volumetric flow rates estimated in accordance with section 1.31; or

(b) gas concentrations estimated in accordance with section 1.32; or

(c) consumption of fuel or material input, estimated in accordance with Chapters 2 to 7; or

(d) material produced, estimated in accordance with Chapters 2 to 7.

Subdivision 1.3.3.2—Method 4 (PEM)—use of equipment

1.29 Overview

The following requirements apply to the use of equipment for PEM:

(a) the requirements in section 1.30 about location of the sampling positions for the PEM equipment;

(b) the requirements in section 1.31 about measurement of volumetric flow rates in a gas stream;

(c) the requirements in section 1.32 about measurement of the concentrations of greenhouse gas in the gas stream;

(d) the requirements in section 1.33 about representative data.

1.30 Selection of sampling positions for PEM equipment

For paragraph 1.29(a), the location of sampling positions for PEM equipment must be selected in accordance with an appropriate standard.

Note: Appropriate standards include:

- AS 4323.1—1995 *Stationary source emissions—Selection of sampling positions*.
- AS 4323.1-1995 Amdt 1-1995 *Stationary source emissions—Selection of sampling positions*.
- ISO 10396:2007 *Stationary source emissions—Sampling for the automated determination of gas emission concentrations for permanently-installed monitoring systems*.
- ISO 10012:2003 *Measurement management systems—Requirements for measurement processes and measuring equipment*.
- USEPA Method 1 *Sample and Velocity Traverses for Stationary Sources* (2000).

1.31 Measurement of flow rates by PEM equipment

For paragraph 1.29(b), the measurement of the volumetric flow rates by PEM of the gas stream must be undertaken in accordance with an appropriate standard.

Note: Appropriate standards include:

- ISO 10780:1994 *Stationary source emissions – Measurement of velocity and volume flowrate of gas streams in ducts*.
- ISO 14164:1999 *Stationary source emissions. Determination of the volume flow rate of gas streams in ducts – automated method*.
- USEPA Method 2 *Determination of stack velocity and volumetric flow rate (Type S Pitot tube) (2000)*.
- USEPA Method 2A *Direct measurement of gas volume through pipes and small ducts (2000)*.

1.32 Measurement of gas concentrations by PEM

For paragraph 1.29(c), the measurement of the concentrations of greenhouse gas in the gas stream by PEM must be undertaken in accordance with an appropriate standard.

Note: Appropriate standards include:

- USEPA Method 3A *Determination of oxygen and carbon dioxide concentrations in emissions from stationary sources (instrumental analyser procedure)* (2006).
- USEPA Method 3C *Determination of carbon dioxide, methane, nitrogen, and oxygen from stationary sources* (1996).
- ISO12039:2001 *Stationary source emissions – Determination of carbon monoxide, carbon dioxide and oxygen – Performance characteristics and calibration of an automated measuring method*.

1.33 Representative data for PEM

(1) For paragraph 1.29(d), sampling by PEM must be undertaken during the year for a sufficient duration to produce representative data that may be reliably extrapolated to provide estimates of emissions across the full range of operating conditions for that year.

(2) Emission estimates using PEM equipment must also be consistent with the principles in section 1.13.

Division 1.3.4—Performance characteristics of equipment

1.34 Performance characteristics of CEM or PEM equipment

(1) The performance characteristics of CEM or PEM equipment must be measured in accordance with this section.

(2) The test procedure specified in an appropriate standard must be used for measuring the performance characteristics of CEM or PEM equipment.

(3) For the calibration of CEM or PEM equipment, the test procedure must be:
  (a) undertaken by an accredited laboratory; or
  (b) undertaken by a laboratory that meets requirements equivalent to ISO 17025; or
  (c) undertaken in accordance with applicable State or Territory legislation.

(4) As a minimum requirement, a cylinder of calibration gas must be certified by an accredited laboratory accredited to ISO Guide 34:2000 as being within 2% of the concentration specified on the cylinder label.

Chapter 2—Fuel combustion

Part 2.1—Preliminary

2.1 Outline of Chapter

This Chapter provides for the following matters:

(a) emissions released from the following sources:
  (i) the combustion of solid fuels (see Part 2.2);
  (ii) the combustion of gaseous fuels (Part 2.3);
  (iii) the combustion of liquid fuels (Part 2.4);
  (iv) fuel use by certain industries (Part 2.5);
(b) the measurement of fuels in blended fuels (Part 2.6);
(c) the estimation of energy for certain purposes (Part 2.7).

Part 2.2—Emissions released from the combustion of solid fuels

Division 2.2.1—Preliminary

2.2 Application

This Part applies to emissions released from the combustion of solid fuel in relation to a separate instance of a source if the amount of solid fuel combusted in relation to the separate instance of the source is more than 1 tonne.

2.3 Available methods for estimating emissions of carbon dioxide, methane and nitrous oxide

(1) Subject to section 1.18, for estimating emissions released from the combustion of a solid fuel consumed from the operation of a facility during a year:
  (a) one of the following methods must be used for estimating emissions of carbon dioxide:
    (i) subject to subsection (3), method 1 under section 2.4;
    (ii) method 2 using an oxidation factor under section 2.5 or an estimated oxidation factor under section 2.6;
    (iii) method 3 using an oxidation factor or an estimated oxidation factor under section 2.12;
    (iv) method 4 under Part 1.3; and
  (b) method 1 under section 2.4 must be used for estimating emissions of methane and nitrous oxide.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

(3) Method 1 must not be used for estimating emissions of carbon dioxide for the main fuel combusted from the operation of the facility if:
  (a) the principal activity of the facility is electricity generation (ANZSIC industry classification and code 2611); and
  (b) the generating unit:
    (i) has the capacity to produce 30 megawatts or more of electricity; and
    (ii) generates more than 50 000 megawatt hours of electricity in a reporting year.

Note: There is no method 2, 3 or 4 for paragraph (1)(b).

Division 2.2.2—Method 1—emissions of carbon dioxide, methane and nitrous oxide from solid fuels

2.4 Method 1—solid fuels

For subparagraph 2.3(1)(a)(i), method 1 is:

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

where:

E_{ij} is the emissions of gas type (***j***), being carbon dioxide, methane or nitrous oxide, released from the combustion of fuel type (***i***) from the operation of the facility during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type ***(i)*** measured in tonnes and estimated under Division 2.2.5.

EC_i is the energy content factor of fuel type ***(i)*** estimated under section 6.5.

EF_{ijoxec} is the emission factor for each gas type (***j***) (which includes the effect of an oxidation factor) released from the combustion of fuel type (***i***) measured in kilograms of CO_2-e per gigajoule according to source as mentioned in Schedule 1.

Division 2.2.3—Method 2—emissions from solid fuels

Subdivision 2.2.3.1—Method 2—estimating carbon dioxide using default oxidation factor

2.5 Method 2—estimating carbon dioxide using oxidation factor

(1) For subparagraph 2.3(1)(a)(ii), method 2 is:

$$E_{ico_2} = \frac{Q_i \times EC_i \times EF_{ico_2oxec}}{1\ 000} - \gamma RCCS_{co_2}$$

where:

$\boldsymbol{E_{ico_2}}$ means the emissions of carbon dioxide released from the combustion of fuel type (***i***) from the operation of the facility during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of fuel type (***i***) measured in tonnes and estimated under Division 2.2.5.

$\boldsymbol{EC_i}$ is the energy content factor of fuel type ***(i)*** estimated under section 6.5.

$\boldsymbol{EF_{ico_2oxec}}$ is the carbon dioxide emission factor for fuel type (***i***) measured in kilograms of CO_2-e per gigajoule as worked out under subsection (2).

$\boldsymbol{\gamma}$ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$\boldsymbol{RCCS_{CO_2}}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

(2) For $\boldsymbol{EF_{ico_2oxec}}$ in subsection (1), estimate as follows:

$$EF_{ico_2oxec} = \frac{EF_{ico_2ox,kg}}{EC_i} \times 1\ 000$$

where:

$\boldsymbol{EF_{ico_2ox,kg}}$ is the carbon dioxide emission factor for fuel type (***i***) measured in kilograms of CO_2-e per kilogram of fuel as worked out under subsection (3).

$\boldsymbol{EC_i}$ is the energy content factor of fuel type (***i***) as obtained under subsection (1).

(3) For $\boldsymbol{EF_{ico_2ox,kg}}$ in subsection (2), work out as follows:

$$EF_{ico_2ox,kg} = \frac{C_{ar}}{100} \times OF_s \times 3.664$$

where:

C_{ar} is the percentage of carbon in fuel type (***i***), as received for the facility or as combusted from the operation of the facility, worked out under subsection (4).

OF_s, or oxidation factor, is 1.0.

(4) For C_{ar} in subsection (3), work out as follows:

$$C_{ar} = \frac{C_{daf} \times (100 - M_{ar} - A_{ar})}{100}$$

where:

C_{daf} is the amount of carbon in fuel type (***i***) as a percentage of the dry ash-free mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

M_{ar} is the amount of moisture in fuel type (***i***) as a percentage of the as received or as combusted mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

A_{ar} is the amount of ash in fuel type (***i***) as a percentage of the as received or as combusted mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

Subdivision 2.2.3.2—Method 2—estimating carbon dioxide using an estimated oxidation factor

2.6 Method 2—estimating carbon dioxide using an estimated oxidation factor

(1) For subparagraph 2.3(1)(a)(ii), method 2 is:

$$E_{ico_2} = \frac{Q_i \times EC_i \times EF_{ico_2oxec}}{1\,000} - \gamma RCCS_{co_2}$$

where:

E_{ico_2} means the emissions of carbon dioxide released from the combustion of fuel type (***i***) from the operation of the facility during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type (***i***) measured in tonnes and estimated under Division 2.2.5.

EC_i is the energy content factor of fuel type ***(i)*** estimated under section 6.5.

EF_{ico_2oxec} is the amount worked out under subsection (2).

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

(2) For EF_{ico_2oxec} in subsection (1), work out as follows:

$$EF_{ico_2oxec} = \frac{EF_{ico_2ox,kg}}{EC_i} \times 1\,000$$

where:

$EF_{ico_2ox,kg}$ is the carbon dioxide emission factor for the type of fuel measured in kilograms of CO_2-e per kilogram of the type of fuel as worked out under subsection (3).

EC_i is the energy content factor of fuel type (***i***) as obtained under subsection (1).

(3) For $EF_{ico_2ox,kg}$ in subsection (2), estimate as follows:

$$EF_{ico_2ox,kg} = \left(\frac{C_{ar}}{100} - \frac{C_a \times A_{ar}}{\left(100 - C_a\right) \times 100}\right) \times 3.664$$

where:

C_{ar} is the percentage of carbon in fuel type (***i***), as received for the facility or as combusted from the operation of the facility, worked out under subsection (4).

C_a is the amount of carbon in the ash estimated as a percentage of the as-sampled mass that is the weighted average of fly ash and ash by sampling and analysis in accordance with Subdivision 2.2.3.3.

A_{ar} is the amount of ash in fuel type (***i***) as a percentage of the as received or as combusted mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

(4) For C_{ar}, in subsection (3), estimate as follows:

$$C_{ar} = \frac{C_{daf} \times \left(100 - M_{ar} - A_{ar}\right)}{100}$$

where:

C_{daf} is the amount of carbon in fuel type (***i***) as a percentage of the dry ash-free mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

M_{ar} is the amount of moisture in fuel type (***i***) as a percentage of the as received or as combusted mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

A_{ar} is the amount of ash in fuel type (***i***) as a percentage of the as received or as combusted mass of the fuel estimated using the sampling and analysis provided for in Subdivision 2.2.3.3.

Subdivision 2.2.3.3—Sampling and analysis for method 2 under sections 2.5 and 2.6

2.7 General requirements for sampling solid fuels

(1) A sample of the solid fuel must be derived from a composite of amounts of the solid fuel combusted.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard (if any).

Note: An appropriate standard for most solid mineral fuels is AS 4264.4—1996 *Coal and coke—Sampling—Determination of precision and bias.*

(5) The value obtained from the sample must only be used for the delivery period or consignment of the fuel for which it was intended to be representative.

2.8 General requirements for analysis of solid fuels

(1) A standard for analysis of a parameter of a solid fuel, and the minimum frequency of analysis of a solid fuel, is as set out in Schedule 2.

(2) A parameter of a solid fuel may also be analysed in accordance with a standard that is equivalent to a standard set out in Schedule 2.

(3) Analysis must be undertaken by an accredited laboratory that meets the requirements equivalent to those in AS ISO/IEC 17025:2005. However, analysis may be undertaken by an on-line analyser if:

(a) the analyser is calibrated in accordance with an appropriate standard; and

(b) analysis undertaken to meet the standard is done by a laboratory that meets the requirements equivalent to those in AS ISO/IEC 17025:2005.

Note: An appropriate standard is AS 1038.24—1998, *Coal and coke—Analysis and testing*, Part 24: *Guide to the evaluation of measurements made by on-line coal analysers*.

(4) If a delivery of fuel lasts for a month or less, analysis must be conducted on a delivery basis.

(5) However, if the properties of the fuel do not change significantly between deliveries over a period of a month, analysis may be conducted on a monthly basis.

(6) If a delivery of fuel lasts for more than a month, and the properties of the fuel do not change significantly before the next delivery, analysis of the fuel may be conducted on a delivery basis rather than monthly basis.

2.9 Requirements for analysis of furnace ash and fly ash

For furnace ash and fly ash, analysis of the carbon content must be undertaken in accordance with AS 3583.2—1991 *Determination of moisture content* and AS 3583.3—1991 *Determination of loss on ignition* or a standard that is equivalent to those standards.

2.10 Requirements for sampling for carbon in furnace ash

(1) This section applies to furnace ash sampled for its carbon content if the ash is produced from the operation of a facility that is constituted by a plant.

(2) A sample of the ash must be derived from representative operating conditions in the plant.

(3) A sample of ash may be collected:
  (a) if contained in a wet extraction system—by using sampling ladles to collect it from sluiceways; or
  (b) if contained in a dry extraction system—directly from the conveyer; or
  (c) if it is not feasible to use one of the collection methods mentioned in paragraph (a) or (b)—by using another collection method that provides representative ash sampling.

2.11 Sampling for carbon in fly ash

Fly ash must be sampled for its carbon content in accordance with:
  (a) a procedure set out in column 2 of an item in the following table, and at a frequency set out in column 3 for that item; or
  (b) if it is not feasible to use one of the procedures mentioned in paragraph (a)—another procedure that provides representative ash sampling, at least every two years, or after significant changes in operating conditions.

Item	Procedure	Frequency
1	At the outlet of a boiler air heater or the inlet to a flue gas cleaning plant using the isokinetic sampling method in AS 4323.1—1995 or AS 4323.2—1995, or in a standard that is equivalent to one of those standards	At least every 2 years, or after significant changes in operating conditions
2	By using standard industry ‘cegrit’ extraction equipment	At least every year, or after significant changes in operating conditions
3	By collecting fly ash from: (a) the fly ash collection hoppers of a flue gas cleaning plant; or (b) downstream of fly ash collection hoppers from ash silos or sluiceways	At least once a year, or after significant changes in operating conditions

Item	Procedure	Frequency
4	From on-line carbon in ash analysers using sample extraction probes and infrared analysers	At least every 2 years, or after significant changes in operating conditions

Division 2.2.4—Method 3—Solid fuels

2.12 Method 3—solid fuels using oxidation factor or an estimated oxidation factor

(1) For subparagraph 2.3(1)(a)(iii) and subject to this section, method 3 is the same as method 2 whether using the oxidation factor under section 2.5 or using an estimated oxidation factor under section 2.6.

(2) In applying method 2 as mentioned in subsection (1), solid fuels must be sampled in accordance with the appropriate standard mentioned in the table in subsection (3).

(3) A standard for sampling a solid fuel mentioned in column 2 of an item in the following table is as set out in column 3 for that item:

Item	**Fuel**	**Standard**
1	Bituminous coal	AS 4264.1—2009
1A	Sub-bituminous coal	AS 4264.1—2009
1B	Anthracite	AS 4264.1—2009
2	Brown coal	AS 4264.3—1996
3	Coking coal (metallurgical coal)	AS 4264.1—2009
4	Coal briquettes	AS 4264.3—1996
5	Coal coke	AS 4264.2—1996
6	Coal tar	
7	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	CEN/TS 14778 – 1:2006 CEN/TS 15442:2006
8	Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	CEN/TS 14778 – 1:2005 CEN/TS 15442:2006
9	Dry wood	CEN/TS 14778 – 1:2005 CEN/TS 15442:2006
10	Green and air dried wood	CEN/TS 14778 – 1:2005 CEN/TS 15442:2006
11	Sulphite lyes	CEN/TS 14778 – 1:2005 CEN/TS 15442:2006
12	Bagasse	CEN/TS 14778 – 1:2005 CEN/TS 15442:2006
13	Primary solid biomass other than items 9 to 12 and 14 to 15	CEN/TS 14778 – 1:2005 CEN/TS 15442:2006
14	Charcoal	CEN/TS 14778 – 1:2005 CEN/TS 15442:2006

Item	Fuel	Standard
15	Biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	CEN/TS 14778 – 1:2005 CEN/TS 15442:2006

(4) A solid fuel may also be sampled in accordance with a standard that is equivalent to a standard set out in the table in subsection (3).

Note: The analysis is carried out in accordance with the same requirements as for method 2.

Division 2.2.5—Measurement of consumption of solid fuels

2.13 Purpose of Division

This Division sets out how quantities of solid fuels combusted from the operation of a facility are to be estimated for the purpose of working out the-emissions released from the combustion of that fuel.

2.14 Criteria for measurement

(1) For the purpose of calculating the amount of solid fuel combusted from the operation of a facility during a year and, in particular, for $\boldsymbol{Q_i}$ in sections 2.4, 2.5 and 2.6, the quantity of combustion must be estimated in accordance with this section.

Acquisition involves commercial transaction

(2) If the acquisition of the solid fuel involves a commercial transaction, the quantity of fuel combusted must be estimated using one of the following criteria:
  (a) the amount of the solid fuel delivered for the facility during the year as evidenced by invoices issued by the vendor of the fuel (***criterion A***);
  (b) as provided in section 2.15 (***criterion AA***);
  (c) as provided in section 2.16 (***criterion AAA***).

(3) If, during a year, criterion AA, or criterion AAA using paragraph 2.16(2)(a), is used to estimate the quantity of fuel combusted, then, in each year following that year, only criterion AA, or criterion AAA using paragraph 2.16(2)(a), (respectively) is to be used.

Acquisition does not involve commercial transaction

(4) If the acquisition of the solid fuel does not involve a commercial transaction, the quantity of fuel combusted must be estimated using one of the following criteria:
  (a) as provided in paragraph 2.16(2)(a) (***criterion AAA***);
  (b) as provided in section 2.17 (***criterion BBB***).

2.15 Indirect measurement at point of consumption—criterion AA

(1) For paragraph 2.14(2)(b), criterion AA is the amount of the solid fuel combusted from the operation of the facility during a year based on amounts delivered for the facility during the year as adjusted for the estimated change in the quantity of the stockpile of the fuel for the facility during the year.

(2) To work out the adjustment for the estimated change in the quantity of the stockpile of the fuel for the facility during the year, one of the following approaches must be used:
  (a) the survey approach mentioned in subsection (2C);
  (b) the error allowance approach mentioned in subsection (2D).

(2A) The approach selected must be consistent with the principles mentioned in section 1.13.

(2B) The same approach, once selected, must be used for the facility for each year unless:

(a) there has been a material change in the management of the stockpile during the year; and

(b) the change in the management of the stockpile results in the approach selected being less accurate than the alternative approach.

(2C) The survey approach is as follows:

Step 1. Estimate the quantity of solid fuel in the stockpile by:

(a) working out the volume of the solid fuel in the stockpile using aerial or general survey in accordance with industry practice; and

(b) measuring the bulk density of the stockpile in accordance with subregulation (3).

Step 2. Replace the current book quantity with the quantity estimated under step 1.

Step 3. Maintain the book quantity replaced under step 2 by:

(a) adding deliveries made during the year, using:

(i) invoices received for solid fuel delivered to the facility; or

(ii) solid fuel sampling and measurements provided by measuring equipment calibrated to a measurement requirement; and

(b) deducting from the amount calculated under paragraph (a), solid fuel consumed by the facility.

Step 4. Use the book quantity maintained under step 3 to estimate the change in the quantity of the stockpile of the fuel.

(2D) The error allowance approach is as follows:

Step 1. Estimate the quantity of the stockpile by:

(a) working out the volume of the solid fuel in the stockpile using aerial or general survey in accordance with industry practice; and

(b) measuring the bulk density of the stockpile in accordance with subregulation (3).

Step 2. Estimate an error tolerance for the quantity of solid fuel in the stockpile. The error tolerance is an estimate of the uncertainty of the quantity of solid fuel in the stockpile and must be:

(a) based on stockpile management practices at the facility and the uncertainty associated with the energy content and proportion of carbon in the solid fuel; and

(b) consistent with the general principles in section 1.13; and

(c) not more than 6% of the estimated value of the solid fuel in the stockpile worked out under step 1.

Step 3. Work out the percentage difference between the current book quantity and the quantity of solid fuel in the stockpile estimated under step 1.

Step 4. If the percentage difference worked out under step 3 is within the error tolerance worked out under step 2, use the book quantity to estimate the change in the quantity of the stockpile of the fuel.

Step 5. If the percentage difference worked out in step 3 is more than the error tolerance worked out in step 2:

(a) adjust the book quantity by the difference between the percentage worked out under step 3 and the error tolerance worked out under step 2; and

(b) use the book quantity adjusted under paragraph (a) to estimate the change in the quantity of the stockpile of the fuel.

(3) The bulk density of the stockpile must be measured in accordance with:
(a) the procedure in ASTM D/6347/D 6347M-99; or
(b) the following procedure:

Step 1 If the mass of the stockpile:

(a) does not exceed 10% of the annual solid fuel combustion from the operation of a facility—extract a sample from the stockpile using a mechanical auger in accordance with ASTM D 4916-89; or

(b) exceeds 10% of the annual solid fuel combustion — extract a sample from the stockpile by coring.

Step 2 Weigh the mass of the sample extracted.

Step 3 Measure the volume of the hole from which the sample has been extracted.

Step 4 Divide the mass obtained in step 2 by the volume measured in step 3.

(4) Quantities of solid fuel delivered for the facility must be evidenced by invoices issued by the vendor of the fuel.

(5) In this section:

book quantity means the quantity recorded and maintained by the facility operator as the quantity of solid fuel in the stockpile.

2.16 Direct measurement at point of consumption—criterion AAA

(1) For paragraph 2.14(2)(c), criterion AAA is the measurement during a year of the solid fuel combusted from the operation of the facility.

(2) The measurement must be carried out either:
  (a) at the point of combustion using measuring equipment calibrated to a measurement requirement; or
  (b) at the point of sale using measuring equipment calibrated to a measurement requirement.

(3) Paragraph (2)(b) only applies if:
  (a) the change in the stockpile of the fuel for the facility for the year is less than 1% of total combustion on average for the facility during the year; and
  (b) the stockpile of the fuel for the facility at the beginning of the year is less than 5% of total combustion for the year.

2.17 Simplified consumption measurements—criterion BBB

For paragraph 2.14(d), criterion BBB is the estimation of the solid fuel combusted during a year from the operation of the facility in accordance with industry practice if the equipment used to measure combustion of the fuel is not calibrated to a measurement requirement.

Note: An estimate obtained using industry practice must be consistent with the principles in section 1.13.

Part 2.3—Emissions released from the combustion of gaseous fuels

Division 2.3.1—Preliminary

2.18 Application

This Part applies to emissions released from the combustion of gaseous fuels in relation to a separate instance of a source if the amount of gaseous fuel combusted in relation to the separate instance of the source is more than 1000 cubic metres.

2.19 Available methods

(1) Subject to section 1.18, for estimating emissions released from the combustion of a gaseous fuel consumed from the operation of a facility during a year:
  (a) one of the following methods must be used for estimating emissions of carbon dioxide:
    (i) method 1 under section 2.20;
    (ii) method 2 under section 2.21;
    (iii) method 3 under section 2.26;
    (iv) method 4 under Part 1.3; and
  (b) one of the following methods must be used for estimating emissions of methane:
    (i) method 1 under section 2.20;
    (ii) method 2 under section 2.27; and
  (c) method 1 under section 2.20 must be used for estimating emissions of nitrous oxide.

Note: The combustion of gaseous fuels releases emissions of carbon dioxide, methane and nitrous oxide. Method 1 is used to estimate emissions of each of these gases. There is no method 3 or 4 for emissions of methane and no method 2, 3 or 4 for emissions of nitrous oxide.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

(3) Method 1 must not be used for estimating emissions of carbon dioxide for the main fuel combusted from the operation of the facility if:
  (a) the principal activity of the facility is electricity generation (ANZSIC industry classification and code 2611); and
  (b) the generating unit:
    (i) has the capacity to produce 30 megawatts or more of electricity; and
    (ii) generates more than 50 000 megawatt hours of electricity in a reporting year.

Division 2.3.2—Method 1—emissions of carbon dioxide, methane and nitrous oxide

2.20 Method 1—emissions of carbon dioxide, methane and nitrous oxide

(1) For subparagraphs 2.19(1)(a)(i) and (b)(i) and paragraph 2.19(1)(c), method 1 for estimating emissions of carbon dioxide, methane and nitrous oxide is:

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

where:

E_{ij} is the emissions of gas type (***j***), being carbon dioxide, methane or nitrous oxide, from each gaseous fuel type (***i***) released from the operation of the facility during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type (***i***) combusted, whether for stationary energy purposes or transport energy purposes, from the operation of the facility during the year measured in cubic metres or gigajoules and estimated under Division 2.3.6.

EC_i is the energy content factor of fuel type ***(i)*** estimated under section 6.5.

EF_{ijoxec} is the emission factor for each gas type (***j***) released during the year (which includes the effect of an oxidation factor) measured in kilograms CO_2-e per gigajoule of fuel type (***i***) according to source as mentioned in:

(a) for stationary energy purposes—Part 2 of Schedule 1; and
(b) for transport energy purposes—Division 4.1 of Schedule 1.

Note: The combustion of gaseous fuels releases emissions of carbon dioxide, methane and nitrous oxide.

(2) In this section:

stationary energy purposes means purposes for which fuel is combusted that do not involve transport energy purposes.

transport energy purposes includes purposes for which fuel is combusted that consist of any of the following:

(a) transport by vehicles registered for road use;
(b) rail transport;
(c) marine navigation;
(d) air transport.

Note: The combustion of gaseous fuels releases emissions of carbon dioxide, methane and nitrous oxide.

Division 2.3.3—Method 2—emissions of carbon dioxide from the combustion of gaseous fuels

Subdivision 2.3.3.1—Method 2—emissions of carbon dioxide from the combustion of gaseous fuels

2.21 Method 2—emissions of carbon dioxide from the combustion of gaseous fuels

(1) For subparagraph 2.19(1)(a)(ii), method 2 for estimating emissions of carbon dioxide is:

$$E_{ico_2} = \frac{Q_i \times EC_i \times EF_{ico_2oxec}}{1\,000} - \gamma RCCS_{co_2}$$

where:

E_{iCO_2} is emissions of carbon dioxide released from fuel type (***i***) combusted from the operation of the facility during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type (***i***) combusted from the operation of the facility during the year measured in cubic metres or gigajoules and estimated under Division 2.3.6.

EC_i is the energy content factor of fuel type ***(i)*** estimated under section 6.5.

EF_{iCO_2oxec} is the carbon dioxide emission factor for fuel type (***i***) measured in kilograms CO_2-e per gigajoule and calculated in accordance with section 2.22.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

2.22 Calculation of emission factors from combustion of gaseous fuel

(1) For section 2.21, the emission factor **EF_{iCO_2oxec}** from the combustion of fuel type (***i***) must be calculated from information on the composition of each component gas type (***y***) and must first estimate **$EF_{i,CO_2,ox,kg}$** in accordance with the following formula:

$$EF_{i,\,CO2,ox,kg} = \Sigma_y \left[\left(\frac{mol_y\% \times \left(\frac{mw_y}{V}\right) \times 100}{d_{y,\,total}} \right) \times \left(\frac{44.010 \times f_y \times OF_g}{(mw_y \times 100)} \right) \right]$$

where:

$EF_{i,CO2,ox,kg}$ is the carbon dioxide emission factor for fuel type (***i***), incorporating the effects of a default oxidation factor expressed as kilograms of carbon dioxide per kilogram of fuel.

$mol_y\%$, for each component gas type (***y***), is that gas type's share of 1 mole of fuel type (***i***), or that gas type's share of the total volume of fuel type (***i***), expressed as a percentage.

mw_y, for each component gas type (***y***), is the molecular weight of the component gas type (***y***) measured in kilograms per kilomole.

V is the volume of 1 kilomole of the gas at standard conditions and equal to 23.6444 cubic metres.

$d_{y,\ total}$ is as set out in subsection (2).

f_y for each component gas type (***y***), is the number of carbon atoms in a molecule of the component gas type (***y***).

OF_g is the oxidation factor 1.0 applicable to gaseous fuels.

(2) For subsection (1), the factor $d_{y,\ total}$ is worked out using the following formula:

$$d_{y,\ total} = \Sigma_y\ mol_y\% \times \left(\frac{mw_y}{V}\right)$$

where:

$mol_y\%$, for each component gas type (***y***), is that gas type's share of 1 mole of fuel type (***i***), or that gas type's share of the total volume of fuel type (***i***), expressed as a percentage.

mw_y, for each component gas type (***y***), is the molecular weight of the component gas type (***y***) measured in kilograms per kilomole.

(3) For subsection (1), the molecular weight and number of carbon atoms in a molecule of each component gas type (***y***) mentioned in column 2 of an item in the following table is as set out in columns 3 and 4, respectively, for the item:

Item	Component gas y	Molecular Wt (kg/kmole)	Number of carbon atoms in component molecules
1	Methane	16.043	1
2	Ethane	30.070	2
3	Propane	44.097	3
4	Butane	58.123	4
5	Pentane	72.150	5
6	Carbon monoxide	28.016	1
7	Hydrogen	2.016	0

Item	Component gas y	Molecular Wt (kg/kmole)	Number of carbon atoms in component molecules
8	Hydrogen sulphide	34.082	0
9	Oxygen	31.999	0
10	Water	18.015	0
11	Nitrogen	28.013	0
12	Argon	39.948	0
13	Carbon dioxide	44.010	1

(4) The carbon dioxide emission factor EF_{iCO_2oxec} derived from the calculation in subsection (1) must be expressed in terms of kilograms of carbon dioxide per gigajoule calculated using the following formula:

$$EF_{i\,CO_2oxec} = EF_{i\,,CO_2ox,kg} \div \left(\frac{EC_i}{C_i}\right)$$

where:

EC**$_i$* is the energy content factor of fuel type ***(i), measured in gigajoules per cubic metre that is:

(a) mentioned in column 3 of Part 2 of Schedule 1; or

(b) estimated by analysis under Subdivision 2.3.3.2.

C**$_i$* is the density of fuel type (i***) expressed in kilograms of fuel per cubic metre as obtained under subsection 2.24(4).

Subdivision 2.3.3.2—Sampling and analysis

2.23 General requirements for sampling under method 2

(1) A sample of the gaseous fuel must be derived from a composite of amounts of the gaseous fuel combusted.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard (if any).

(5) The value obtained from the samples must only be used for the delivery period, usage period or consignment of the gaseous fuel for which it was intended to be representative.

2.24 Standards for analysing samples of gaseous fuels

(1) Samples of gaseous fuels of a type mentioned in column 2 of an item in the following table must be analysed in accordance with one of the standards mentioned in:

(a) for analysis of energy content—column 3 for that item; and

(b) for analysis of gas composition—column 4 for that item.

Item	Fuel type	Energy content	Gas Composition
1	Natural gas if distributed in a pipeline	ASTM D 1826—94 (2003) ASTM D 7164—05 ASTM 3588—98 (2003) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172—96	ASTM D 1945—03 ASTM D 1946—90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00
2	Coal seam methane that is captured for combustion	ASTM D 1826—94 (2003) ASTM D 7164—05 ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172—96	ASTM D 1945—03 ASTM D 1946—90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00
3	Coal mine waste gas that is captured for combustion	ASTM D 1826 – 94 (2003) ASTM D 7164 – 05 ASTM 3588—98 (2003) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000)	ASTM D 1945 – 03 ASTM D 1946 – 90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000)

Item	Fuel type	Energy content	Gas Composition
		part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172—96	part 6 (2002) GPA 2145 – 03 GPA 2261 – 00
4	Compressed natural gas	ASTM 3588—98 (2003)	N/A
5	Unprocessed natural gas	ASTM D 1826—94 (2003) ASTM D 7164—05 ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172—96	ASTM D 1945—03 ASTM D 1946—90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00
6	Ethane	ASTM D 3588 – 98 (2003) IS0 6976:1995	ASTM D 1945 – 03 ASTM D 1946 – 90 (2006)
7	Coke oven gas	ASTM D 3588—98 (2003) ISO 6976:1995	ASTM D 1945—03 ASTM D 1946—90 (2006)
8	Blast furnace gas	ASTM D 3588—98 (2003) ISO 6976:1995	ASTM D 1945—03 ASTM D 1946—90 (2006)
9	Town gas	ASTM D 1826—94 (2003) ASTM D 7164—05 ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172—96	ASTM D 1945—03 ASTM D 1946—90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00
10	Liquefied natural	ISO 6976:1995	ASTM D 1945 – 03

Item	Fuel type	Energy content	Gas Composition
	gas		ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002)
11	Landfill biogas that is captured for combustion	ASTM D 1826—94 (2003) ASTM D 7164—05 ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172—96	ASTM D 1945—03 ASTM D 1946—90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00
12	Sludge biogas that is captured for combustion	ASTM D 1826 – 94 (2003) ASTM D 7164 – 05 ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) ISO 6976:1995 GPA 2172—96	ASTM D 1945 – 03 ASTM D 1946 – 90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002) GPA 2145 – 03 GPA 2261 – 00
13	A biogas that is captured for combustion, other than those mentioned in items 11 and 12	ASTM D 1826—94 (2003) ASTM D 7164—05 ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000)	ASTM D 1945—03 ASTM D 1946—90 (2006) ISO 6974 part 1 (2000) part 2 (2001) part 3 (2000) part 4 (2000) part 5 (2000) part 6 (2002)

Item	Fuel type	Energy content	Gas Composition
		part 6 (2002)	GPA 2145 – 03
		ISO 6976:1995	GPA 2261 – 00
		GPA 2172—96	

(2) A gaseous fuel mentioned in column 2 of an item in the table in subsection (1) may also be analysed in accordance with a standard that is equivalent to a standard set out in column 3 and 4 of the item.

(3) The analysis must be undertaken:
- (a) by an accredited laboratory; or
- (b) by a laboratory that meets requirements that are equivalent to the requirements in AS ISO/IEC 17025:2005; or
- (c) using an online analyser if:
  - (i) the online analyser is calibrated in accordance with an appropriate standard; and
  - (ii) the online analysis is undertaken in accordance with this section.

Note: An example of an appropriate standard is ISO 6975:1997—*Natural gas—Extended analysis—Gas-chromatographic method*.

(4) The density of a gaseous fuel mentioned in column 2 of an item in the table in subsection (1) must be analysed in accordance with ISO 6976:1995 or in accordance with a standard that is equivalent to that standard.

2.25 Frequency of analysis

Gaseous fuel of a type mentioned in column 2 of an item in the following table must be analysed for the parameter mentioned in column 3 for that item at least at the frequency mentioned in column 4 for that item.

Item	Fuel	Parameter	Frequency
1	Pipeline quality gases	Gas composition	Monthly
		Energy content	Monthly—if category 1 or 2 gas measuring equipment is used Continuous—if category 3 or 4 gas measuring equipment is used
2	All other gases (including fugitive emissions)	Gas composition Energy content	Monthly, unless the reporting corporation or registered person certifies in writing that such frequency of analysis will cause significant hardship or expense in which case the analysis may be undertaken at a frequency that will allow an unbiased estimate to be obtained

Note: The table in section 2.31 sets out the categories of gas measuring equipment.

Division 2.3.4—Method 3—emissions of carbon dioxide released from the combustion of gaseous fuels

2.26 Method 3—emissions of carbon dioxide from the combustion of gaseous fuels

(1) For subparagraph 2.19(1)(a)(iii) and subject to subsection (2), method 3 for estimating emissions of carbon dioxide is the same as method 2 under section 2.21.

(2) In applying method 2 under section 2.21, gaseous fuels must be sampled in accordance with a standard specified in the table in subsection (3).

(3) A standard for sampling a gaseous fuel mentioned column 2 of an item in the following table is the standard specified in column 3 for that item.

Item	Gaseous fuel	Standard
1	Natural gas if distributed in a pipeline	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
2	Coal seam methane that is captured for combustion	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
3	Coal mine waste gas that is captured for combustion	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
4	Compressed natural gas	ASTM F 307–02 (2007)
5	Unprocessed natural gas	ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
6	Ethane	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003)

Item	Gaseous fuel	Standard
7	Coke oven gas	ISO 10715 -1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003)
8	Blast furnace gas	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003)
9	Town gas	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
10	Liquefied natural gas	ISO 8943:2007
11	Landfill biogas that is captured for combustion	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
12	Sludge biogas that is captured for combustion	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05
13	A biogas that is captured for combustion, other than those mentioned in items 11 and 12	ISO 10715:1997 ASTM D 5287–97 (2002) ASTM F 307–02 (2007) ASTM D 5503–94 (2003) GPA 2166–05

(4) A gaseous fuel mentioned in column 2 of an item in the table in subsection (3) may also be sampled in accordance with a standard that is equivalent to a standard specified in column 3 for that item.

Division 2.3.5—Method 2—emissions of methane from the combustion of gaseous fuels

2.27 Method 2—emissions of methane from the combustion of gaseous fuels

(1) For subparagraph 2.19(1)(b)(ii) and subject to subsection (2), method 2 for estimating emissions of methane is the same as method 1 under section 2.20.

(2) In applying method 1 under section 2.20, the emission factor EF_{ijoxec} is to be obtained by using the equipment type emission factors set out in Volume 2, section 2.3.2.3 of the 2006 IPCC Guidelines corrected to gross calorific values.

Division 2.3.6—Measurement of quantity of gaseous fuels

2.28 Purpose of Division

This Division sets out how quantities of gaseous fuels combusted from the operation of a facility are to be estimated for the purpose of working out the emissions released from the combustion of that fuel.

2.29 Criteria for measurement

(1) For the purposes of calculating the combustion of gaseous fuel from the operation of a facility for a year and, in particular, for Qi in sections 2.20 and 2.21, the combustion must be estimated in accordance with this section.

Acquisition involves commercial transaction

(2) If the acquisition of the gaseous fuel involves a commercial transaction, the quantity of fuel combusted must be estimated using one of the following criteria:

- (a) the amount of the gaseous fuel, expressed in cubic metres or gigajoules, delivered for the facility during the year as evidenced by invoices issued by the vendor of the fuel (***criterion A***);
- (b) as provided in section 2.30 (***criterion AA***);
- (c) as provided in section 2.31 (***criterion AAA***).

(3) If, during a year, criterion AA, or criterion AAA using paragraph 2.31(3)(a), is used to estimate the quantity of fuel combusted, then, in each year following that year, only criterion AA, or criterion AAA using paragraph 2.31(3)(a), (respectively) is to be used.

Acquisition does not involve commercial transaction

(4) If the acquisition of the gaseous fuel does not involve a commercial transaction, the quantity of fuel combusted must be estimated using one of the following criteria:

- (a) as provided in section 2.31 (***criterion AAA***);
- (b) as provided in section 2.38 (***criterion BBB***).

2.30 Indirect measurement—criterion AA

For paragraph 2.29(2)(b), criterion AA is the amount of a gaseous fuel combusted from the operation of the facility during the year based on amounts delivered during the year (evidenced by invoices) as adjusted for the estimated change in the quantity of the stockpile of the fuel for the facility during the year.

2.31 Direct measurement—criterion AAA

(1) For paragraph 2.29(2)(c), criterion AAA is the measurement during the year of a gaseous fuel combusted from the operation of the facility.

(2) In measuring the quantity of gaseous fuel, the quantities of gas must be measured:

(a) using volumetric measurement in accordance with:

(i) for gases other than super-compressed gases—section 2.32; and

(ii) for super-compressed gases—sections 2.32 and 2.33; and

(b) using gas measuring equipment that complies with section 2.34.

(3) The measurement must be either:

(a) carried out at the point of combustion using gas measuring equipment that:

(i) is in a category specified in column 2 of an item in the table in subsection (4) according to the maximum daily quantity of gas combusted from the operation of the facility specified, for the item, in column 3 of the table; and

(ii) complies with the transmitter and accuracy requirements specified, for the item, in column 4 of the table, if the requirements are applicable to the gas measuring equipment being used; or

(b) carried out at the point of sale of the gaseous fuels using measuring equipment that complies with paragraph (a).

(4) For subsection (3), the table is as follows:

Item	Gas measuring equipment category	Maximum daily quantity of gas combusted (GJ/day)	Transmitter and accuracy requirements (% of range)
1	1	0–1750	Pressure <±0.25% Diff. pressure <±0.25% Temperature <±0.50%
2	2	1751–3500	Pressure <±0.25% Diff. pressure <±0.25% Temperature <±0.50%
3	3	3501–17500	Smart transmitters: Pressure <±0.10% Diff. pressure <±0.10% Temperature <±0.25%
4	4	17501 or more	Smart transmitters: Pressure <±0.10% Diff. pressure <±0.10% Temperature <±0.25%

(5) Paragraph (3)(b) only applies if:

(a) the change in the stockpile of the fuel for the facility for the year is less than 1% of total consumption on average for the facility during the year; and

(b) the stockpile of the fuel for the facility at the beginning of the year is less than 5% of total consumption of the fuel from the operation of the facility during the year.

2.32 Volumetric measurement—all natural gases

(1) For subparagraph 2.31(2)(a)(i) and (ii), volumetric measurement must be calculated at standard conditions and expressed in cubic metres.

(2) The volumetric measurement must be calculated using a flow computer that measures and analyses the following at the delivery location of the gaseous fuel:
(a) flow;
(b) relative density;
(c) gas composition.

(3) The volumetric flow rate must be:
(a) continuously recorded; and
(b) continuously integrated using an integration device.

(3A) The integration device must be isolated from the flow computer in such a way that, if the computer fails, the integration device will retain:
(a) the last reading that was on the computer immediately before the failure; or
(b) the previously stored information that was on the computer immediately before the failure.

(4) All measurements, calculations and procedures used in determining volume (except for any correction for deviation from the ideal gas law) must be made in accordance with:
(a) the instructions mentioned in subsection (5); or
(b) an appropriate internationally recognised standard or code.

Note: An example of an internationally recognised equivalent standard is New Zealand standard NZS 5259:2004.

(5) For paragraph (4)(a), the instructions are those mentioned in:
(a) for orifice plate measuring systems:
(i) the publication entitled *AGA Report No. 3*, *Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 3: Natural Gas Applications,* published by the American Gas Association in August 1992; or
(ii) Parts 1 to 4 of the publication entitled *ANSI/API MPMS Chapter 14.3 Part 2 (R2011) Natural Gas Fluids Measurement: Concentric, Square-Edged Orifice Meters - Part 2: Specification and Installation Requirements*, 4th edition, published by the American Petroleum Institute on 30 April 2000;
(b) for turbine measuring systems—the publication entitled *AGA Report No. 7, Measurement of Natural Gas by Turbine Meter (2006),* published by the American Gas Association on 1 January 2006;

(c) for positive displacement measuring systems—the publication entitled *ANSI B109.3—2000, Rotary Type Gas Displacement Meters*, published by the American Gas Association on 13 April 2000.

(6) Measurements must comply with Australian legal units of measurement.

(7) ***Standard conditions*** means, as measured on a dry gas basis:
(a) air pressure of 101.325 kilopascals; and
(b) air temperature of 15.0 degrees Celsius; and
(c) air density of 1.225 kilograms per cubic metre.

2.33 Volumetric measurement—super-compressed gases

(1) For subparagraph 2.31(2)(a)(ii), this section applies in relation to measuring the volume of super-compressed natural gases.

(2) If it is necessary to correct the volume for deviation from the ideal gas law, the correction must be determined using the relevant method set out in the publication entitled *AGA Report No. 8, Compressibility Factor of Natural Gas and Related Hydrocarbon Gases (1994)*, published by the American Gas Association on 1 January 1994.

(3) The measuring equipment used must calculate super-compressibility by:
(a) if the measuring equipment is category 3 or 4 equipment in accordance with the table in section 2.31—using gas composition data; or
(b) if the measuring equipment is category 1 or 2 equipment in accordance with the table in section 2.31—using an alternative method set out in the publication entitled *AGA Report No. 8, Compressibility Factor of Natural Gas and Related Hydrocarbon Gases (1994)*, published by the American Gas Association on 1 January 1994.

2.34 Gas measuring equipment—requirements

For paragraph 2.31(2)(b), gas measuring equipment that is category 3 or 4 equipment in accordance with column 2 of the table in section 2.31 must comply with the following requirements:
(a) if the equipment uses flow devices—the requirements relating to flow devices set out in section 2.35;
(b) if the equipment uses flow computers—the requirement relating to flow computers set out in section 2.36;
(c) if the equipment uses gas chromatographs—the requirements relating to gas chromatographs set out in section 2.37.

2.35 Flow devices—requirements

(1A) This section is made for paragraph 2.34(a).

(1) If the measuring equipment has flow devices that use orifice measuring systems, the flow devices must be constructed in a manner that ensures that the maximum uncertainty of the discharge coefficient is not greater than ±1.5%.

Note: The publication entitled *AGA Report No. 3, Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids Part 3: Natural Gas Applications,* published by the American Gas Association in August 1992, sets out a manner of construction that ensures that the maximum uncertainty of the discharge coefficient is not greater than ±1.5%.

(2) If the measuring equipment has flow devices that use turbine measuring systems, the flow devices must be installed in a manner that ensures that the maximum uncertainty of the flow measurement is not greater than ±1.5%.

Note: The publication entitled *AGA Report No. 8, Compressibility Factor of Natural Gas and Related Hydrocarbon Gases (1994)*, published by the American Gas Association on 1 January 1994, sets out a manner of installation that ensures that the maximum uncertainty of the flow measurement is not greater than ±1.5%.

(3) If the measuring equipment has flow devices that use positive displacement measuring systems, the flow devices must be installed in a manner that ensures that the maximum uncertainty of flow is ±1.5%.

Note: The publication entitled *ANSI B109.3—2000, Rotary Type Gas Displacement Meters*, published by the American Gas Association on 13 April 2000, sets out a manner of installation that ensures that the maximum uncertainty of flow is ±1.5%.

(4) If the measuring equipment uses any other type of flow device, the maximum uncertainty of flow measurement must not be greater than ±1.5%.

(5) All flow devices that are used by gas measuring equipment in a category specified in column 2 of an item in the table in section 2.31 must, wherever possible, be calibrated for pressure, differential pressure and temperature:
  (a) in accordance with the requirements specified, for the item, in column 4 of the table; and
  (b) taking into account the effects of static pressure and ambient temperature.

2.36 Flow computers—requirements

For paragraph 2.34(b), the requirement is that the flow computer that is used by the equipment for measuring purposes must record:
  (a) the instantaneous values for all primary measurement inputs; and
  (b) the following outputs:
    (i) instantaneous corrected volumetric flow;
    (ii) cumulative corrected volumetric flow;
    (iii) for turbine and positive displacement metering systems—instantaneous uncorrected volumetric flow;
    (iv) for turbine and positive displacement metering systems—cumulative uncorrected volumetric flow;
    (v) super-compressibility factor.

2.37 Gas chromatographs—requirements

For paragraph 2.34(c), the requirements are that gas chromatographs used by the measuring equipment must:

(a) be factory tested and calibrated using a measurement standard:
  (i) produced by gravimetric methods; and
  (ii) that uses Australian legal units of measurement; and
(b) perform gas composition analysis with an accuracy of:
  (i) ±0.15% for use in calculation of gross calorific value; and
  (ii) ±0.25% for calculation of relative density; and
(c) include a mechanism for re-calibration against a certified reference gas.

2.38 Simplified consumption measurements—criterion BBB

(1) For paragraph 2.29(4)(b), criterion BBB is the estimation of gaseous fuel in accordance with industry practice if the measuring equipment used to estimate consumption of the fuel does not meet the requirements of criterion AAA.

(2) For sources of landfill gas captured for the purpose of combustion for the production of electricity:

(a) the energy content of the captured landfill gas may be estimated:
  (i) if the manufacturer's specification for the internal combustion engine used to produce the electricity specifies an electrical efficiency factor—by using that factor; or
  (ii) if the manufacturer's specification for the internal combustion engine used to produce the electricity does not specify an electrical efficiency factor—by assuming that measured electricity dispatched for sale (sent out generation) represents 36% of the energy content of all fuel used to produce electricity; and
(b) the quantity of landfill gas captured in cubic metres may be derived from the energy content of the relevant gas set out in Part 2 of Schedule 1.

Part 2.4—Emissions released from the combustion of liquid fuels

Division 2.4.1—Preliminary

2.39 Application

This Part applies to emissions released from:

(a) the combustion of petroleum based oil (other than petroleum based oil used as fuel) or petroleum based grease, in relation to a separate instance of a source, if the total amount of oil and grease combusted in relation to the separate instance of the source is more than 5 kilolitres; and

(b) for a liquid fuel not of the kind mentioned in paragraph (a)—the combustion of liquid fuel in relation to a separate instance of a source, if the total amount of liquid fuel combusted in relation to the separate instance of the source is more than 1 kilolitre.

2.39A Definition of *petroleum based oils* for Part 2.4

In this Part:

petroleum based oils means petroleum based oils (other than petroleum based oils used as fuel).

Subdivision 2.4.1.1—Liquid fuels—other than petroleum based oils and greases

2.40 Available methods

(1) Subject to section 1.18, for estimating emissions released from the combustion of a liquid fuel, other than petroleum based oils and petroleum based greases, consumed from the operation of a facility during a year:

(a) one of the following methods must be used for estimating emissions of carbon dioxide:
   (i) method 1 under section 2.41;
   (ii) method 2 under section 2.42;
   (iii) method 3 under section 2.47;
   (iv) method 4 under Part 1.3; and

(b) one of the following methods must be used for estimating emissions of methane and nitrous oxide:
   (i) method 1 under section 2.41;
   (ii) method 2 under section 2.48.

(2) Under paragraph (1)(b), the same method must be used for estimating emissions of methane and nitrous oxide.

(3) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

Note: The combustion of liquid fuels releases emissions of carbon dioxide, methane and nitrous oxide. Method 1 may be used to estimate emissions of each of these gases. There is no method 3 or 4 for emissions of methane or nitrous oxide.

Subdivision 2.4.1.2—Liquid fuels—petroleum based oils and greases

2.40A Available methods

(1) Subject to section 1.18, for estimating emissions of carbon dioxide released from the consumption, as lubricants, of petroleum based oils or petroleum based greases, consumed from the operation of a facility during a year, one of the following methods must be used:

- (a) method 1 under section 2.48A;
- (b) method 2 under section 2.48B;
- (c) method 3 under section 2.48C.

(2) However, for incidental emissions, another method may be used that is consistent with the principles in section 1.13.

Note: The consumption of petroleum based oils and greases, as lubricants, releases emissions of carbon dioxide. Emissions of methane and nitrous oxide are not estimated directly for this fuel type.

Division 2.4.2—Method 1—emissions of carbon dioxide, methane and nitrous oxide from liquid fuels other than petroleum based oils or greases

2.41 Method 1—emissions of carbon dioxide, methane and nitrous oxide

(1) For subparagraphs 2.40(1)(a)(i) and (b)(i), method 1 for estimating emissions of carbon dioxide, methane and nitrous oxide is:

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

where:

E_{ij} is the emissions of gas type (***j***), being carbon dioxide, methane or nitrous oxide, released from the combustion of fuel type (***i***) from the operation of the facility during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type (***i***) combusted from the operation of the facility for:

(a) stationary energy purposes; and

(b) transport energy purposes;

during the year measured in kilolitres and estimated under Division 2.4.6.

EC_i is the energy content factor of fuel type ***(i)*** estimated under section 6.5.

EF_{ijoxec} is the emission factor for each gas type (***j***) released from the operation of the facility during the year (which includes the effect of an oxidation factor) measured in kilograms CO_2-e per gigajoule of fuel type (***i***) according to source as mentioned in:

(a) for stationary energy purposes—Part 3 of Schedule 1; and

(b) for transport energy purposes—Division 4.1 of Schedule 1.

(2) In this section:

stationary energy purposes means purposes for which fuel is combusted that do not involve transport energy purposes.

transport energy purposes includes purposes for which fuel is combusted that consist of any of the following:

(a) transport by vehicles registered for road use;

(b) rail transport;

(c) marine navigation;

(d) air transport.

Note: The combustion of liquid fuels produces emissions of carbon dioxide, methane and nitrous oxide.

Division 2.4.3—Method 2—emissions of carbon dioxide from liquid fuels other than petroleum based oils or greases

Subdivision 2.4.3.1—Method 2—emissions of carbon dioxide from liquid fuels other than petroleum based oils or greases

2.42 Method 2—emissions of carbon dioxide from the combustion of liquid fuels

(1) For subparagraph 2.40(1)(a)(ii), method 2 for estimating emissions of carbon dioxide is:

$$E_{ico_2} = \frac{Q_i \times EC_i \times EF_{ico_2oxec}}{1\ 000} - \gamma RCCS_{co_2}$$

where:

E_{iCO_2} is the emissions of carbon dioxide released from the combustion of fuel type (***i***) from the operation of the facility during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type (***i***) combusted from the operation of the facility during the year measured in kilolitres .

EC_i is the energy content factor of fuel type ***(i)*** estimated under section 6.5.

EF_{iCO_2oxec} is the carbon dioxide emission factor for fuel type (***i***) measured in kilograms of CO_2-e per gigajoule.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

(2) Method 2 requires liquid fuels to be sampled and analysed in accordance with the requirements in sections 2.44, 2.45 and 2.46.

2.43 Calculation of emission factors from combustion of liquid fuel

(1) For section 2.42, the emission factor $EF_{i,CO2,ox,ec}$ from the combustion of fuel type (***i***) must allow for oxidation effects and must first estimate $EF_{i,co2,ox,kg}$ in accordance with the following formula:

$$EF_{i,\ co2,ox,kg} = \frac{Ca}{100} \times OF_i \times 3.664$$

where:

C_a is the carbon in the fuel expressed as a percentage of the mass of the fuel as received, as sampled, or as combusted, as the case may be.

OF_i is the oxidation factor 1.0 applicable to liquid fuels.

Note: 3.664 converts tonnes of carbon to tonnes of carbon dioxide.

(2) The emission factor derived from the calculation in subsection (1), must be expressed in kilograms of carbon dioxide per gigajoule calculated using the following formula:

$$EF_{i,\ co2,ox,ec} = EF_{i,\ co2,ox,kg} \div \left(\frac{EC_i}{C_i}\right)$$

where:

EC_i is the energy content factor of fuel type ***(i)*** estimated under subsection 2.42(1).

C_i is the density of the fuel expressed in kilograms of fuel per thousand litres as obtained using a Standard set out in section 2.45.

Subdivision 2.4.3.2—Sampling and analysis

2.44 General requirements for sampling under method 2

(1) A sample of the liquid fuel must be derived from a composite of amounts of the liquid fuel.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard (if any).

(5) The value obtained from the samples must only be used for the delivery period or consignment of the liquid fuel for which it was intended to be representative.

2.45 Standards for analysing samples of liquid fuels

(1) Samples of liquid fuel of a type mentioned in column 2 of an item in the following table must be analysed in accordance with a standard (if any) mentioned in:

(a) for energy content analysis—column 3 for that item; and

(b) for carbon analysis—column 4 for that item; and

(c) density analysis—column 5 for that item.

Item	Fuel	Energy Content	Carbon	Density
1	Petroleum based oils (other than petroleum based oils used as fuel)	N/A	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005)
2	Petroleum based greases	N/A	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005)
3	Crude oil including crude oil condensates	ASTM D 240-02 (2007) ASTM D 4809-06	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005) ASTM D 5002 – 99 (2005)
4	Other natural gas liquids	N/A	N/A	ASTM D 1298 – 99 (2005)
5	Gasoline (other than for use as fuel in an aircraft)	ASTM D 240-02 (2007) ASTM D 4809-06	N/A	ASTM D 1298 – 99 (2005)
6	Gasoline for use as fuel in an aircraft	ASTM D 240-02 (2007) ASTM D 4809-06	N/A	ASTM D 1298 – 99 (2005)
7	Kerosene (other than for use as fuel in an aircraft)	ASTM D 240-02 (2007) ASTM D 4809-06	N/A	ASTM D 1298 – 99 (2005) ASTM D 4052 – 96 (2002) e1
8	Kerosene for use as fuel in an aircraft	ASTM D 240-02 (2007) ASTM D 4809-06	N/A	ASTM D 1298 – 99 (2005) ASTM D 4052 – 96 (2002) e1
9	Heating oil	ASTM D 240-02 (2007) ASTM D 4809-06	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005)
10	Diesel oil	ASTM D 240-02 (2007) ASTM D 4809-06	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005)
11	Fuel oil	ASTM D 240-02 (2007) ASTM D 4809-06	ASTM D 5291-02 (2007)	ASTM D 1298 – 99 (2005)
12	Liquefied aromatic hydrocarbons	N/A	N/A	ASTM D 1298 – 99 (2005)
13	Solvents if mineral turpentine or white spirits	N/A	N/A	N/A
14	Liquefied Petroleum Gas	N/A	ISO 7941:1988	ISO 6578:1991 ISO 8973:1997 ASTM D 1657 – 02

Item	Fuel	Energy Content	Carbon	Density
15	Naphtha	N/A	N/A	N/A
16	Petroleum coke	N/A	N/A	N/A
17	Refinery gas and liquids	N/A	N/A	N/A
18	Refinery coke	N/A	N/A	N/A
19	Petroleum based products other than: (a) petroleum based oils and petroleum based greases mentioned in items 1and 2 (b) the petroleum based products mentioned in items 3 to 18	N/A	N/A	N/A
20	Biodiesel	N/A	N/A	N/A
21	Ethanol for use as a fuel in an internal combustion engine	N/A	N/A	N/A
22	Biofuels other than those mentioned in items 20 and 21	N/A	N/A	N/A

(2) A liquid fuel of a type mentioned in column 2 of an item in the table in subsection (1) may also be analysed for energy content, carbon and density in accordance with a standard that is equivalent to a standard mentioned in columns 3, 4 and 5 for that item.

(3) Analysis must be undertaken by an accredited laboratory or by a laboratory that meets requirements equivalent to those in AS ISO/IEC 17025:2005.

2.46 Frequency of analysis

Liquid fuel of a type mentioned in column 2 of an item in the following table must be analysed for the parameter mentioned in column 3 for that item at least at the frequency mentioned in column 4 for that item.

Item	Fuel	Parameter	Frequency
1	All types of liquid fuel	Carbon	Quarterly or by delivery of the fuel
2	All types of liquid fuel	Energy	Quarterly or by delivery of the fuel

Division 2.4.4—Method 3—emissions of carbon dioxide from liquid fuels other than petroleum based oils or greases

2.47 Method 3—emissions of carbon dioxide from the combustion of liquid fuels

(1) For subparagraph 2.40(1)(a)(iii) and subject to this section, method 3 for estimating emissions of carbon dioxide is the same as method 2 under section 2.42.

(2) In applying method 2 under section 2.42, liquid fuels must be sampled in accordance with a standard specified in the table in subsection (3).

(3) A standard for sampling a liquid fuel of a type mentioned in column 2 of an item in the following table is specified in column 3 for that item.

item	Liquid Fuel	Standard
1	Petroleum based oils (other than petroleum based oils used as fuel)	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06
2	Petroleum based greases	
3	Crude oil including crude oil condensates	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
4	Other natural gas liquids	ASTM D1265 – 05
5	Gasoline (other than for use as fuel in an aircraft)	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
6	Gasoline for use as fuel in an aircraft	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
7	Kerosene (other than for use as fuel in an aircraft)	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
8	Kerosene for use as fuel in an aircraft	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)

item	Liquid Fuel	Standard
9	Heating oil	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
10	Diesel oil	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
11	Fuel oil	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
12	Liquefied aromatic hydrocarbons	ASTM D 4057 – 06
13	Solvents if mineral turpentine or white spirits	ASTM D 4057 – 06
14	Liquefied Petroleum Gas	ASTM D1265 – 05) ISO 4257:2001
15	Naphtha	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06
16	Petroleum coke	ASTM D 4057 – 06
17	Refinery gas and liquids	ASTM D 4057 – 06
18	Refinery coke	ASTM D 4057 – 06
19	Petroleum based products other than: (a) petroleum based oils and petroleum based greases mentioned in items 1 and 2; and (b) the petroleum based products mentioned in items 3 to 18	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06
20	Biodiesel	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)
21	Ethanol for use as a fuel in an internal combustion engine	ASTM D 4057 – 06
22	Biofuels other than those mentioned in items 20 and 21	ISO 3170:2004 ISO 3171:1988 ASTM D 4057 – 06 ASTM D 4177 – 95 (2005)

(4) A liquid fuel may also be sampled in accordance with a standard that is equivalent to a standard set out in the table in subsection (3) in relation to that liquid fuel.

Division 2.4.5—Method 2—emissions of methane and nitrous oxide from liquid fuels other than petroleum based oils or greases

2.48 Method 2—emissions of methane and nitrous oxide from the combustion of liquid fuels

(1) For subparagraph 2.40(1)(b)(ii) and subject to subsection (2), method 2 for estimating emissions of methane and nitrous oxide is the same as method 1 under section 2.41.

(2) In applying method 1 in section 2.41, the emission factor $\boldsymbol{EF_{ijoxec}}$ is taken to be the emission factor set out in:

(a) for combustion of fuel by vehicles manufactured after 2004—columns 5 and 6 of the table in Division 4.2 of Part 4 of Schedule 1; and

(b) for combustion of fuel by trucks that meet the design standards mentioned in column 3 of the table in Division 4.3 of Part 4 of Schedule 1—columns 6 and 7 of the table in that Division.

Division 2.4.5A—Methods for estimating emissions of carbon dioxide from petroleum based oils or greases

2.48A Method 1—estimating emissions of carbon dioxide using an estimated oxidation factor

(1) For paragraph 2.40A(1)(a), method 1 for estimating emissions of carbon dioxide from the consumption of petroleum based oils or petroleum based greases using an estimated oxidation factor is:

$$E_{pogco2} = Q_{pog} \times EC_{pogco2} \times \frac{EF_{pogco2oxec}}{1\ 000}$$

where:

$\boldsymbol{E_{pogco2}}$ is the emissions of carbon dioxide released from the consumption of petroleum based oils or petroleum based greases from the operation of the facility during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_{pog}}$ is the quantity of petroleum based oils or petroleum based greases consumed from the operation of the facility, estimated in accordance with Division 2.4.6.

$\boldsymbol{EC_{pogco2}}$ is the energy content factor of petroleum based oils or petroleum based greases measured in gigajoules per kilolitre as mentioned in Part 3 of Schedule 1.

$\boldsymbol{EF_{pogco2oxec}}$ has the meaning given in subsection (2).

(2) $\boldsymbol{EF_{pogco2oxec}}$ is:

(a) the emission factor for carbon dioxide released from the operation of the facility during the year (which includes the effect of an oxidation factor) measured in kilograms CO_2-e per gigajoule of the petroleum based oils or petroleum based greases as mentioned in Part 3 of Schedule 1; or

(b) to be estimated as follows:

$$EF_{pogco2oxec} = OF_{pog} \times EF_{pogco2ec}$$

where:

$\boldsymbol{OF_{pog}}$ is the estimated oxidation factor for petroleum based oils or petroleum based greases.

$\boldsymbol{EF_{pogco2ec}}$ is 69.9.

(3) For $\boldsymbol{OF_{pog}}$ in paragraph (2)(b), estimate as follows:

$$OF_{pog} = \frac{Q_{pog} - \text{Oil Transferred Offsite}_{pog}}{Q_{pog}}$$

where:

Q_{pog} is the quantity of petroleum based oils or petroleum based greases consumed from the operation of the facility, estimated in accordance with Division 2.4.6.

$\textit{\textbf{Oil Transferred Offsite}}_{pog}$ is the quantity of oils, derived from petroleum based oils or petroleum based greases, transferred outside the facility, and estimated in accordance with Division 2.4.6.

2.48B Method 2—estimating emissions of carbon dioxide using an estimated oxidation factor

For paragraph 2.40A(1)(b), method 2 is the same as method 1 but the emission factor $EF_{pogco2ec}$ must be determined in accordance with Division 2.4.3.

2.48C Method 3—estimating emissions of carbon dioxide using an estimated oxidation factor

For paragraph 2.40A(1)(c), method 3 is the same as method 1 but the emission factor $EF_{pogco2ec}$ must be determined in accordance with Division 2.4.4.

Division 2.4.6—Measurement of quantity of liquid fuels

2.49 Purpose of Division

This Division sets out how quantities of liquid fuels combusted from the operation of a facility are to be estimated for the purpose of working out the emissions released from the combustion of that fuel.

2.50 Criteria for measurement

(1) For the purpose of calculating the combustion of a liquid fuel from the operation of a facility for a year and, in particular, for Q_i in sections 2.41 and 2.42 the combustion must be estimated in accordance with this section.

Acquisition involves commercial transaction

(2) If the acquisition of the liquid fuel involves a commercial transaction, the quantity of fuel combusted must be estimated using one of the following criteria:
  (a) the amount of the liquid fuel delivered for the facility during the year as evidenced by invoices issued by the vendor of the fuel (***criterion A***);
  (b) as provided in section 2.51 (***criterion AA***);
  (c) as provided in section 2.52 (***criterion AAA***).

(3) If, during a year, criterion AA, or criterion AAA using paragraph 2.52(2)(a), is used to estimate the quantity of fuel combusted then, in each year following that year, only criterion AA, or criterion AAA using paragraph 2.52(2)(a), (respectively) may be used.

Acquisition does not involve commercial transaction

(4) If the acquisition of the liquid fuel does not involve a commercial transaction, the quantity of fuel combusted must be estimated using one of the following criteria:
  (a) as provided in paragraph 2.52(2)(a) (***criterion AAA***);
  (b) as provided in section 2.53 (***criterion BBB***).

2.51 Indirect measurement—criterion AA

For paragraph 2.50(2)(b), criterion AA is the amount of the liquid fuel combusted from the operation of the facility during the year based on amounts delivered during the year (evidenced by invoices) as adjusted for the estimated change in the quantity of the stockpile of the fuel for the facility during the year.

2.52 Direct measurement—criterion AAA

(1) For paragraph 2.50(2)(c), criterion AAA is the measurement during the year of the liquid fuel combusted from the operation of the facility.

(2) The measurement must be carried out:

(a) at the point of combustion at ambient temperatures and converted to standard temperatures, using measuring equipment calibrated to a measurement requirement; or

(b) at ambient temperatures and converted to standard temperatures, at the point of sale of the liquid fuel, using measuring equipment calibrated to a measurement requirement.

(3) Paragraph (2)(b) only applies if:

(a) the change in the stockpile of fuel for the facility for the year is less than 1% of total combustion on average for the facility during the year; and

(b) the stockpile of the fuel for the facility at the beginning of the year is less than 5% of total combustion from the operation of the facility for the year.

2.53 Simplified consumption measurements—criterion BBB

For paragraph 2.50(4)(b), criterion BBB is the estimation of the combustion of a liquid fuel for the year using accepted industry measuring devices or, in the absence of such measuring devices, in accordance with industry practice if the equipment used to measure consumption of the fuel is not calibrated to a measurement requirement.

Part 2.5—Emissions released from fuel use by certain industries

2.54 Application

This Part applies to emissions from petroleum refining, solid fuel transformation (coke ovens) and petrochemical production.

Division 2.5.1—Energy—petroleum refining

2.55 Application

This Division applies to petroleum refining.

2.56 Methods

(1) If:

(a) the operation of a facility is constituted by petroleum refining; and

(b) the refinery combusts fuels for energy;

then the methods for estimating emissions during a year from that combustion are as provided in Parts 2.2, 2.3 and 2.4.

(2) The method for estimating emissions from the production of hydrogen by the petroleum refinery must be in accordance with the method set out in section 5 of the API Compendium.

(3) Fugitive emissions released from the petroleum refinery must be estimated using methods provided for in Chapter 3.

Division 2.5.2—Energy—manufacture of solid fuels

2.57 Application

This Division applies to solid fuel transformation through the pyrolysis of coal or the coal briquette process.

2.58 Methods

(1) One or more of the following methods must be used for estimating emissions during the year from combustion of fuels for energy in the manufacture of solid fuels:

(a) if a facility is constituted by the manufacture of solid fuel using coke ovens as part of an integrated metalworks—the methods provided in Part 4.4 must be used; and

(b) in any other case—one of the following methods must be used:

(i) method 1 under subsection (3);

(ii) method 2 under subsections (4) to (7);

(iii) method 3 under subsections (8) to (10);

(iv) method 4 under Part 1.3.

(2) These emissions are taken to be emissions from fuel combustion.

Method 1

(3) Method 1, based on a carbon mass balance approach, is:

Step 1 Work out 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:

$$\Sigma_i \ CCF_i \times Q_i$$

where:

Σ

$\boldsymbol{\Sigma_i}$ means the sum of the carbon content values obtained for all fuel types (***i***) or carbonaceous input material.

$\boldsymbol{CCF_i}$ is the carbon content factor mentioned in Schedule 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.

$\boldsymbol{Q_i}$ is the quantity of fuel type (***i***) or carbonaceous input material delivered for the activity during the year, measured in an appropriate unit and estimated in accordance with criterion A in Divisions 2.2.5, 2.3.6 and 2.4.6.

Step 2 Work out the carbon content in products (***p***) leaving the activity during the year, measured in tonnes of carbon, as follows:

$$\Sigma_p \ CCF_p \times A_p$$

where:

$\boldsymbol{\Sigma_p}$ means the sum of the carbon content values obtained for all product types (***p***).

$\boldsymbol{CCF_p}$ is the carbon content factor, measured in tonnes of carbon, for each tonne of product type (***p***) produced during the year.

$\boldsymbol{A_p}$ is the quantity of product types (***p***) produced leaving the activity during the year, measured in tonnes.

Step 3 Work out 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:

$$\Sigma_r \ CCF_r \times Y_r$$

where:

$\boldsymbol{\Sigma_r}$ means the sum of the carbon content values obtained for all waste by-product types (***r***).

$\boldsymbol{CCF_r}$ is the carbon content factor, measured in tonnes of carbon, for each tonne of waste by-product types (***r***).

$\boldsymbol{Y_r}$ is the quantity of waste by-product types (***r***) leaving the activity during the year, measured in tonnes.

Step 4 Work out the carbon content in the amount of the change in stocks of inputs, products and waste by-products held within the boundary of the activity during the year, measured in tonnes of carbon, as follows:

$$\Sigma_i \ CCF_i \times \Delta S_{qi} + \Sigma_p \ CCF_p \times \Delta S_{ap} + \Sigma_r \ CCF_r \times \Delta S_{yr}$$

where:

$\boldsymbol{\Sigma_i}$ has the same meaning as in step 1.

$\boldsymbol{CCF_i}$ has the same meaning as in step 1.

$\boldsymbol{\Delta S_{qi}}$ is the change in stocks of fuel type (***i***) for the activity and held within the boundary of the activity during the year, measured in tonnes.

$\boldsymbol{\Sigma_p}$ has the same meaning as in step 2.

$\boldsymbol{CCF_p}$ has the same meaning as in step 2.

$\boldsymbol{\Delta S_{ap}}$ is the change in stocks of product types ***(p)*** produced by the activity and held within the boundary of the activity during the year, measured in tonnes.

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the change 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 Work out the emissions of carbon dioxide released from the operation of the activity during the year, measured in CO_2-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 the year.

Method 2

(4) Subject to subsections (5) to (7), method 2 is the same as method 1 under subsection (3).

(5) In applying method 1 as method 2, step 4 in subsection (3) is to be omitted and the following step 4 substituted.

Step 4 Work out the carbon content in the amount of the change in stocks of inputs, products and waste by-products held within the boundary of the activity during the year, measured in tonnes of carbon, as follows:

$$\Sigma_i\ CCF_i \times \Delta S_{qi} + \Sigma_p\ CCF_p \times \Delta S_{ap} + \Sigma_r\ CCF_r \times \Delta S_{yr} + \alpha\,\gamma RCCS_{co_2}$$

where:

Σ_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

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

Σ_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

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

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the change 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.

α is the factor $\frac{1}{3.664}$ for converting the mass of carbon dioxide to a mass of carbon.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$\boldsymbol{RCCS_{CO_2}}$ is carbon dioxide captured for permanent storage, measured in cubic metres in accordance with Division 1.2.3.

(6) If a fuel type (***i***) or carbonaceous input material delivered for the activity during the year accounts for more than 5% of total carbon input for the activity, based on a calculation using the factors specified in Schedule 3, sampling and analysis of fuel type ***(i)*** or carbonaceous input material must be carried out to determine its carbon content.

(7) The sampling and analysis is to be carried out using the sampling and analysis provided for in Divisions 2.2.3, 2.3.3 and 2.4.3 that apply to the combustion of solid, gaseous and liquid fuels.

Method 3

(8) Subject to subsections (9) and (10), method 3 is the same as method 2 under subsections (4) to (7).

(9) If a fuel type (***i***) or carbonaceous input material delivered for the activity during the year accounts for more than 5% of total carbon input for the activity, based on a calculation using the factors specified in Schedule 3, sampling and analysis of fuel type ***(i)*** or carbonaceous input material must be carried out to determine its carbon content.

(10) The sampling and analysis is to be carried out using the methods set out in Divisions 2.2.4, 2.3.4 and 2.4.4 that apply to the combustion of solid, gaseous and liquid fuels.

Division 2.5.3—Energy—petrochemical production

2.59 Application

This Division applies to petrochemical production (where fuel is consumed as a feedstock).

2.60 Available methods

(1) Subject to section 1.18 one of the following methods must be used for estimating emissions released during a year from the operation of a facility that is constituted by an activity that is petrochemical production:
  (a) method 1 under section 2.61;
  (b) method 2 under section 2.62;
  (c) method 3 under section 2.63;
  (d) method 4 under Part 1.3.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

2.61 Method 1—petrochemical production

Method 1, based on a carbon mass balance approach, is:

Step 1 Calculate the carbon content in all fuel types (***i***) delivered for the activity during the year as follows:

$$\Sigma_i CCF_i \times Q_i$$

where:

Σ_i means sum the carbon content values obtained for all fuel types (***i***).

CCF_i is the carbon content factor measured in tonnes of carbon for each tonne of fuel type (***i***) as mentioned in Schedule 3 consumed in the operation of the activity.

Q_i is the quantity of fuel type (***i***) delivered for the activity during the year measured in tonnes and estimated in accordance with criterion A in Divisions 2.2.5, 2.3.6 and 2.4.6.

Step 2 Calculate the carbon content in products (***p***) leaving the activity during the year as follows:

$$\Sigma_p CCF_p \times A_p$$

where:

Σ_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 (***p***).

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

Step3 Calculate the carbon content in waste by-products (r) leaving the activity, other than as an emission of greenhouse gas, during the year as follows:

$$\Sigma_r \, CCF_r \times Y_r$$

where:

Σ_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 (***r***).

Y_r is the quantity of waste by-product (***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 as follows:

$$\Sigma_i \, CCF_i \times \Delta S_{qi} + \Sigma_p \, CCF_p \times \Delta S_{ap} + \Sigma_r \, CCF_r \times \Delta S_{yr}$$

where:

Σ_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.

Σ_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 products produced ***(p)*** by the activity and held within the boundary of the activity during the year measured in tonnes.

Σ_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-products (***r***) produced by 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 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 activity during a year.

2.62 Method 2—petrochemical production

(1) Subject to subsections (2) and (3), method 2 is the same as method 1 under section 2.61 but sampling and analysis of fuel types ***(i)*** is used to determine carbon content of the fuel.

(2) The sampling and analysis is to be carried out using the methods set out in Divisions 2.2.3, 2.3.3 and 2.4.3 that apply to the combustion of solid, liquid or gaseous fuels.

(3) In applying method 1 as method 2, step 4 in section 2.61 is to be omitted and the following step 4 substituted:

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 as follows:

$$\sum_i CCF_i \times \Delta S_{qi} + \sum_p CCF_p \times \Delta S_{ap} + \sum_r CCF_r \times \Delta S_{yr} + \alpha \gamma RCCS_{co_2}$$

where:

Σ_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.

Σ_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 products produced (***p***) by the activity and held within the ***boundary*** of the activity during the year measured in tonnes.

Σ_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-products (***r***) produced by the activity and held within the boundary of the activity during the year measured in tonnes.

α is the factor $\frac{1}{3.664}$ for converting the mass of carbon dioxide to a mass of carbon.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent ***storage*** measured in cubic metres in accordance with Division 1.2.3.

2.63 Method 3—petrochemical production

(1) Subject to subsections (2) and (3), method 3 is the same as method 1 in section 2.61 but the sampling and analysis of fuel types ***(i)*** is used to determine carbon content of the fuel.

(2) The sampling and analysis is to be carried out using the methods set out in Divisions 2.2.4, 2.3.4 and 2.4.4 that apply to the combustion of solid, liquid or gaseous fuels.

(3) In applying method 1 as method 3, step 4 in section 2.61 is to be omitted and the following step 4 substituted.

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 as follows:

$$\Sigma_i \ CCF_i \times \Delta S_{qi} + \Sigma_p \ CCF_p \times \Delta S_{ap} + \Sigma_r \ CCF_r \times \Delta S_{yr} + \alpha\gamma RCCS_{co_2}$$

where:

$\boldsymbol{\Sigma_i}$ has the same meaning as in step 1.

$\boldsymbol{CCF_i}$ has the same meaning as in step 1.

$\boldsymbol{\Delta S_{qi}}$ 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.

$\boldsymbol{\Sigma_p}$ has the same meaning as in step 2.

$\boldsymbol{CCF_p}$ has the same meaning as in step 2.

$\boldsymbol{\Delta S_{ap}}$ is the increase in stocks of products produced (***p***) by the activity and held within the boundary of the activity during the year measured in tonnes.

$\boldsymbol{\Sigma_r}$ has the same meaning as in step 3.

$\boldsymbol{CCF_r}$ has the same meaning as in step 3.

$\boldsymbol{\Delta S_{yr}}$ is the increase in stocks of waste by-products (***r***) produced by the activity and held within the boundary of the activity during the year measured in tonnes.

$\boldsymbol{\alpha}$ is the factor $\frac{1}{3.664}$ for converting the mass of carbon dioxide to a mass of carbon.

$\boldsymbol{\gamma}$ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$\boldsymbol{RCCS_{CO_2}}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

Part 2.6—Blended fuels

2.64 Purpose

This Part sets out how to determine the amounts of each kind of fuel that is in a blended fuel.

2.65 Application

This Part sets out how to determine the amount of each fuel type (***i***) that is in a blended fuel if that blended fuel is a solid fuel or a liquid fuel.

2.66 Blended solid fuels

(1) In determining the amounts of each kind of fuel that is in a blended solid fuel, a person may adopt the outcome of the sampling and analysis done by the manufacturer of the fuel if:

  (a) the sampling has been done in accordance with subsections 2.12(3) and (4); and

  (b) the analysis has been done in accordance with one of the following standards or a standard that is equivalent to one of those standards:

    (i) CEN/TS15440:2006;

    (ii) ASTM D6866—10.

(2) The person may use his or her own sampling and analysis of the fuel if the sampling and analysis complies with the requirements of paragraphs (1)(a) and (b).

2.67 Blended liquid fuels

The person may adopt the manufacturer's determination of each kind of fuel that is in a blended liquid fuel or adopt the analysis arrived at after doing both of the following:

  (a) sampling the fuel in accordance with a standard mentioned in subsections 2.47(3) and (4);

  (b) analysing the fuel in accordance with ASTM: D6866—10 or a standard that is equivalent to that standard.

Part 2.7—Estimation of energy for certain purposes

2.68 Amount of energy consumed without combustion

For paragraph 4.22(1)(b) of the Regulations:

(a) the energy is to be measured:
  (i) for solid fuel—in tonnes estimated under Division 2.2.5; or
  (ii) for gaseous fuel—in cubic metres estimated under Division 2.3.6; or
  (iii) for liquid fuel—in kilolitres estimated under Division 2.4.6; and
  (iv) for electricity—in kilowatt hours:
    (A) worked out using the evidence mentioned in paragraph 6.5(2)(a); or
    (B) if the evidence mentioned in paragraph 6.5(2)(a) is unavailable—estimated in accordance with paragraph 6.5(2)(b).

(b) the reporting threshold is:
  (i) for solid fuel—20 tonnes; or
  (ii) for gaseous fuel—13 000 cubic metres; or
  (iii) for liquid fuel—15 kilolitres; or
  (iv) for electricity consumed from a generating unit at the facility—that each generating unit has a maximum capacity to produce at least 0.5 megawatts of electricity and produces over 100 000 kilowatt hours of electricity in a reporting year; or
  (v) for electricity consumed that was not generated by a generating unit at the facility—20 000 kilowatt hours.

Example: A fuel is consumed without combustion when it is used as a solvent or a flocculent, or as an ingredient in the manufacture of products such as paints, solvents or explosives.

2.69 Apportionment of fuel consumed as carbon reductant or feedstock and energy

(1) This section applies, other than for Division 2.5.3, if:
  (a) a fuel type as provided for in a method is consumed from the operation of a facility as either a reductant or a feedstock; and
  (b) the fuel is combusted for energy; and
  (c) the equipment used to measure the amount of the fuel for the relevant purpose was not calibrated to a measurement requirement.

Note: Division 2.5.3 deals with petrochemicals. For petrochemicals, all fuels, whether used as a feedstock, a reductant or combusted as energy are reported as energy.

(2) The amount of the fuel type consumed as a reductant or a feedstock may be estimated:
  (a) in accordance with industry measuring devices or industry practice; or

(b) if it is not practicable to estimate as provided for in paragraph (a)—to be the whole of the amount of the consumption of that fuel type from the operation of the facility.

(3) The amount of the fuel type combusted for energy may be estimated as the difference between the total amount of the fuel type consumed from the operation of the facility and the estimated amount worked out under subsection (2).

2.70 Amount of energy consumed in a cogeneration process

(1) For subregulation 4.23(3) of the Regulations and subject to subsection (3), the method is the efficiency method.

(2) The ***efficiency method*** is as described in the publication entitled *Allocation of Emissions from a Combined Heat and Power (CHP) Plant Guide to calculation worksheets (September 2006) v1.0* issued by the World Resource Institute and World Business Council for Sustainable Development.

(3) Where heat is to be used mainly for producing mechanical work, the work potential method may be used.

(4) The ***work potential method*** is as described in the publication entitled *Allocation of Emissions from a Combined Heat and Power (CHP) Plant Guide to calculation worksheets (September 2006) v1.0* issued by the World Resource Institute and World Business Council for Sustainable Development.

2.71 Apportionment of energy consumed for electricity, transport and for stationary energy

Subject to section 2.70, the amount of fuel type (***i***) consumed by a reporting corporation or registered person that is apportioned between electricity generation, transport (excluding international bunker fuels) and other stationary energy purposes may be determined using the records of the corporation or registered person if the records are based on the measurement equipment used by the corporation or the registered person to measure consumption of the fuel types.

Chapter 3—Fugitive emissions

Part 3.1—Preliminary

3.1 Outline of Chapter

This Chapter provides for fugitive emissions from the following:

(a) coal mining (see Part 3.2);
(b) oil and natural gas (see Part 3.3);
(c) carbon capture and storage (see Part 3.4).

Part 3.2—Coal mining—fugitive emissions

Division 3.2.1—Preliminary

3.2 Outline of Part

This Part provides for fugitive emissions from coal mining, as follows:

(a) underground mining activities (see Division 3.2.2);
(b) open cut mining activities (see Division 3.2.3);
(c) decommissioned underground mines (see Division 3.2.4).

Division 3.2.2—Underground mines

Subdivision 3.2.2.1—Preliminary

3.3 Application

This Division applies to fugitive emissions from underground mining activities (other than decommissioned underground mines).

3.4 Available methods

(1) Subject to section 1.18, for estimating emissions released during a year from the operation of a facility that is constituted by underground mining activities (other than decommissioned underground mines) the methods as set out in this section must be used.

Methane from extraction of coal

(2) Method 4 under section 3.6 must be used for estimating fugitive emissions of methane that result from the extraction of coal from the underground mine.

Note: There is no method 1, 2 or 3 for subsection (2).

Carbon dioxide from extraction of coal

(3) Method 4 under section 3.6 must be used for estimating fugitive emissions of carbon dioxide that result from the extraction of coal from the underground mine.

Note: There is no method 1, 2 or 3 for subsection (3).

Flaring

(4) For estimating emissions released from coal mine waste gas flared from the underground mine:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:
  (i) method 1 under section 3.14;
  (ii) method 2 under section 3.15;
  (iii) method 3 under section 3.16; and

(b) one of the following methods must be used for estimating emissions of methane released:
  (i) method 1 under section 3.14;
  (ii) method 2 under section 3.15A; and

(c) one of the following methods must be used for estimating emissions of nitrous oxide released:
  (i) method 1 under section 3.14;
  (ii) method 2 under section 3.15A.

Note: The flaring of coal mine waste gas releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 under section 3.14 or method 2 under section 3.15A is a reference to these gases. The same formula in Method 1 is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide and no method 3 or 4 for emissions of methane or nitrous oxide.

Venting or other fugitive release before extraction of coal

(5) Method 4 under Part 1.3 must be used for estimating fugitive emissions of each gas type, being carbon dioxide and methane, that result from venting or other fugitive release of gas from the underground mine before coal is extracted from the mine.

Note: There is no method 1, 2 or 3 for subsection (5).

Post-mining activities

(6) Method 1 under section 3.17 must be used for estimating fugitive emissions of methane that result from post-mining activities related to a gassy mine.

Note: There is no method 2, 3 or 4 for subsection (6).

(7) However, for incidental emissions, another method may be used that is consistent with the principles in section 1.13.

Subdivision 3.2.2.2—Fugitive emissions from extraction of coal

3.5 Method 1—extraction of coal

For subsection 3.32(1), method 1 is:

$$E_j = Q \times EF_j$$

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 CO_2-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 CO_2-e tonnes per tonne of run-of-mine coal extracted from the mine, as follows:

(a) for a gassy mine—0.363;
(b) for a non-gassy mine—0.010.

3.6 Method 4—extraction of coal

(1) For subsections 3.4(2) and (3), method 4 is:

$$E_j = CO_{2\text{-}e_{j\,gen,\,total}} - \gamma_j \left(Q_{ij,cap} + Q_{ij,flared} + Q_{ijtr}\right)$$

where:

E_j is the fugitive emissions of gas type (***j***) that result from the extraction of coal from the mine during the year, measured in CO_2-e tonnes.

$CO_2\text{-}e_{\,j\,gen,\,total}$ is the total mass of gas type (***j***) generated from the mine during the year before capture and flaring is undertaken at the mine, measured in CO_2-e tonnes and estimated using the direct measurement of emissions in accordance with subsection (2).

γ_j is the factor for converting a quantity of gas type (***j***) from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes, being:

(a) for methane—$6.784 \times 10^{-4} \times 25$; and

(b) for carbon dioxide—1.861×10^{-3}.

$Q_{ij,cap}$ is the quantity of gas type (***j***) in coal mine waste gas type (***i***) captured for combustion from the mine and used during the year, measured in cubic metres and estimated in accordance with Division 2.3.6.

$Q_{ij,flared}$ is the quantity of gas type (***j***) in coal mine waste gas type (***i***) flared from the mine during the year, measured in cubic metres and estimated in accordance with Division 2.3.6.

Q_{ijtr} is the quantity of gas type (***j***) in coal mine waste gas type (***i***) transferred out of the mining activities during the year measured in cubic metres.

(2) The direct measurement of emissions released from the extraction of coal from an underground mine during a year by monitoring the gas stream at the underground mine may be undertaken by one of the following:

(a) continuous emissions monitoring (***CEM***) in accordance with Part 1.3;

(b) periodic emissions monitoring (***PEM***) in accordance with sections 3.7 to 3.13.

Note: Any estimates of emissions must be consistent with the principles in section 1.13.

(3) For Q_{ijtr} in subsection (1), the quantity of gas type (***j***) must be estimated in accordance with Division 2.3.6 as if a reference in that Division to quantities of gaseous fuels combusted from the operation of a facility was a reference to quantities of gaseous fuels transferred out of the operation of a facility.

3.7 Estimation of emissions

(1) To obtain an estimate of the mass emissions rate of gas (***j***), being methane and carbon dioxide, at the time of measurement at the underground mine, the formula in subsection 1.21(1) must be applied.

(2) The mass of emissions estimated under the formula must be converted into CO_2-e tonnes.

(3) The average mass emission rate for gas type (***j***) measured in CO_2–e tonnes per hour for a year must be calculated from the estimates obtained under subsections (1) and (2).

(4) The total mass of emissions of gas type (***j***) from the underground mine for the year is calculated by multiplying the average emissions rate obtained under subsection (3) by the number of hours during the year.

3.8 Overview—use of equipment

The following requirements apply to the use of PEM equipment:

(a) the requirements in section 3.9 about location of the sampling positions for the PEM equipment;

(b) the requirements in section 3.10 about measurement of volumetric flow rates in a gas stream;

(c) the requirements in section 3.11 about measurement of the concentrations of gas type (***j***) in the gas stream;

(d) the requirements in section 3.12 about representative data.

(e) the requirements in section 3.13 about performance characteristics of equipment.

3.9 Selection of sampling positions for PEM

For paragraph 3.8(a), an appropriate standard or applicable State or Territory legislation must be complied with for the location of sampling positions for PEM equipment.

Note: Appropriate standards include:

- AS 4323.1—1995/Amdt 1-1995, *Stationary source emissions—Selection of sampling positions*
- USEPA Method 1—*Sample and velocity traverses for stationary sources (2000)*

3.10 Measurement of volumetric flow rates by PEM

For paragraph 3.8(b), the measurement of the volumetric flow rates by PEM of the gas stream must be undertaken in accordance with an appropriate standard or applicable State or Territory legislation.

Note: Appropriate standards include:

- ISO 14164:1999 *Stationary source emissions. Determination of the volume flowrate of gas streams in ducts – automated method*
- ISO 10780:1994 *Stationary source emissions. Measurement of velocity and volume flowrate of gas streams in ducts*
- USEPA Method 2—*Determination of stack gas velocity and volumetric flow rate (Type S Pitot tube) (2000)*
- USEPA Method 2A—*Direct measurement of gas volume through pipes and small ducts (2000)*.

3.11 Measurement of concentrations by PEM

For paragraph 3.8(c), the measurement of the concentrations of gas type (***j***) in the gas stream by PEM must be undertaken in accordance with an appropriate standard or applicable State or Territory legislation.

Note: Appropriate standards include USEPA—Method 3C—*Determination of carbon dioxide, methane, nitrogen and oxygen from stationary sources (1996)*.

3.12 Representative data for PEM

(1) For paragraph 3.8(d), sampling by PEM must be undertaken during the year for a sufficient duration to produce representative data that may be reliably extrapolated to provide estimates of emissions across the full range of operating conditions for that year.

(2) Emission estimates of PEM equipment must also be consistent with the principles in section 1.13.

3.13 Performance characteristics of equipment

For paragraph 3.8(e), the performance characteristics of PEM equipment must be consistent with an appropriate standard or applicable State or Territory legislation.

Note: The performance characteristics of PEM equipment includes calibration.

Subdivision 3.2.2.3—Emissions released from coal mine waste gas flared

3.14 Method 1—coal mine waste gas flared

For subparagraph 3.4(4)(a)(i) and paragraphs 3.4(4)(b) and (c), method 1 is:

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

where:

$E_{(fl)ij}$ is the emissions of gas type (***j***) released from coal mine waste gas (***i***) flared from the mine during the year, measured in CO_2-e tonnes.

$Q_{i,flared}$ is the quantity of coal mine waste gas (***i***) flared from the mine during the year, measured in cubic metres and estimated under Division 2.3.6.

EC_i is the energy content factor of coal mine waste gas (***i***) mentioned in item 19 of Schedule 1, measured in gigajoules per cubic metre.

EF_{ij} is the emission factor for gas type (***j***) and coal mine waste gas (***i***) mentioned in item 19 of Schedule 1, measured in CO_2-e kilograms per gigajoule.

OF_{if} is 0.98, which is the destruction efficiency of coal mine waste gas (***i***) flared.

3.15 Method 2—emissions of carbon dioxide from coal mine waste gas flared

For subparagraph 3.4(4)(a)(ii), method 2 is:

$$E_{ico_2} = \frac{Q_k \times EC_i \times EF_k}{1000} \times OF_i + QCO_2$$

where:

E_{iCO_2} is the emissions of CO_2 released from coal mine waste gas (***i***) flared from the mine during the year, measured in CO_2-e tonnes.

EC_i is the energy content factor of the methane (***k***) within coal mine waste gas (***i***) mentioned in item 19 of Schedule 1, measured in gigajoules per cubic metre.

EF_k is the emission factor for the methane (***k***) within the fuel type from the mine during the year, measured in kilograms of CO_2-e per gigajoule, estimated in accordance with Division 2.3.3.

OF_i is 0.98, which is the destruction efficiency of coal mine waste gas (***i***) flared.

Q_k is the quantity of methane (***k***) within the fuel type from the mine during the year, measured in cubic metres in accordance with Division 2.3.6.

QCO_2 is the quantity of carbon dioxide within the coal mine waste gas emitted from the mine during the year, measured in CO_2-e tonnes in accordance with Division 2.3.3.

3.15A Method 2—emissions of methane and nitrous oxide from coal mine waste gas flared

For subparagraphs 3.4(4)(b)(ii) and (c)(ii), method 2 is:

$$E_{ij} = \frac{Q_k \times EC_i \times EF_{kj}}{1000} \times OF_i$$

where:

E_{ij} is the emissions of gas type (***j***), being methane or nitrous oxide, released from coal mine waste gas (***i***) flared from the mine during the year, measured in CO_2-e tonnes.

EC_i is the energy content factor of methane (***k***) within coal mine waste gas (***i***) mentioned in item 19 of Schedule 1, measured in gigajoules per cubic metre.

EF_{kj} is the emission factor of gas type (***j***), being methane or nitrous oxide, for the quantity of methane (***k***) within coal mine waste gas (***i***) flared, mentioned in item 19 of Schedule 1 and measured in kilograms of CO_2-e per gigajoule.

OF_i is 0.98, which is the destruction efficiency of coal mine waste gas (***i***) flared.

Q_k is the quantity of methane (***k***) within the coal mine waste gas (***i***) flared from the mine during the year, measured in cubic metres in accordance with Division 2.3.3.

3.16 Method 3—coal mine waste gas flared

(1) For subparagraph 3.4(4)(a)(iii), method 3 is the same as method 2 under section 3.15.

(2) In applying method 2 under section 3.15, the facility specific emission factor $\boldsymbol{EF_k}$ must be determined in accordance with the procedure for determining $\boldsymbol{EF_{iCO_2oxec}}$ in Division 2.3.4.

Subdivision 3.2.2.4—Fugitive emissions from post-mining activities

3.17 Method 1—post-mining activities related to gassy mines

(1) For subsection 3.4(6), method 1 is the same as method 1 under section 3.5.

(2) In applying method 1 under section 3.5, $\boldsymbol{EF_j}$ is taken to be 0.017, which is the emission factor for methane (***j***), measured in CO_2-e tonnes per tonne of run-of-mine coal extracted from the mine.

Division 3.2.3—Open cut mines

Subdivision 3.2.3.1—Preliminary

3.18 Application

This Division applies to fugitive emissions from open cut mining activities.

3.19 Available methods

(1) Subject to section 1.18, for estimating emissions released during a year from the operation of a facility that is constituted by an open cut mine the methods as set out in this section must be used.

Methane from extraction of coal

(2) Subject to subsection (7), one of the following methods must be used for estimating fugitive emissions of methane that result from the extraction of coal from the mine:

- (a) method 1 under section 3.20;
- (b) method 2 under section 3.21;
- (c) method 3 under section 3.26.

Note: There is no method 4 for subsection (2).

Carbon dioxide from extraction of coal

(3) If method 2 under section 3.21 is used under subsection (2), that method must be used for estimating fugitive emissions of carbon dioxide that result from the extraction of coal from the open cut mine.

(4) If method 3 under section 3.26 is used under subsection (2), that method must be used for estimating fugitive emissions of carbon dioxide that result from the extraction of coal from the open cut mine.

Note: There is no method 1 or 4 for estimating fugitive emissions of carbon dioxide that result from the extraction of coal from an open cut mine.

Flaring

(5) For estimating emissions released from coal mine waste gas flared from the open cut mine:

- (a) one of the following methods must be used for estimating emissions of carbon dioxide released:
  - (i) method 1 under section 3.27;
  - (ii) method 2 under section 3.28;
  - (iii) method 3 under section 3.29; and
- (b) method 1 under section 3.27 must be used for estimating emissions of methane released; and

(c) method 1 under section 3.27 must be used for estimating emissions of nitrous oxide released.

Note: The flaring of coal mine waste gas releases emissions of carbon dioxide, methane and nitrous oxide. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide, no method 2, 3 or 4 for emissions of methane and no method 2, 3 or 4 for emissions of nitrous oxide.

Venting or other fugitive release before extraction of coal

(6) Method 4 under Part 1.3 must be used for estimating fugitive emissions of each gas type, being carbon dioxide and methane, that result from venting or other fugitive release of gas from the mine before coal is extracted from the mine.

Note: There is no method 1, 2 or 3 for subsection (6).

(7) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

Subdivision 3.2.3.2—Fugitive emissions from extraction of coal

3.20 Method 1—extraction of coal

For paragraph 3.19(2)(a), method 1 is:

$$E_j = Q \times EF_j$$

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 CO_2-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 CO_2-e tonnes per tonne of run-of-mine coal extracted from the mine, taken to be the following:

(a) for a mine in New South Wales—0.054;
(b) for a mine in Victoria—0.00027;
(c) for a mine in Queensland—0.020;
(d) for a mine in Western Australia—0.020;
(e) for a mine in South Australia—0.00027;
(f) for a mine in Tasmania—0.017.

3.21 Method 2—extraction of coal

(1) For paragraph 3.19(2)(b) and subsection 3.19(3), method 2 is:

$$E_j = \gamma_j \; \Sigma_z \left(S_{j,z}\right)$$

where:

E_j is the fugitive emissions of gas type (*j*) that result from the extraction of coal from the mine during the year, measured in CO_2-e tonnes.

γ_j is the factor for converting a quantity of gas type (*j*) from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes, as follows:

(a) for methane—$6.784 \times 10^{-4} \times 25$;
(b) for carbon dioxide—1.861×10^{-3}.

$\sum_z (S_{j,z})$ is the total of gas type (*j*) in all gas bearing strata (*z*) under the extraction area of the mine during the year, measured in cubic metres, where the gas in each strata is estimated under section 3.22.

(2) Method 2 requires each gas in a gas bearing strata to be sampled and analysed in accordance with the requirements in sections 3.24, 3.25 and 3.25A.

3.22 Total gas contained by gas bearing strata

(1) For method 2 under subsection 3.21(1), $S_{j,z}$ for gas type (*j*) contained in a gas bearing strata (*z*) under the extraction area of the mine during the year, measured in cubic metres, is:

$$S_{jz} = M_z \times \beta_z \times GC_{jz} - \sum_t Q_{ij,\,cap,z} - \sum_t Q_{ij,flared,z} - \sum_t Q_{ijtr} - \sum_t E_{j,vented,z}$$

where:

M_z is the mass of the gas bearing strata (*z*) under the extraction area of the mine during the year, measured in tonnes.

β_z is the proportion of the gas content of the gas bearing strata (*z*) that is released by extracting coal from the extraction area of the mine during the year, as follows:

(a) if the gas bearing strata is at or above the pit floor—1;
(b) in any other case—as estimated under section 3.23.

GC_{jz} is the content of gas type (*j*) contained by the gas bearing strata (*z*) before gas capture, flaring or venting is undertaken at the extraction area of the mine during the year, measured in cubic metres per tonne of gas bearing strata at standard conditions.

$\sum Q_{ij,cap,z}$ is the total quantity of gas type (*j*) in coal mine waste gas (*i*) captured for combustion from the gas bearing strata (*z*) at any time before coal is extracted from the extraction area of the mine during the year, measured in cubic metres.

$\sum Q_{ij,flared,z}$ is the total quantity of gas type (*j*) in coal mine waste gas (*i*) flared from the gas bearing strata (*z*) at any time before coal is extracted from the extraction area of the mine during the year, measured in cubic metres.

$\sum Q_{ijtr}$ is the total quantity of gas type (*j*) in coal mine waste gas (*i*) transferred out of the mining activities at any time before coal is extracted from the extraction area of the mine during the year, measured in cubic metres.

$\sum \boldsymbol{E_{j,vented,z}}$ is the total emissions of gas type (***j***) vented from the gas bearing strata (***z***) at any time before coal is extracted from the extraction area of the mine during the year, measured in cubic metres and estimated under subsection 3.19 (6).

(2) For $\sum \boldsymbol{Q_{ij,cap,z}}$, $\sum \boldsymbol{Q_{ij,flared,z}}$ and $\sum \boldsymbol{Q_{ijtr}}$ in subsection (1), the quantity of gas type (***j***) must be estimated in accordance with Division 2.3.6 as if a reference in that Division to quantities of gaseous fuels combusted from the operation of a facility was a reference to the following:

(a) for $\sum \boldsymbol{Q_{ij,cap,z}}$—quantities of gaseous fuels captured from the operation of a facility;

(b) for $\sum_t \boldsymbol{Q_{ij,flared,z}}$—quantities of gaseous fuels flared from the operation of a facility;

(c) for $\sum \boldsymbol{Q_{ijtr}}$—quantities of gaseous fuels transferred out of the operation of a facility.

(3) In subsection (1), $\sum Q_{ijtr}$ applies to carbon dioxide only if the carbon dioxide is captured for permanent storage.

Note: Division 1.2.3 contains a number of requirements in relation to deductions of carbon dioxide captured for permanent storage.

(4) For $\boldsymbol{GC_{jz}}$ in subsection (1), the content of gas type (***j***) contained by the gas bearing strata (***z***) must be estimated in accordance with sections 3.24, 3.25, 3.25A and 3.25B.

3.23 Estimate of proportion of gas content released below pit floor

For paragraph (b) of the factor $\boldsymbol{\beta_z}$ in subsection 3.22(1), estimate $\boldsymbol{\beta_z}$ using one of the following equations:

(a) equation 1:

$$\beta_z = 1 - \frac{x - h}{dh};$$

(b) equation 2:

$$\beta_z = 0.5.$$

where:

x is the depth in metres of the floor of the gas bearing strata (***z***) measured from ground level.

h is the depth in metres of the pit floor of the mine measured from ground level.

dh is 20, being representative of the depth in metres of the gas bearing strata below the pit floor that releases gas.

3.24 General requirements for sampling

(1) Core samples of a gas bearing strata must be collected to produce estimates of gas content that are representative of the gas bearing strata in the extraction area of the mine during the year.

(2) The sampling process must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(3) Bias must be tested in accordance with an appropriate standard (if any).

(4) The value obtained from the samples must only be used for the open cut mine from which it was intended to be representative.

(5) Sampling must be carried out in accordance with:
  (a) the minimum requirements for data collection and gas testing mentioned in section 2 of the ACARP Guidelines; and
  (b) the data validation, analysis and interpretation processes mentioned in section 3 of the ACARP Guidelines.

3.25 General requirements for analysis of gas and gas bearing strata

Analysis of a gas and a gas bearing strata, including the mass and gas content of the strata, must be done in accordance with:
  (a) the minimum requirements for data collection and gas testing mentioned in section 2 of the ACARP Guidelines; and
  (b) the data validation, analysis and interpretation processes mentioned in section 3 of the ACARP Guidelines; and
  (c) the method of applying the gas distribution model to develop an emissions estimate for an open cut mine mentioned in section 4 of the ACARP Guidelines.

3.25A Method of working out base of the low gas zone

(1) The estimator must:
  (a) take all reasonable steps to ensure that samples of gas taken from the gas bearing strata of the open cut mine are taken in accordance with the minimum requirements for data collection and gas testing mentioned in section 2 of the ACARP Guidelines; and
  (b) take all reasonable steps to ensure that samples of gas taken from boreholes are taken in accordance with the requirements for:
    (i) the number of boreholes mentioned in sections 2 and 3 of the ACARP Guidelines; and
    (ii) borehole spacing mentioned in section 2 of the ACARP Guidelines; and
    (iii) sample selection mentioned in section 2 of the ACARP Guidelines; and
  (c) work out the base of the low gas zone by using the method mentioned in subsection (2); and

(d) if the base of the low gas zone worked out in accordance with subsection (2) varies, in a vertical plane, within:
  (i) a range of 20 metres between boreholes located in the same domain of the open cut mine—work out the base of the low gas zone using the method mentioned in subsection (3); or
  (ii) a range of greater than 20 metres between boreholes located in the same domain of the open cut mine—the method mentioned in subsection (4).

Preliminary method of working out base of low gas zone

(2) For paragraph (1)(c), the method is that the estimator must perform the following steps:

Step 1 For each borehole, identify the depth at which:
  (a) the results of greater than 3 consecutive samples taken in the borehole indicate that the gas content of the gas bearing strata is greater than 0.5 m^3/t; or
  (b) the results of 3 consecutive samples taken in the borehole indicate that the methane composition of the gas bearing strata is greater than 50% of total gas composition by volume.

Step 2 If paragraph (a) or (b) of step 1 applies, identify, for each borehole, the depth of the top of the gas bearing strata at which the first of the 3 consecutive samples in the borehole was taken.

Note The depth of the top of the gas bearing strata worked out under step 2 is the same as the depth of the base of the low gas zone.

Method of working out base of low gas zone for subparagraph (1)(d)(i)

(3) For subparagraph (1)(d)(i), the method is that the estimator must work out the average depth at which step 2 of the method in subsection (2) applies.

Method of working out base of low gas zone for subparagraph (1)(d)(ii)

(4) For subparagraph (1)(d)(ii), the method is that the estimator must construct a 3-dimensional model of the surface of the low gas zone using a triangulation algorithm or a gridding algorithm.

3.25B Further requirements for estimator

(1) This section applies if:
  (a) the estimator constructs a 3-dimensional model of the surface of the base of the low gas zone in accordance with the method mentioned in subsection 3.25A(4); and
  (b) the 3-dimensional model of the surface of the low gas zone is extrapolated beyond the area modelled directly from boreholes in the domain.

(2) The estimator must:
  (a) ensure that the extrapolated surface:

- (i) applies the same geological modelling rules that were applied in the generation of the surface of the base of the low gas zone from the boreholes; and
- (ii) represents the base of the low gas zone in relation to the geological structures located within the domain; and
- (iii) is generated using a modelling methodology that is consistent with the geological model used to estimate the coal resource; and
- (iv) the geological model used to estimate the coal resource meets the minimum requirements and the standard of quality mentioned in section 1 of the ACARP Guidelines.

(b) make and retain a record:
- (i) of the data and assumptions incorporated into the generation of the 3-dimensional surface; and
- (ii) that demonstrates that the delineation of the 3-dimensional surface complies with sections 1.13 and 3.24.

3.25C Default gas content for gas bearing strata in low gas zone

A default gas content of 0.00023 tonnes of carbon dioxide per tonne of gas bearing strata must be assigned to all gas bearing strata located in the low gas zone.

3.25D Requirements for estimating total gas contained in gas bearing strata

(1) The total gas contained in gas bearing strata for an open cut coal mine must be estimated in accordance with the emissions estimation process mentioned in section 1 of the ACARP Guidelines.

(2) The gas distribution model used for estimating emissions must be applied in accordance with section 4.1 of the ACARP Guidelines; and

(3) The modelling bias must be assessed in accordance with section 4.2 of the ACARP Guidelines.

(4) The gas distribution model must be applied to the geology model in accordance with section 4.3 of the ACARP Guidelines.

3.26 Method 3—extraction of coal

(1) For paragraph 3.19(2)(c) and subsection 3.19(4), method 3 is the same as method 2 under section 3.21

(2) In applying method 2 under section 3.21 a sample of gas bearing strata must be collected in accordance with an appropriate standard, including:
- (a) AS 2617—1996 *Sampling from coal seams* or an equivalent standard; and
- (b) AS 2519—1993 *Guide to the technical evaluation of higher rank coal deposits* or an equivalent standard.

Subdivision 3.2.3.3—Emissions released from coal mine waste gas flared

3.27 Method 1—coal mine waste gas flared

(1) For subparagraph 3.19(5)(a)(i) and paragraph 3.19(5)(b) and paragraph (5)(c), method 1 is the same as method 1 under section 3.14.

(2) In applying method 1 under section 3.14, a reference to an underground mine is taken to be a reference to an open cut mine.

3.28 Method 2—coal mine waste gas flared

For subparagraph 3.19(5)(a)(ii), method 2 is the same as method 2 under section 3.15.

3.29 Method 3—coal mine waste gas flared

For subparagraph 3.19(5)(a)(iii), method 3 is the same as method 3 under section 3.16.

Division 3.2.4—Decommissioned underground mines

Subdivision 3.2.4.1—Preliminary

3.30 Application

This Division applies to fugitive emissions from decommissioned underground mines from the time that they became a decommissioned underground coal mine, other than mines which have been a decommissioned underground coal mine for a continuous period of 20 years or more.

3.31 Available methods

(1) Subject to sections 1.18 and 3.30, for estimating emissions released during a year from the operation of a facility that is constituted by a decommissioned underground mine the methods as set out in this section must be used.

Methane from decommissioned mines

(2) One of the following methods must be used for estimating fugitive emissions of methane that result from the mine:
  (a) subject to subsection (6), method 1 under section 3.32;
  (b) method 4 under section 3.37.

Note: There is no method 2 or 3 for subsection (2).

Carbon dioxide from decommissioned mines

(3) If method 4 under section 3.37 is used under subsection (2), that method must be used for estimating fugitive emissions of carbon dioxide that result from the mine.

Note: There is no method 1, 2 or 3 for subsection (3).

Flaring

(4) For estimating emissions released from coal mine waste gas flared from the mine:
  (a) one of the following methods must be used for estimating emissions of carbon dioxide released:
    (i) method 1 under section 3.38;
    (ii) method 2 under section 3.39;
    (iii) method 3 under section 3.40; and
  (b) method 1 under section 3.38 must be used for estimating emissions of methane released.
  (c) method 1 under section 3.38 must be used for estimating emissions of nitrous oxide released.

Note: The flaring of coal mine waste gas releases emissions of carbon dioxide, methane and nitrous oxide. The same formula is used to estimate emissions of each of these gases.

There is no method 4 for emissions of carbon dioxide, no method 2, 3 or 4 for emissions of methane and no method 2, 3 or 4 for nitrous oxide.

(5) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

(6) If coal mine waste gas from the decommissioned underground mine is captured during the year, method 1 in subsection (2) must not be used.

Subdivision 3.2.4.2—Fugitive emissions from decommissioned underground mines

3.32 Method 1—decommissioned underground mines

(1) For paragraph 3.31(2)(a), method 1 is:

$$E_{dm} = [E_{tdm} \times EF_{dm} \times (1 - F_{dm})]$$

where:

E

E_{dm} is the fugitive emissions of methane from the mine during the year measured in CO_2-e tonnes.

E_{tdm} is the emissions from the mine for the last 12 month period before the mine became a decommissioned underground coal mine, measured in CO_2-e tonnes and estimated under section 3.6.

EF_{dm} is the emission factor for the mine calculated under section 3.33.

F_{dm} is the proportion of the mine flooded at the end of the year, as estimated under section 3.34, and must not be greater than 1.

(2) However, if, under subsection (1), the estimated emissions in CO_2-e tonnes for the mine during the year is less than $0.02 \times E_{tdm}$, the estimated emissions for the mine during the year is taken to be $0.02 \times E_{tdm}$.

3.33 Emission factor for decommissioned underground mines

For section 3.32, EF_{dm} is the integral under the curve of:

$$(1 + A \times T)^b - C$$

for the period between ***T*** and ***T-N***,
where:

A is:

(a) for a gassy mine—$\frac{0.23}{12}$; or

(b) for a non-gassy mine—$\frac{0.35}{12}$.

T is the number of whole months since the mine became a decommissioned underground coal mine, at the end of the reporting year.

N is:

- (a) if ***T*** is less than 12—the value for ***T***; or
- (b) if ***T*** is 12 or greater—12.

b is:

- (a) for a gassy mine—-1.45; or
- (b) for a non-gassy mine—-1.01.

C is:

- (a) for a gassy mine—0.024; or
- (b) for a non-gassy mine—0.088.

3.34 Measurement of proportion of mine that is flooded

For subsection 3.32(1), $\boldsymbol{F_{dm}}$ is:

$$\frac{M_{WI}}{M_{VV}} \times \frac{months}{12}$$

where:

$\boldsymbol{M_{WI}}$ is the rate of water flow into the mine in cubic metres per year as measured under section 3.35.

$\boldsymbol{M_{VV}}$ is the mine void volume in cubic metres as measured under section 3.36.

months is the number of whole months since the mine became a decommissioned underground coal mine, at the end of the reporting year.

3.35 Water flow into mine

For $\boldsymbol{M_{WI}}$ in section 3.34, the rate of water flow into the mine must be measured by:

- (a) using water flow rates for the mine estimated in accordance with an appropriate standard; or
- (b) using the following average water flow rates:
  - (i) for a mine in the southern coalfield of New South Wales—913 000 cubic metres per year; or
  - (ii) for a mine in the Newcastle, Hunter, Western or Gunnedah coalfields in New South Wales—450 000 cubic metres per year; or
  - (iii) for a mine in Queensland—74 000 cubic metres per year.

Note: An appropriate standard includes AS 2519—1993 *Guide to the technical evaluation of higher rank coal deposits*.

3.36 Size of mine void volume

For $\boldsymbol{M_{VV}}$ in section 3.34, the size of the mine void volume must be measured by:

- (a) using mine void volumes for the mine estimated in accordance with industry practice; or

(b) dividing the total amount of run-of-mine coal extracted from the mine before the mine was decommissioned by 1.425.

3.37 Method 4—decommissioned underground mines

(1) For paragraph 3.31(2)(b) and subsection 3.31(3), method 4 is the same as method 4 in section 3.6.

(2) In applying method 4 under section 3.6, a reference to an underground mine is taken to be a reference to a decommissioned underground mine.

Subdivision 3.2.4.3—Fugitive emissions from coal mine waste gas flared

3.38 Method 1—coal mine waste gas flared

(1) For subparagraph 3.31(4)(a)(i) and paragraphs 3.31(4)(b) and (4)(c), method 1 is the same as method 1 under section 3.14.

(2) In applying method 1 under section 3.14, a reference to an underground mine is taken to be a reference to a decommissioned underground mine.

3.39 Method 2—coal mine waste gas flared

For subparagraph 3.31(4)(a)(ii), method 2 is the same as method 2 under section 3.15.

3.40 Method 3—coal mine waste gas flared

For subparagraph 3.31(4)(a)(iii), method 3 is the same as method 3 under section 3.16.

Part 3.3—Oil and natural gas—fugitive emissions

Division 3.3.1—Preliminary

3.40A Definition of *natural gas* for Part 3.3

In this Part:

natural gas includes the following:

(a) shale gas;
(b) tight gas;
(c) coal seam methane.

3.41 Outline of Part

This Part provides for fugitive emissions from the following:

(a) oil or gas exploration (see Division 3.3.2);
(b) crude oil production (see Division 3.3.3);
(c) crude oil transport (see Division 3.3.4);
(d) crude oil refining (see Division 3.3.5);
(e) natural gas production or processing, other than emissions that are vented or flared (see Division 3.3.6);
(f) natural gas transmission (see Division 3.3.7);
(g) natural gas distribution (see Division 3.3.8);
(h) natural gas production or processing (emissions that are vented or flared) (see Division 3.3.9).

Division 3.3.2—Oil or gas exploration

Subdivision 3.3.2.1—Preliminary

3.42 Application

This Division applies to fugitive emissions from venting or flaring from oil or gas exploration activities, including emissions from:

(a) oil well drilling; and
(b) gas well drilling; and
(c) drill stem testing; and
(d) well completions; and
(e) wellworkovers.

Subdivision 3.3.2.2—Oil or gas exploration (flared) emissions

3.43 Available methods

(1) Subject to section 1.18, for estimating emissions released by oil or gas flaring during the year from the operation of a facility that is constituted by oil or gas exploration:

(a) if estimating emissions of carbon dioxide released—one of the following methods must be used:
  (i) method 1 under section 3.44;
  (ii) method 2 under section 3.45;
  (iii) method 3 under section 3.46; and
(b) if estimating emissions of methane released—one of the following methods must be used:
  (i) method 1 under section 3.44;
  (ii) method 2A under section 3.45A; and
(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:
  (i) method 1 under section 3.44;
  (ii) method 2A under section 3.45A.

Note: There is no method 4 under paragraph (a) and no method 2, 3 or 4 under paragraph (b) or (c).

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.44 Method 1—oil or gas exploration

(1) Method 1 is:

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

where:

E_{ij} is the fugitive emissions of gas type (***j***) from a fuel type (***i***) flared in the oil or gas exploration during the year measured in CO_2-e tonnes.

Q_i is the quantity of fuel type (***i***) flared in the oil or gas exploration during the year measured in tonnes.

EF_{ij} is the emission factor for gas type (***j***) measured in tonnes of CO_2-e emissions per tonne of the fuel type (***i***) flared.

(2) For EF_{ij} in subsection (1), columns 3, 4 and 5 of an item in the following table specify the emission factor, for gas type (***j***), for each fuel type (***i***) specified in column 2 of that item.

Item	**Fuel type (*i*)**	**Emission factor for gas type (*j*) (tonnes CO_2-e/tonnes of fuel flared)**		
		CO_2	**CH_4**	**N_2O**
1	Unprocessed gas flared	2.8	0.8	0.03
2	Crude oil	3.2	0.008	0.07

3.45 Method 2—oil or gas exploration (flared carbon dioxide emissions)

Combustion of gaseous fuels (flared) emissions

(1) For subparagraph 3.43(1)(a)(ii), method 2 for combustion of gaseous fuels is:

$$E_{ico_2} = Q_h \times EF_h \times OF_i + QCO_2$$

where:

E_{iCO_2} is the fugitive emissions of CO_2 from fuel type (***i***) flared in oil or gas exploration during the year, measured in CO_2-e tonnes.

Q_h is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in oil or gas exploration during the year, measured in tonnes in accordance with Division 2.3.3.

EF_h is the emission factor for the total hydrocarbons (***h***) within the fuel type (***i***) in oil or gas exploration during the year, measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared, estimated in accordance with Division 2.3.3.

OF_i is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

QCO_2 is the quantity of CO_2 within fuel type (***i***) in oil or gas exploration during the year, measured in CO_2-e tonnes in accordance with Division 2.3.3.

Combustion of liquid fuels (flared) emissions

(2) For subparagraph 3.43(1)(a)(ii), method 2 for combustion of liquid fuels is the same as method 1 under section 3.44, but the carbon dioxide emissions factor EF_{ij} must be determined in accordance with method 2 in Division 2.4.3.

3.45A Method 2A—oil or gas exploration (flared methane or nitrous oxide emissions)

For subparagraphs 3.43(1)(b)(ii) and (c)(ii), method 2A is:

$$E_{ij} = Q_h \times EF_{hij} \times OF_i$$

where:

EF_{hij} is the emission factor of gas type (***j***), being methane or nitrous oxide, for the total hydrocarbons (***h***) within the fuel type (***i***) in oil or gas exploration during the year, mentioned for the fuel type in the table in subsection 3.44(2) and measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared.

E_{ij} is the fugitive emissions of gas type (***j***), being methane or nitrous oxide, from fuel type (***i***) flared from oil or gas exploration during the year, measured in CO_2-e tonnes.

OF_i is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

Q_h is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in oil or gas exploration during the year, measured in tonnes in accordance with Division 2.3.3 for gaseous fuels or Division 2.4.3 for liquid fuels.

3.46 Method 3—oil or gas exploration

Combustion of gaseous fuels (flared) emissions

(1) For subparagraph 3.43(1)(a)(iii), method 3 for the combustion of gaseous fuels is the same as method 2, but the carbon dioxide emissions factor EF_h must be determined in accordance with method 3 in Division 2.3.4.

Combustion of liquid fuels (flared) emissions

(2) For subparagraph 3.43(1)(a)(iii), method 3 for the combustion of liquid fuels is the same as method 2, but the carbon dioxide emissions factor EF_h must be determined in accordance with method 3 in Division 2.4.4.

Subdivision 3.3.2.3—Oil or gas exploration—fugitive emissions from system upsets, accidents and deliberate releases from process vents

3.46A Available methods

(1) Subject to section 1.18, the methods mentioned in subsections (2) and (3) must be used for estimating fugitive emissions that result from system upsets, accidents and deliberate releases from process vents during a reporting year from the operation of a facility that is constituted by oil or gas exploration.

(2) To estimate emissions that result from deliberate releases from process vents, systems upsets and accidents at a facility during a year, for each oil or gas exploration activity one of the following methods must be used:
- (a) method 1 under section 3.84;
- (b) method 4 under:
  - (i) for emissions of methane and carbon dioxide from natural gas well completions or well workover activities—section 3.46B; or
  - (ii) for emissions and activities not mentioned in subparagraph (i)—Part 1.3.

(3) For estimating incidental emissions that result from deliberate releases from process vents, system upsets and accidents during a year from the operation of the facility, another method may be used that is consistent with the principles mentioned in section 1.13.

Note: There is no method 2 or 3 for this Subdivision.

3.46B Method 4—vented emissions from well completions and well workovers

Vented volume measured for all wells and well types in a basin

(1) For subparagraph 3.46A(2)(b)(i), where vented volume is measured for all wells and well types (horizontal or vertical) in a basin, method 4 is:

$$\text{Em}_j = \gamma_j \times \left[\sum_{p=1}^{W} \text{ES}_p + \left(\sum_{j=1}^{Z} \text{VIGG}_{j,p} \right) \right]$$

where:

Em_j is total emissions for gas type (***j***), being methane and carbon dioxide from all well completions and well workovers during a year in a basin, measured in CO_2-e tonnes.

ES_p is the volume of methane vented during a well completion or well workover from strata for each well (***p***) in cubic metres at standard conditions, worked out in accordance with subsection (2).

$VIGG_{j,p}$ is the volume of gas type (***j***) in cubic metres at standard conditions, being methane and carbon dioxide, injected into the well during well completion or well workover, worked out in accordance with subsection (3).

W is the total number of well completions and well workovers in the basin during a year.

γ_j is the factor for converting a quantity of gas type (***j***) from cubic metres at standard conditions to CO_2-e tonnes, being:

(a) for methane—$6.784 \times 10^{-4} \times 25$; and

(b) for carbon dioxide—1.861×10^{-3}.

Z is the total number of greenhouse gas types.

(2) For subsection (1), the factor ES_p is worked out using the formula:

$$FV_p - VI_p$$

where:

FV_p is the flow volume of each well (***p***) in cubic metres at standard conditions, measured using a digital or analog recording flow metre on the vent line to measure flowback during the well completion or well workover, estimated in accordance with Division 2.3.6.

VI_p is the volume of injected gas in cubic metres at standard conditions that is injected into the well during the well completion or well workover, estimated in accordance with Division 2.3.6.

(3) For subsection (1), $VIGG_{j,p}$ is worked out using the following formula:

$$VI_p \times mol_{j,p}\%$$

where:

$mol_{j,p}\%$, for each gas type (***j***), being methane and carbon dioxide, is the gas type's share of one mole of VI_p expressed as a percentage, estimated in accordance with Division 2.3.3.

VI_p is the volume of injected gas in cubic metres at standard conditions that is injected into the well during the well completion or well workover, estimated in accordance with Division 2.3.6.

Vented volume measured for a sample of wells and well types in a basin

(4) For subparagraph 3.46A(2)(b)(i), where vented volume is measured for a sample of wells and well types (horizontal or vertical) in a basin, method 4 is:

$$Em_j = \gamma_j \times \left[\sum_{p=1}^{W} EV_p + \sum_{j=1}^{Z}\left(VIGG_{j,p} - SG_{j,p}\right)\right]$$

where:

Em_j is total emissions for gas type (***j***), being methane and carbon dioxide from all well completions and well workovers during a year in a basin, measured in CO_2-e tonnes.

EV_p is the volume of methane flowback during a well completion or well workover from strata for each well (***p***) in cubic metres at standard conditions, worked out in accordance with subsection (5).

$SG_{j,p}$ is the volume of gas type (***j***), being methane and carbon dioxide, in cubic metres at standard conditions that is captured or flared for each well (***p***) during the well completion or well workover, estimated in accordance with:

(a) for the volume of the gas—Division 2.3.6; and

(b) for the gas composition—Division 2.3.3.

$VIGG_{j,p}$ is the volume of gas type (***j***), being methane and carbon dioxide, injected into each well (***p***) during the well completion or well workover, worked out in accordance with subsection (6).

W is the total number of well completions and well workovers during a year in the basin.

γ_j is the factor for converting a quantity of gas type (***j***) from cubic metres at standard conditions to CO_2-e tonnes, being:

(a) for methane—$6.784 \times 10^{-4} \times 25$; and

(b) for carbon dioxide—1.861×10^{-3}.

Z is the total number of greenhouse gas types.

(5) For subsection (4), the factor EV_p is worked out using the following formula:

$$T_p \times FRM_{bt} \times PR_p - VI_p$$

where:

FRM_{bt} is the ratio of flowback during well completions and well workovers to the 30 day production rate for the basin (***b***) and the well type combination (***t***), as worked out in accordance with subsection (7).

PR_p is the first 30 days average production flow rate in cubic metres per hour at each well (***p***), estimated in accordance with Division 2.3.6.

T_p is the total number of hours for the reporting year of flowback for the well completion or well workover for each well (***p***) and well type (horizontal or vertical) in a basin.

VI_p is the volume of injected gas in cubic metres at standard conditions that is injected into the well during the well completion or well workover, estimated in accordance with Division 2.3.6.

(6) For subsection (4), $VIGG_{j,p}$ is worked out using the following formula:

$$VI_p \times mol_{j,p}\%$$

where:

$mol_{j,p}\%$, for each gas type (***j***), being methane and carbon dioxide, is the gas type's share of one mole of VI_p expressed as a percentage, estimated in accordance with Division 2.3.6.

VI_p is the volume of injected gas in cubic metres at standard conditions that is injected into the well during the well completion or well workover, estimated in accordance with Division 2.3.6.

(7) For subsection (5), the factor $\boldsymbol{FRM_{bt}}$ is worked out using the following formula:

$$\frac{\sum_{p=1}^{N} FR_{p(bt)}}{\sum_{p=1}^{N} PR_{p(bt)}}$$

where:

$\boldsymbol{FR_{p(bt)}}$ is the average flow rate for flowback during well completions and well workovers in cubic metres per hour at standard conditions for each basin (***b***) and well type combination (***t***), determined using a digital or analog recording flow metre on the vent line to measure flowback during the well completion or well workover, estimated in accordance with Division 2.3.6.

N is the number of measured well completions or well workovers in the basin.

$\boldsymbol{PR_{p(bt)}}$ is the first 30 days production flow rate in cubic metres per hour for each well (***p***) and well type (***t***) measured in a basin (***b***), estimated in accordance with Division 2.3.6.

(8) For subsection (7), the sampling requirements for the number of well completions or well workovers performed during a year for each basin and well type (horizontal or vertical) are as follows:

(a) if one to 5 well completions or workovers are performed during a year, all wells are to be measured;

(b) if 6 to 50 well completions or workovers are performed during a year, a minimum of 5 wells are to be measured;

(c) if more than 50 well completions or workovers are performed during a year, a minimum of 10% of wells are to be measured.

Division 3.3.3—Crude oil production

Subdivision 3.3.3.1—Preliminary

3.47 Application

(1) This Division applies to fugitive emissions from crude oil production activities, including emissions from flaring, from:

(a) an oil wellhead; and

(b) well servicing; and

(c) oil sands mining; and

(d) shale oil mining; and

(e) the transportation of untreated production to treating or extraction plants; and

(f) activities at extraction plants or heavy oil upgrading plants, and gas reinjection systems and produced water disposal systems associated with the those plants; and

(g) activities at upgrading plants and associated gas reinjection systems and produced water disposal systems.

(2) For paragraph (1)(e), ***untreated production*** includes:

(a) well effluent; and

(b) emulsion; and

(c) oil shale; and

(d) oil sands.

Subdivision 3.3.3.2—Crude oil production (non-flared)—fugitive leak emissions of methane

3.48 Available methods

(1) Subject to section 1.18, for estimating fugitive emissions of methane, other than fugitive emissions of methane specified in subsection (1A), during a year from the operation of a facility that is constituted by crude oil production, one of the following methods must be used:

(a) method 1 under section 3.49;

(b) method 2 under section 3.50;

Note: There is no method 3 or 4 for this Division.

(1A) For subsection (1), the following fugitive emissions of methane are specified:

(a) fugitive emissions from oil or gas flaring;

(b) fugitive emissions that result from system upsets, accidents or deliberate releases from process vents.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.49 Method 1—crude oil production (non-flared) emissions of methane

(1) Method 1 is:

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

where:

E_{ij} is the fugitive emissions of methane (***j***) from the crude oil production during the year measured in CO_2-e tonnes.

Σ_k is the emissions of methane (***j***) measured in tonnes of CO_2-e and estimated by summing up the emissions released from all of the equipment of type (***k***) specified in column 2 of the table in subsection (2), if the equipment is used in the crude oil production.

Q_{ik} is the total of the quantities of crude oil measured in tonnes that pass through each equipment of type (***k***) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the crude oil production.

EF_{ijk} is the emission factor for methane (***j***) measured in tonnes of CO_2-e per tonne of crude oil that passes through each equipment of type (***k***) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the crude oil production.

Q_i is the total quantity of crude oil (***i***) measured in tonnes that passes through the crude oil production.

$EF_{(l)\ ij}$ is 1.4×10^{-3}, which is the emission factor for methane (***j***) from general leaks in the crude oil production, measured in CO_2-e tonnes per tonne of crude oil that passes through the crude oil production.

(2) For EF_{ijk} mentioned in subsection (1), column 3 of an item in the following table specifies the emission factor for an equipment of type (***k***) specified in column 2 of that item:

Item	**Equipment type (k)**	**Emission factor for gas type (j) (tonnes CO_2-e/tonnes fuel throughput)**
		CH_4
1	Internal floating tank	1.0×10^{-6}
2	Fixed roof tank	5.0×10^{-6}
3	Floating tank	4.0×10^{-6}

(3) For $EF_{(l)\ ij}$ in subsection (1), general leaks in the crude oil production comprise the emissions (other than vent emissions) from equipment listed in sections 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil production.

3.50 Method 2—crude oil production (non-flared) emissions of methane

(1) Method 2 is:

$$E_{ij} = \Sigma_k (Q_{ik} \times EF_{ijk})$$

where:

E_{ij} is the fugitive emissions of methane (***j***) from the crude oil production during the year measured in CO_2-e tonnes.

Σ_k is the emissions of methane (***j***) measured in tonnes of CO_2-e and estimated by summing up the emissions released from each equipment type (***k***) listed in sections 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, if the equipment type is used in the crude oil production.

Q_{ik} is the total of the quantities of crude oil that pass through each equipment type (***k***), or the number of equipment units of type (***k***), listed in sections 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil production, measured in tonnes.

EF_{ijk} is the emission factor of methane (***j***) measured in tonnes of CO_2-e per tonne of crude oil that passes through each equipment type (***k***) listed in sections 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil production.

(2) For ***EF_{ijk}***, the emission factors for methane (***j***), as crude oil passes through an equipment type (***k***), are:
   (a) as listed in sections 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, for the equipment type; or
   (b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors.

Subdivision 3.3.3.3—Crude oil production (flared)—fugitive emissions of carbon dioxide, methane and nitrous oxide

3.51 Available methods

(1) Subject to section 1.18, for estimating emissions released by oil or gas flaring during a year from the operation of a facility that is constituted by crude oil production:
   (a) if estimating emissions of carbon dioxide released—one of the following methods must be used:
      (i) method 1 under section 3.52;
      (ii) method 2 under section 3.53;
      (iii) method 3 under section 3.54; and
   (b) if estimating emissions of methane released—one of the following methods must be used:
      (i) method 1 under section 3.52;
      (ii) method 2A under section 3.53A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:
  (i) method 1 under section 3.52;
  (ii) method 2A under section 3.53A.

Note: There is no method 4 under paragraph (a) and no method 2, 3 or 4 under paragraph (b) or (c).

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.52 Method 1—crude oil production (flared) emissions

(1) For subparagraph 3.51(a)(i), method 1 is:

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

where:

E_{ij} is the emissions of gas type (***j***) measured in CO_2-e tonnes from a fuel type (***i***) flared in crude oil production during the year.

Q_i is the quantity of fuel type (***i***) measured in tonnes flared in crude oil production during the year.

EF_{ij} is the emission factor for gas type (***j***) measured in tonnes of CO_2-e emissions per tonne of the fuel type (***i***) flared.

(2) For EF_{ij} mentioned in subsection (1), columns 3, 4 and 5 of an item in following table specify the emission factor for each fuel type (***i***) specified in column 2 of that item.

Item	Fuel type (i)	Emission factor for gas type (j) (tonnes CO_2-e/tonnes of fuel flared)		
		CO_2	CH_4	N_2O
1	Unprocessed gas flared	2.8	0.8	0.03
2	Crude oil	3.2	0.008	0.07

3.53 Method 2—crude oil production

Combustion of gaseous fuels (flared) emissions of carbon dioxide

(1) For subparagraph 3.51(1)(a)(ii), method 2 for combustion of gaseous fuels is:

$$E_{ico_2} = Q_h \times EF_h \times OF_i + QCO_2$$

where:

E_{iCO_2} is the fugitive emissions of CO_2 from fuel type (***i***) flared in crude oil production during the year, measured in CO_2-e tonnes.

$\boldsymbol{Q_h}$ is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in crude oil production during the year, measured in tonnes in accordance with Division 2.3.3.

$\boldsymbol{EF_h}$ is the emission factor for the total hydrocarbons (***h***) within the fuel type (***i***) in crude oil production during the year, measured in CO_2-e tonnes per tonne of fuel type (***i***) flared, estimated in accordance with method 2 in Division 2.3.3.

$\boldsymbol{OF_i}$ is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

$\boldsymbol{QCO_2}$ is the quantity of CO_2 within the fuel type (***i***) in crude oil production during the year, measured in CO_2-e tonnes in accordance with Division 2.3.3.

Combustion of liquid fuels (flared) emissions of carbon dioxide

(2) For subparagraph 3.51(1)(a)(ii), method 2 for combustion of liquid fuels is the same as method 1, but the carbon dioxide emissions factor $\boldsymbol{EF_h}$ must be determined in accordance with method 2 in Division 2.4.3.

3.53A Method 2A—crude oil production (flared methane or nitrous oxide emissions)

For subparagraphs 3.51(1)(b)(ii) and (c)(ii), method 2A is:

$$E_{ij} = Q_h \times EF_{hij} \times OF_i$$

where:

$\boldsymbol{EF_{hij}}$ is the emission factor of gas type (***j***), being methane or nitrous oxide, for the total hydrocarbons (***h***) within the fuel type (***i***) in crude oil production during the year, mentioned for the fuel type in the table in subsection 3.52(2) and measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared.

$\boldsymbol{E_{ij}}$ is the fugitive emissions of gas type (***j***), being methane or nitrous oxide, from fuel type (***i***) flared from crude oil production during the year, measured in CO_2-e tonnes.

$\boldsymbol{OF_i}$ is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

$\boldsymbol{Q_h}$ is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in crude oil production during the year, measured in tonnes in accordance with Division 2.3.3 for gaseous fuels or Division 2.4.3 for liquid fuels.

3.54 Method 3—crude oil production

Combustion of gaseous fuels (flared) emissions of carbon dioxide

(1) For subparagraph 3.51(1)(a)(iii), method 3 for the combustion of gaseous fuels is the same as method 2, but the carbon dioxide emissions factor $\boldsymbol{EF_h}$ must be determined in accordance with method 3 in Division 2.3.4.

Combustion of liquid fuels (flared) emissions of carbon dioxide

(2) For subparagraph 3.51(1)(a)(iii), method 3 for the combustion of liquid fuels is the same as method 2, but the carbon dioxide emissions factor EF_h must be determined in accordance with method 3 in Division 2.4.4.

Subdivision 3.3.3.4—Crude oil production (non-flared)—fugitive vent emissions of methane and carbon dioxide

3.56A Available methods

(1) Subject to section 1.18, the methods mentioned in subsections (2) and (3) must be used for estimating fugitive emissions that result from system upsets, accidents and deliberate releases from process vents during a year from the operation of a facility that is constituted by crude oil production.

(2) To estimate emissions that result from deliberate releases from process vents, system upsets and accidents during a year from the operation of the facility, one of the following methods must be used:

- (a) method 1 under section 3.84;
- (b) method 4 under Part 1.3.

(3) For estimating incidental emissions that result from deliberate releases from process vents, system upsets and accidents during a year from the operation of the facility, another method may be used that is consistent with the principles mentioned in section 1.13.

Note: There is no method 2 or 3 for this Subdivision.

Division 3.3.4—Crude oil transport

3.57 Application

This Division applies to fugitive emissions from crude oil transport activities, other than emissions that are flared.

3.58 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating fugitive emissions of methane released during a year from the operation of a facility that is constituted by crude oil transport:

(a) method 1 under section 3.59;

(b) method 2 under section 3.60.

Note: There is no method 3 or 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.59 Method 1—crude oil transport

Method 1 is:

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

where:

E_{ij} is the fugitive emissions of methane (***j***) from the crude oil transport during the year measured in CO_2-e tonnes.

Q_i is the quantity of crude oil (***i***) measured in tonnes and transported during the year.

EF_{ij} is the emission factor for methane (***j***), which is 8.7×10^{-4} tonnes CO_2-e per tonnes of crude oil transported during the year.

3.60 Method 2—fugitive emissions from crude oil transport

(1) Method 2 is:

$$E_{ij} = \Sigma_k (Q_{ik} \times EF_{ijk})$$

where:

E_{ij} is the fugitive emissions of methane (***j***) from the crude oil transport during the year measured in CO_2-e tonnes.

Σ_k is the emissions of methane (***j***) measured in tonnes of CO_2-e and estimated by summing up the emissions from each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil transport.

Q_{ik} is the total of the quantities of crude oil measured in tonnes that pass through each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil transport.

EF_{ijk} is the emission factor of methane (***j***) measured in tonnes of CO_2-e per tonne of crude oil that passes though each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil transport.

(2) For EF_{ijk}, the emission factors for methane (***j***), as crude oil passes through equipment type (***k***), are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium, for the equipment type; or

(b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors.

Division 3.3.5—Crude oil refining

3.61 Application

This Division applies to fugitive emissions from crude oil refining activities, including emissions from flaring at petroleum refineries.

3.62 Available methods

(1) Subject to section 1.18, for estimating emissions released during a year from the operation of a facility that is constituted by crude oil refining the methods as set out in this section must be used.

Crude oil refining and storage tanks

(2) One of the following methods must be used for estimating fugitive emissions of methane that result from crude oil refining and from storage tanks for crude oil:
  (a) method 1 under section 3.63;
  (b) method 2 under section 3.64.

Note: There is no method 3 or 4 for subsection (2).

Process vents, system upsets and accidents

(3) One of the following methods must be used for estimating fugitive emissions of each type of gas, being carbon dioxide, methane and nitrous oxide, that result from deliberate releases from process vents, system upsets and accidents:
  (a) method 1 under section 3.65;
  (b) method 4 under section 3.66.

Note: There is no method 2 or 3 for subsection (3).

Flaring

(4) For estimating emissions released from gas flared from crude oil refining:
  (a) one of the following methods must be used for estimating emissions of carbon dioxide released:
    (i) method 1 under section 3.67;
    (ii) method 2 under section 3.68;
    (iii) method 3 under section 3.69; and
  (b) if estimating emissions of methane released—one of the following methods must be used:
    (i) method 1 under section 3.67;
    (ii) method 2A under section 3.68A; and
  (c) if estimating emissions of nitrous oxide released—one of the following methods must be used:
    (i) method 1 under section 3.67;
    (ii) method 2A under section 3.68A.

Note: The flaring of gas from crude oil refining releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 under section 3.67 is a reference to these gases. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

(5) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

Subdivision 3.3.5.1—Fugitive emissions from crude oil refining and from storage tanks for crude oil

3.63 Method 1—crude oil refining and storage tanks for crude oil

Method 1 is:

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

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of methane (***j***) from fuel type (***i***) being crude oil refined or stored in tanks during the year measured in CO_2-e tonnes.

$\boldsymbol{\sum_I}$ is the sum of emissions of methane (***j***) released during refining and from storage tanks during the year.

$\boldsymbol{Q_i}$ is the quantity of crude oil (***i***) refined or stored in tanks during the year measured in tonnes.

$\boldsymbol{EF_{ij}}$ is the emission factor for methane (***j***) being 8.5×10^{-4} tonnes CO_2-e per tonne of crude oil refined and 1.5×10^{-4} tonnes CO_2-e per tonne of crude oil stored in tanks.

3.64 Method 2—crude oil refining and storage tanks for crude oil

(1) Method 2 is:

$$E_{ij} = \Sigma_k \; (Q_{ik} \times EF_{ijk})$$

where:

$\boldsymbol{E_{ij}}$ is the fugitive emissions of methane (***j***) from the crude oil refining and from storage tanks during the year measured in CO_2-e tonnes.

$\boldsymbol{\Sigma_k}$ is the emissions of methane (***j***) measured in tonnes of CO_2-e estimated by summing up the emissions released from each equipment types (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil refining and in the storage tanks.

$\boldsymbol{Q_{ik}}$ is the total of the quantities of crude oil measured in tonnes that pass through each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil refining and in the storage tanks.

EF_{ijk} is the emission factor for methane (***j***) measured in tonnes of CO_2-e per tonne of crude oil that passes though each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the crude oil refining and in the storage tanks.

(2) For ***EF_{ijk}***, the emission factors for methane (***j***) as the crude oil passes through an equipment type (***k***) are:

- (a) as listed in sections 5 and 6.1.2 of the API Compendium, for the equipment type; or
- (b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors.

Subdivision 3.3.5.2—Fugitive emissions from deliberate releases from process vents, system upsets and accidents

3.65 Method 1—fugitive emissions from deliberate releases from process vents, system upsets and accidents

Method 1 is:

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

where:

E_i is the fugitive emissions of carbon dioxide during the year from deliberate releases from process vents, system upsets and accidents in the crude oil refining measured in CO_2-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***) as mentioned in Schedule 3.

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

3.66 Method 4—deliberate releases from process vents, system upsets and accidents

(1) Method 4 is:

- (a) is as set out in Part 1.3; or
- (b) uses the process calculation approach in section 5.2 of the API Compendium.

(2) For paragraph (1)(b), all carbon monoxide is taken to fully oxidise to carbon dioxide and must be included in the calculation.

Subdivision 3.3.5.3—Fugitive emissions released from gas flared from the oil refinery

3.67 Method 1—gas flared from crude oil refining

(1) Method 1 is:

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

where:

$\boldsymbol{E_{ij}}$ is the emissions of gas type (***j***) released from the gas flared in the crude oil refining during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of gas type (***i***) flared during the year measured in tonnes.

$\boldsymbol{EF_{ij}}$ is the emission factor for gas type (***j***) measured in tonnes of CO_2-e emissions per tonne of gas type (***i***) flared in the crude oil refining during the year.

(2) For $\boldsymbol{EF_{ij}}$ in subsection (1), columns 3, 4 and 5 of an item in the following table specify the emission factor for gas type (***j***) for the fuel type (***i***) specified in column 2 of that item:

Item	fuel type (i)	Emission factor of gas type (j) (tonnes CO_2-e/tonnes fuel flared)		
		CO_2	CH_4	N_2O
1	gas	2.7	0.1	0.03

3.68 Method 2—gas flared from crude oil refining

For subparagraph 3.62(4)(a)(ii), method 2 is:

$$E_{ico_2} = Q_h \times EF_h \times OF_i + QCO_2$$

where:

$\boldsymbol{E_{iCO_2}}$ is the fugitive emissions of CO_2 from fuel type (***i***) flared in crude oil refining during the year, measured in CO_2-e tonnes.

$\boldsymbol{Q_h}$ is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in crude oil refining during the year, measured in tonnes in accordance with Division 2.3.3.

$\boldsymbol{EF_h}$ is the emission factor for the total hydrocarbons (***h***) within the fuel type (***i***) in the crude oil refining during the year, measured in CO_2-e tonnes per tonne of fuel type (***i***) flared, estimated in accordance with method 2 in Division 2.3.3.

$\boldsymbol{OF_i}$ is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

$\boldsymbol{QCO_2}$ is the quantity of CO_2 within the fuel type (***i***) in the crude oil refining during the year, measured in CO_2-e tonnes in accordance with Division 2.3.3.

3.68A Method 2A—crude oil refining (flared methane or nitrous oxide emissions)

For subparagraphs 3.62(4)(b)(ii) and (c)(ii), method 2A is:

$$E_{ij} = Q_h \times EF_{hij} \times OF_i$$

where:

EF_{hij} is the emission factor of gas type (***j***), being methane or nitrous oxide, for the total hydrocarbons (***h***) within the fuel type (***i***) in crude oil refining during the year, mentioned for the fuel type in the table in subsection 3.67(2) and measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared.

E_{ij} is the fugitive emissions of gas type (***j***), being methane or nitrous oxide, from fuel type (***i***) flared from crude oil refining during the year, measured in CO_2-e tonnes.

OF_i is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

Q_h is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in crude oil refining during the year, measured in tonnes in accordance with Division 2.3.3.

3.69 Method 3—gas flared from crude oil refining

For subparagraph 3.62(4)(a)(iii), method 3 is the same as method 2 under section 3.68, but the emission factor EF_{ij} must be determined in accordance with method 3 for the consumption of gaseous fuels as specified in Division 2.3.4.

Division 3.3.6—Natural gas production or processing, other than emissions that are vented or flared

3.70 Application

This Division applies to fugitive emissions from natural gas production or processing activities, other than emissions that are vented or flared, including emissions from:

(a) a gas wellhead through to the inlet of gas processing plants; and

(b) a gas wellhead through to the tie-in points on gas transmission systems, if processing of natural gas is not required; and

(c) gas processing plants; and

(d) well servicing; and

(e) gas gathering; and

(f) gas processing and associated waste water disposal and acid gas disposal activities.

3.71 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating fugitive emissions of methane (other than emissions that are vented or flared) released during a year from the operation of a facility that is constituted by natural gas production and processing:

(a) method 1 under section 3.72;

(b) method 2 under section 3.73.

Note: There is no method 3 or 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.72 Method 1—natural gas production and processing (other than emissions that are vented or flared)

(1) Method 1 is:

$$E_{ij} = \Sigma_k \left(Q_{ik} \times EF_{ijk}\right) + Q_i \times EF_{(l)\,ij}$$

where:

E_{ij} is the fugitive emissions of methane (***j***) (other than emissions that are vented or flared) from the natural gas production and processing during the year measured in CO_2-e tonnes.

Σ_k is the total emissions of methane (***j***), measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) specified in column 2 of an item in the table in subsection (2), if the equipment is used in the natural gas production and processing.

Q_{ik} is the total of the quantities of natural gas that pass through each equipment type (***k***), or the number of equipment units of type (***k***) specified in column 2 of the table in subsection (2), measured in tonnes.

EF_{ijk} is the emission factor for methane (***j***) measured in CO_2-e tonnes per tonne of natural gas that passes through each equipment type (***k***) during the year if the equipment is used in the natural gas production and processing.

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 x 10^{-3}, which is the emission factor for methane (***j***) from general leaks in the natural gas production and processing, measured in CO_2-e tonnes per tonne of natural gas that passes through the natural gas production and processing.

(2) For EF_{ijk} in subsection (1), column 3 of an item in the following table specifies the emission factor for methane (***j***) for an equipment type (***k***) specified in column 2 of that item:

Item	Equipment type (k)	Emission factor for methane (j) (tonnes $CO_{2\text{-}e}$/tonnes fuel throughput)
1	Internal floating tank	1.0×10^{-7}
2	Fixed roof tank	5.0×10^{-6}
3	Floating tank	3.8×10^{-6}

(3) For $EF_{(l)\,ij}$ in subsection (1), general leaks in the natural gas production and processing comprise the emissions (other than vent emissions) from equipment listed in sections 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas production and processing.

3.73 Method 2—natural gas production and processing (other than venting and flaring)

(1) Method 2 is:

$$E_{ij} = \Sigma_k \left(Q_{ik} \times EF_{ijk}\right)$$

where:

E_{ij} is the fugitive emissions of methane (***j***) from the natural gas production and processing during the year measured in CO_2-e tonnes.

Σ_k is the emissions of methane (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) listed in sections 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas production and processing.

Q_{ik} is the total of the quantities of natural gas measured in tonnes that pass through each equipment type (***k***) listed in sections 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas production and processing.

EF_{ijk} is the emission factor of methane (***j***) measured in tonnes of CO_2-e per tonne of natural gas that passes through each equipment type (***k***) listed in sections 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas production and processing.

(2) For EF_{ijk}, the emission factors for methane (***j***) as the natural gas passes through the equipment types (***k***) are:

(a) as listed in sections 5.4.1, 5.4.2, 5.4.3, 5.6.4, 5.6.5 and 6.1.2 of the API Compendium, for the equipment type; or

(b) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors.

Division 3.3.7—Natural gas transmission

3.74 Application

This Division applies to fugitive emissions from natural gas transmission activities.

3.75 Available methods

(1) Subject to section 1.18 and subsection (2), one of the following methods must be used for estimating fugitive emissions of each gas type, being carbon dioxide and methane, released from the operation of a facility that is constituted by natural gas transmission through a system of pipelines during a year:

(a) method 1 under section 3.76;

(b) method 2 under section 3.77.

Note: There is no method 3 or 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.76 Method 1—natural gas transmission

Method 1 is:

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

where:

E*$_{ij}$** is the fugitive emissions of gas type (j***) from natural gas transmission through a system of pipelines of length (***i***) during the year measured in CO_2-e tonnes.

Q*$_i$** is the length of the system of pipelines (i***) measured in kilometres.

EF*$_{ij}$** is the emission factor for gas type (j***), which is 0.02 for carbon dioxide and 10.4 for methane, measured in tonnes of CO_2-e emissions per kilometre of pipeline (***i***).

3.77 Method 2—natural gas transmission

(1) Method 2 is:

$$E_j = \Sigma_k \ (Q_k \times EF_{jk})$$

where:

E*$_j$** is the fugitive emissions of gas type (j***) measured in CO_2-e tonnes from the natural gas transmission through the system of pipelines during the year.

Σ*$_k$** is the total of emissions of gas type (j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas transmission.

$\boldsymbol{Q}_k$ is the total of the quantities of natural gas measured in tonnes that pass through each equipment type (***k***) or the number of equipment units of type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas transmission.

$\boldsymbol{EF}_{jk}$ is the emission factor of gas type (***j***) measured in CO_2-e tonnes for each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, where the equipment is used in the natural gas transmission.

(2) For $\boldsymbol{EF}_{jk}$, the emission factors for a gas type (***j***) as the natural gas passes through the equipment type (***k***) are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium, for the equipment type; or

(b) as listed in that Compendium for the equipment type with emission factors adjusted for variations in estimated gas composition, in accordance with that Compendium's sections 5 and 6.1.2, and the requirements of Division 2.3.3; or

(c) as listed in that Compendium for the equipment type with emission factors adjusted for variations in the type of equipment material estimated in accordance with the results of published research for the crude oil industry and the principles of section 1.13; or

(d) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors; or

(e) estimated using the engineering calculation approach in accordance with sections 5 and 6.1.2 of the API Compendium.

Note: The API Compendium is available at www.api.org.

Division 3.3.8—Natural gas distribution

3.78 Application

This Division applies to fugitive emissions from natural gas distribution activities.

3.79 Available methods

(1) Subject to section 1.18 and subsection (2), one of the following methods must be used for estimating fugitive emissions of each gas type, being carbon dioxide and methane, released during a year from the operation of a facility that is constituted by natural gas distribution through a system of pipelines:

(a) method 1 under section 3.80;

(b) method 2 under section 3.81.

Note: There is no method 3 or 4 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

3.80 Method 1—natural gas distribution

(1) Method 1 is:

$$E_{jp} = S_p \times \%UAG_p \times 0.55 \times C_{jp}$$

where:

$\boldsymbol{E_{jp}}$ is the fugitive emissions of gas type (***j***) that result from natural gas distribution through a system of pipelines with sales of gas in a State or Territory (***p***) during the year, measured in CO_2-e tonnes.

$\boldsymbol{S_p}$ is the total sales during the year from the pipeline system in a State or Territory (***p***), measured in terajoules.

$\boldsymbol{\%UAG_p}$ is the percentage of unaccounted for gas in the pipeline system in a State or Territory, relative to the amount of gas issued annually by gas utilities in that State or Territory.

Note: The value 0.55 following the variable %UAGp in method 1 represents the proportion of gas that is unaccounted for and released as emissions.

$\boldsymbol{C_{jp}}$ is the natural gas composition factor for gas type (***j***) for the natural gas supplied from the pipeline system in a State or Territory (***p***), measured in CO_2-e tonnes per terajoule.

(2) For %UAGp in subsection (1), column 3 of an item in the following table specifies the percentage of unaccounted for gas in the pipeline system in a State or Territory specified in column 2 of that item.

(3) For ***C**$_{jp}$* in subsection (1), columns 4 and 5 of an item in the following table specify the natural gas composition factor for carbon dioxide and methane for a pipeline system in a State or Territory specified in column 2.

Item	**State**	**Unaccounted for gas (a)%**	**Natural gas composition factor (a)(tonnes CO_{2-e}/TJ)**	
		UAGp	**CO_2**	**CH_4**
1	NSW and ACT	2.2	0.8	390
2	VIC	3.0	0.9	388
3	QLD	1.7	0.8	377
4	WA	2.9	1.1	364
5	SA	4.9	0.8	390
6	TAS	0.2	0.9	388
7	NT	2.2	0.0	314

3.81 Method 2—natural gas distribution

(1) Method 2 is:

$$E_j = \Sigma_k \ (Q_k \times EF_{jk})$$

where:

E**$_j$* is the fugitive emissions of gas type (j***) that result from the natural gas distribution during the year measured in CO_2-e tonnes.

Σ**$_k$* is the total of emissions of gas type (j***) measured in CO_2-e tonnes and estimated by summing up the emissions from each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas distribution.

Q**$_k$* is the total of the quantities of natural gas measured in tonnes that pass through each equipment type (k***) or the number of equipment units of type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas distribution.

EF**$_{jk}$* is the emission factor for gas type (j***) measured in CO_2-e tonnes for each equipment type (***k***) listed in sections 5 and 6.1.2 of the API Compendium, if the equipment is used in the natural gas distribution.

(2) For ***EF**$_{jk}$*, the emission factors for gas type (***j***) as the natural gas passes through the equipment type (***k***) are:

(a) as listed in sections 5 and 6.1.2 of the API Compendium; or

(b) as listed in that Compendium for the equipment type with emission factors adjusted for variations in estimated gas composition, in accordance with that Compendium's Sections 5 and 6.1.2, and the requirements of Division 2.3.3; or

(c) as listed in that Compendium for the equipment type with emission factors adjusted for variations in the type of equipment material using adjusted factors; or

(d) if the manufacturer of the equipment supplies equipment-specific emission factors for the equipment type—those factors.

(3) In paragraph 3.81(2)(c), a reference to ***factors adjusted*** is a reference to the factors in Table 5-3 of the publication entitled *Greenhouse Gas Emission Estimation Methodologies, Procedures and Guidelines for the Natural Gas Distribution Sector*, American Gas Association, April 2008, that are adjusted for variations in estimated gas composition in accordance with:

(a) section 5.2.1 of that publication; and

(b) Division 2.3.3.

Division 3.3.9—Natural gas production or processing (emissions that are vented or flared)

3.82 Application

This Division applies to fugitive emissions from venting or flaring from natural gas production or processing activities, including emissions from:

(a) the venting of natural gas; and

(b) the venting of waste gas and vapour streams at facilities that are constituted by natural gas production or processing; and

(c) the flaring of natural gas, waste gas and waste vapour streams at those facilities.

3.83 Available methods

(1) Subject to section 1.18, for estimating emissions (emissions that are vented or flared) released during a year from the operation of a facility that is constituted by natural gas production and processing the methods as set out in this section must be used.

(2) One of the following methods must be used for estimating fugitive emissions that result from deliberate releases from process vents, system upsets and accidents:

(i) method 1 under section 3.84; and

(ii) method 4 under Part 1.3.

Note: There is no method 2 or 3 for subsection (2).

(3) For estimating emissions released from gas flared from natural gas production and processing:

(a) one of the following methods must be used for estimating emissions of carbon dioxide released:

(i) method 1 under section 3.85;

(ii) method 2 under section 3.86;

(iii) method 3 under section 3.87; and

(b) if estimating emissions of methane released—one of the following methods must be used:

(i) method 1 under section 3.85;

(ii) method 2A under section 3.86A; and

(c) if estimating emissions of nitrous oxide released—one of the following methods must be used:

(i) method 1 under section 3.85;

(ii) method 2A under section 3.86A.

Note: The flaring of gas from natural gas production and processing releases emissions of carbon dioxide, methane and nitrous oxide. The reference to gas type (***j***) in method 1 in section 3.85 is a reference to these gases. The same formula is used to estimate emissions of each of these gases. There is no method 4 for emissions of carbon dioxide and no method 2, 3 or 4 for emissions of nitrous oxide or methane.

(4) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

Subdivision 3.3.9.1—Fugitive emissions that result from deliberate releases from process vents, system upsets and accidents

3.84 Method 1—emissions from system upsets, accidents and deliberate releases from process vents

Method 1 is, for a process mentioned in column 2 of an item in the following table, as described in the section of the API Compendium mentioned in column 3 for the item.

Item	Emission process	API Compendium section
1	Gas treatment processes	Section 5.1
2	Cold process vents	Section 5.3
3	Natural gas blanketed tank emissions	Section 5.4.4
4	Other venting sources—gas driven pneumatic devices	Section 5.6.1
5	Other venting sources—gas driven chemical injection pumps	Section 5.6.2
6	Other venting sources—coal seam exploratory drilling, well testing and mud degassing	Section 5.6.3 and 5.6.6
7	Non-routine activities—production related non-routine emissions	Section 5.7.1 or 5.7.2
8	Non-routine activities—gas processing related non-routine emissions	Section 5.7.1 or 5.7.3

Subdivision 3.3.9.2—Emissions released from gas flared from natural gas production and processing

3.85 Method 1—gas flared from natural gas production and processing

(1) Method 1 is:

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

where:

E_{ij} is the emissions of gas type (***j***) measured in CO_2-e tonnes that result from a fuel type (***i***) flared in the natural gas production and processing during the year.

Q_i is the quantity measured in tonnes of gas flared during the year.

EF_{ij} is the emission factor for gas type (***j***) measured in CO_2-e tonnes of emissions per tonne of gas flared (***i***) in the natural gas production and processing during the year.

(2) For EF_{ij} mentioned in subsection (1), columns 3, 4 and 5 of an item in the following table specify the emission factor for fuel type (***i***) specified in column 2 of that item.

Item	**fuel type (i)**	**Emission factor of gas type (j) (tonnes CO_2-e/tonnes fuel flared)**		
		CO_2	**CH_4**	**N_2O**
1	gas	2.7	0.1	0.03

3.86 Method 2—gas flared from natural gas production and processing

For subparagraph 3.83(3)(a)(ii), method 2 is:

$$E_{ico_2} = Q_h \times EF_{hi} \times OF_i + QCO_2$$

where:

E_{iCO_2} is the fugitive emissions of CO_2 from fuel type (***i***) flared in the natural gas production and processing during the year, measured in CO_2-e tonnes.

Q_h is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in the natural gas production and processing during the year, measured in tonnes in accordance with Division 2.3.3.

EF_{hi} is the carbon dioxide emission factor for the total hydrocarbons (***h***) within the fuel type (***i***) in the natural gas production and processing during the year, measured in CO_2-e tonnes per tonne of fuel type (***i***) flared, estimated in accordance with Division 2.3.3.

OF_i is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

QCO_2 is the quantity of CO_2 within the fuel type (***i***) in the natural gas production and processing during the year, measured in CO_2-e tonnes in accordance with Division 2.3.3.

3.86A Method 2A—natural gas production and processing (flared methane or nitrous oxide emissions)

For subparagraphs 3.83(3)(b)(ii) and (c)(ii), method 2A is:

$$E_{ij} = Q_h \times EF_{hij} \times OF_i$$

where:

EF_{hij} is the emission factor of gas type (***j***), being methane or nitrous oxide, for the total hydrocarbons (***h***) within the fuel type (***i***) in natural gas production and processing during the year, mentioned for the fuel type in the table in subsection 3.85(2) and measured in CO_2-e tonnes per tonne of the fuel type (***i***) flared.

E_{ij} is the fugitive emissions of gas type (***j***), being methane or nitrous oxide, from fuel type (***i***) flared from natural gas production and processing during the year, measured in CO_2-e tonnes.

OF_i is 0.98, which is the destruction efficiency of fuel type (***i***) flared.

Q_h is the total quantity of hydrocarbons (***h***) within the fuel type (***i***) in natural gas production and processing during the year, measured in tonnes in accordance with Division 2.3.3.

3.87 Method 3—gas flared from natural gas production and processing

For subparagraph 3.83(3)(a)(iii), method 3 is the same as method 2 under section 3.86, but the emission factor (EF_{ij}) must be determined in accordance with method 3 for the consumption of gaseous fuels as specified in Division 2.3.4.

Part 3.4—Carbon capture and storage—fugitive emissions

Division 3.4.1—Preliminary

3.88 Outline of Part

This Part provides for fugitive emissions from carbon capture and storage.

Division 3.4.2—Transport of greenhouse gases

Subdivision 3.4.2.1—Preliminary

3.89 Application

This Division applies to fugitive emissions from the transport of a greenhouse gas captured for permanent storage.

Note: Section 1.19A defines when a greenhouse gas is captured for permanent storage.

3.90 Available methods

(1) Subject to section 1.18, for estimating emissions released during a year from the operation of a facility that is constituted by the transport of a greenhouse gas captured for permanent storage the methods as set out in this section must be used.

Emissions from transport of a greenhouse gas involving transfer

(2) If the greenhouse gas is transferred to a relevant person for injection by the person in accordance with a licence, lease or approval mentioned in section 1.19A, one of the following methods must be used for estimating fugitive emissions of the greenhouse gas that result from the transport of the greenhouse gas stream for that injection:

(a) method 1 under section 3.91 (which deals with injection);

(b) method 2 under section 3.77 (which deals with transport), applied in relation to the greenhouse gas as if it were a type of natural gas.

Note 1: There is no method 3 or 4 for subsection (2).

Note 2: The same emissions cannot be counted under both the method mentioned in paragraph (2)(a) (injection) and the method mentioned in paragraph (2)(b) (transport).

Emissions from transport of a greenhouse gas not involving transfer

(2A) Subsection (3) applies if:

(a) the greenhouse gas is captured by a relevant person for injection in accordance with a licence, lease or approval mentioned in section 1.19A; and

(b) the greenhouse gas is not transferred to another person for the purpose of injection.

(3) One of the following methods must be used for estimating fugitive emissions of the greenhouse gases that result from the transport of the greenhouse gas stream for that injection:

(a) method 1 under section 3.92 (which deals with injection);

(b) method 2 under section 3.77 (which deals with transport), applied in relation to the greenhouse gas as if it were a type of natural gas.

Note 1: There is no method 3 or 4 for subsection (3).

Note 2: The same emissions cannot be counted under both the method mentioned in paragraph (3)(a) (injection) and the method mentioned in paragraph (3)(b) (transport).

(4) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

Subdivision 3.4.2.2—Emissions from transport of greenhouse gases involving transfer

3.91 Method 1—emissions from transport of greenhouse gases involving transfer

For subsection 3.90(2), method 1 is:

$$E_j = \gamma_j \left(RCCS_j - Q_{inj} \right) - E_{ij}$$

where:

E_j is the emissions of gas type (***j***), during the year from transportation of greenhouse gas captured for permanent storage to the storage site, measured in CO_2-e tonnes.

γ_j is the factor for converting a quantity of gas type (***j***) from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes, being:

(a) for methane—$6.784 \times 10^{-4} \times 25$; and
(b) for carbon dioxide—1.861×10^{-3}; and
(c) for any other gas type—the appropriate conversion factor for the gas type.

Q_{inj} is the quantity of greenhouse gas injected into the storage site during the year and measured in cubic metres at standard conditions of pressure and temperature.

$RCCS_j$ is the quantity of gas type (***j***) captured during the year worked out under Division 1.2.3 and measured in cubic metres at standard conditions of pressure and temperature.

E_{ij} is the fugitive emissions (***j***) from the injection of a greenhouse gas into a geological formation during the reporting year, measured in CO_2-e tonnes and calculated in accordance with Subdivision 3.4.3.2.

Subdivision 3.4.2.3—Emissions from transport of greenhouse gases not involving transfer

3.92 Method 1—emissions from transport of greenhouse gases not involving transfer

For subsection 3.90(3), method 1 is:

$$E_j = \gamma_j \left(RCCS_j - Q_{inj} \right)$$

where:

$\boldsymbol{E_j}$ is the emissions of gas type (***j***), during the year from transportation of greenhouse gas captured for permanent storage to the storage site, measured in CO_2-e tonnes.

$\boldsymbol{\gamma_j}$ is the factor for converting a quantity of gas type (***j***) from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes, being:

(a) for methane—$6.784 \times 10^{-4} \times 25$; and

(b) for carbon dioxide—1.861×10^{-3}; and

(c) for any other gas type—the appropriate conversion factor for the gas type.

$\boldsymbol{Q_{inj}}$ is the quantity of greenhouse gas injected into the storage site during the year and measured in cubic metres at standard conditions of pressure and temperature.

$\boldsymbol{RCCS_j}$ is the quantity of gas type (***j***) captured during the year worked out under Division 1.2.3 and measured in cubic metres at standard conditions of pressure and temperature.

Division 3.4.3—Injection of greenhouse gases

Subdivision 3.4.3.1—Preliminary

3.93 Application

This Division applies to fugitive emissions of greenhouse gases from the injection of a greenhouse gas captured for permanent storage into a geological formation.

Note: A greenhouse gas is ***captured for permanent storage*** in a geological formation if the gas is captured by, or transferred to, the holder of a licence, lease or approval mentioned in section 1.19A, under a law mentioned in that section, for the purpose of being injected into a geological formation (however described) under the licence, lease or approval.

3.94 Available methods

(1) For estimating fugitive emissions of greenhouse gases released during a year from the injection of a greenhouse gas captured for permanent storage into a geological formation, the methods set out in this section must be used.

Process vents, system upsets and accidents

(2) Method 2 under section 3.95 must be used for estimating fugitive emissions of greenhouse gases that result from deliberate releases from process vents, system upsets and accidents.

Fugitive emissions of greenhouse gases other than from process vents, system upsets and accidents

(3) One of the following methods must be used for estimating fugitive emissions of greenhouse gases from the injection of a greenhouse gas captured for permanent storage into a geological formation that are not the result of deliberate releases from process vents, system upsets and accidents:
- (a) method 2 under section 3.96;
- (b) method 3 under section 3.97.

Note: There is no method 1, 3 or 4 for subsection (2) and no method 1 or 4 for subsection (3).

Subdivision 3.4.3.2—Fugitive emissions from deliberate releases from process vents, system upsets and accidents

3.95 Method 2—fugitive emissions from deliberate releases from process vents, system upsets and accidents

Method 2 is the same as the approach mentioned in section 5.3 or 5.7.1 of the API Compendium.

Subdivision 3.4.3.3—Fugitive emissions from injection of greenhouse gases (other than emissions from deliberate releases from process vents, system upsets and accidents)

3.96 Method 2—fugitive emissions from injection of a greenhouse gas into a geological formation (other than deliberate releases from process vents, system upsets and accidents)

(1) Method 2 is:

$$E_{ij} = \sum\nolimits_k \left(Q_{ik} \times EF_{ijk} \right)$$

where:

EF*$_{ijk}$** is the emission factor (j***) measured in CO_2-e tonnes that passes through each equipment type (***k***) mentioned in section 6.1 of the API Compendium, if the equipment type was used in the injection of a greenhouse gas into the geological formation.

E*$_{ij}$** is the fugitive emissions (j***) from the injection of a greenhouse gas into a geological formation during the reporting year, measured in CO_2-e tonnes.

Σ_k is the emissions (***j***) measured in CO_2-e tonnes and estimated by summing up the emissions released from each equipment type (***k***) mentioned in section 6.1 of the API Compendium, if the equipment type was used in the injection of a greenhouse gas into the geological formation.

Q*$_{ik}$** is the total of the quantities of greenhouse gas measured in tonnes that pass through each equipment type (k***) mentioned in section 6.1 of the API Compendium, if the equipment type was used in the injection of a greenhouse gas into the geological formation.

(2) For ***EF*$_{ijk}$** in subsection (1), the emission factors are:

(a) the emission factors listed for the equipment type in section 6.1 of the API Compendium; or

(b) if the manufacturer of the equipment supplies equipment specific emissions factors for the equipment type—those factors.

3.97 Method 3—fugitive emissions from injection of greenhouse gases (other than deliberate releases from process vents, system upsets and accidents)

Method 3 is the same as an approach mentioned in Appendix C to the API Compendium.

Note: For this method, any approach mentioned in Appendix C to the API Compendium may be used.

Division 3.4.4—Storage of greenhouse gases

Subdivision 3.4.4.1—Preliminary

3.98 Application

This Division applies to fugitive emissions to the atmosphere of greenhouse gases from geological formations used for storage of a greenhouse gas captured for permanent storage.

Note: A greenhouse gas is ***captured for permanent storage*** in a geological formation if the gas is captured by, or transferred to, the holder of a licence, lease or approval mentioned in section 1.19A, under a law mentioned in that section, for the purpose of being injected into a geological formation (however described) under the licence, lease or approval.

3.99 Available method

For estimating fugitive emissions of greenhouse gases released during a year from a geological formation used for the permanent storage of a greenhouse gas, method 2 set out in section 3.100 must be used.

Note: There is no method 1, 3 or 4 for this Division.

Subdivision 3.4.4.2—Fugitive emissions from the storage of greenhouse gases

3.100 Method 2—fugitive emissions from geological formations used for the storage of greenhouse gases

(1) Method 2 is:

$$C_{cst} = C_{ost} + Q_{inj} - E_{co_2}$$

where:

C_{cst} is the closing stock of a stored greenhouse gas at the storage site for the reporting year, measured in CO_2-e tonnes.

C_{ost} is the opening stock of a stored greenhouse gas at the storage site for the reporting year, determined in accordance with subsection (2), measured in CO_2-e tonnes.

E_{CO_2} is the fugitive emissions to the atmosphere of greenhouse gas during the reporting year from the geological storage formation, determined in accordance with subsection (3), measured in CO_2-e tonnes.

Q_{inj} is the quantity of a greenhouse gas injected into the geological formation during the reporting year, measured in CO_2-e tonnes.

Note: This formula represents C_{cst} (the closing stock) as the cumulative mass of a greenhouse gas injected into the geological formation in all years since the commencement of injection, less any fugitive emissions to the atmosphere.

The closing stock of a greenhouse gas in the storage site for the reporting year is derived from the opening stock determined in accordance with subsection (2), the quantity injected into the geological formation during the reporting year, and estimates of fugitive emissions to the atmosphere determined in accordance with subsection (3).

(2) For the factor $\boldsymbol{C_{ost}}$ in subsection (1), the opening stock of a greenhouse gas in the storage site for the reporting year is:

(a) for the first reporting year in which this method is used to calculate fugitive emissions—zero; and

(b) for each reporting year other than the first reporting year—the closing stock of a greenhouse gas in the storage site for the previous reporting year, determined in accordance with subsection (1).

(3) For the factor $\boldsymbol{E_{CO_2}}$, fugitive emissions to the atmosphere from geological formations used for the permanent storage of a greenhouse gas are to be estimated from data obtained for monitoring and verification obligations under a licence, lease or approval mentioned in section 1.19A (meaning of ***captured for permanent storage***).

Chapter 4—Industrial processes emissions

Part 4.1—Preliminary

4.1 Outline of Chapter

(1) This Chapter provides for emissions from:
- (a) the consumption of carbonates; or
- (b) the use of fuels as:
  - (i) feedstock; or
  - (ii) carbon reductants;

from sources that are industrial processes mentioned in subsection (2).

(2) For subsection (1), the industrial processes are as follows:
- (a) in Part 4.2:
  - (i) producing cement clinker (see Division 4.2.1);
  - (ii) producing lime (see Division 4.2.2);
  - (iii) using carbonate for the production of a product other than cement clinker, lime or soda ash (see Division 4.2.3);
  - (iv) using and producing soda ash (see Division 4.2.4);
- (b) in Part 4.3—the production of:
  - (i) ammonia (see Division 4.3.1);
  - (ii) nitric acid (see Division 4.3.2);
  - (iii) adipic acid (see Division 4.3.3);
  - (iv) carbide (see Division 4.3.4);
  - (v) a chemical or mineral product other than carbide using a carbon reductant or carbon anode (see Division 4.3.5);
  - (vi) sodium cyanide (see Division 4.3.6);
- (c) in Part 4.4—the production of:
  - (i) iron and steel (see Division 4.4.1);
  - (ii) ferroalloy metals (see Division 4.4.2);
  - (iii) aluminium (see Divisions 4.4.3 and 4.4.4);
  - (iv) other metals (see Division 4.4.5).

(3) This Chapter, in Part 4.5, also applies to emissions released from the consumption of the following synthetic gases:
- (a) hydrofluorocarbons;
- (b) sulphur hexafluoride.

(4) This Chapter does not apply to emissions from fuel combusted for energy production.

Part 4.2—Industrial processes—mineral products

Division 4.2.1—Cement clinker production

4.2 Application

This Division applies to cement clinker production.

4.3 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of carbon dioxide released during a year from the operation of a facility that is constituted by the production of cement clinker:

(a) method 1 under section 4.4;
(b) method 2 under section 4.5;
(c) method 3 under section 4.8;
(d) method 4 under Part 1.3.

(2) However, for incidental emissions, another method may be used that is consistent with the principles in section 1.13.

4.4 Method 1—cement clinker production

Method 1 is:

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

where:

E_{ij} is the emissions of carbon dioxide (***j***) released from the production of cement clinker (***i***) during the year measured in CO_2-e tonnes.

EF_{ij} is 0.534, which is the carbon dioxide (***j***) emission factor for cement clinker (***i***), measured in tonnes of emissions of carbon dioxide per tonne of cement clinker produced.

$EF_{toc,j}$ is 0.010, which is the carbon dioxide (***j***) emission factor for carbon-bearing non-fuel raw material, measured in tonnes of emissions of carbon dioxide per tonne of cement clinker produced.

A_i is the quantity of cement clinker (***i***) produced during the year measured in tonnes and estimated under Division 4.2.5.

A_{ckd} is the quantity of cement kiln dust produced as a result of the production of cement clinker during the year, measured in tonnes and estimated under Division 4.2.5.

F_{ckd} is:

(a) the degree of calcination of cement kiln dust produced as a result of the production of cement clinker during the year, expressed as a decimal fraction; or

(b) if the information mentioned in paragraph (a) is not available—the value 1.

4.5 Method 2—cement clinker production

(1) Method 2 is:

$$E_{ij} = \left(EF_{ij} + EF_{toc,j}\right) \times \left(A_i + A_{ckd} \times F_{ckd}\right) - \gamma RCCS_{co_2}$$

where:

E_{ij} is the emissions of carbon dioxide (***j***) released from the production of cement clinker (***i***) during the year measured in CO_2-e tonnes.

EF_{ij} is as set out in subsection (2).

$EF_{toc,j}$ is 0.010, which is the carbon dioxide (***j***) emission factor for carbon-bearing non-fuel raw material, measured in tonnes of emissions of carbon dioxide per tonne of cement clinker produced.

A_i is the quantity of cement clinker (***i***) produced during the year measured in tonnes and estimated under Division 4.2.5.

A_{ckd} is the quantity of cement kiln dust produced as a result of the production of cement clinker during the year, measured in tonnes and estimated under Division 4.2.5.

F_{ckd} is:

(a) the degree of calcination of cement kiln dust produced as a result of the production of cement clinker during the year, expressed as a decimal fraction; or

(b) if the information mentioned in paragraph (a) is not available—the value 1.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

(2) For subsection (1), EF_{ij} is:

$$F_{CaO} \times 0.785 + F_{MgO} \times 1.092$$

where:

F_{CaO} is the estimated fraction of cement clinker that is calcium oxide derived from carbonate sources and produced from the operation of the facility.

F_{MgO} is the estimated fraction of cement clinker that is magnesium oxide derived from carbonate sources and produced from the operation of the facility.

Note: The molecular weight ratio of carbon dioxide to calcium oxide is 0.785, and the molecular weight ratio of carbon dioxide to magnesium oxide is 1.092.

(3) The cement clinker must be sampled and analysed in accordance with sections 4.6 and 4.7.

4.6 General requirements for sampling cement clinker

(1) A sample of cement clinker must be derived from a composite of amounts of the cement clinker produced.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard.

Note: An appropriate standard is AS 4264.4—1996, *Coal and coke – Sampling* Part 4: *Determination of precision and bias*.

(5) The value obtained from the sample must only be used for the production period for which it was intended to be representative.

4.7 General requirements for analysing cement clinker

(1) Analysis of a sample of cement clinker, including determining the fraction of the sample that is calcium oxide or magnesium oxide, must be done in accordance with industry practice and must be consistent with the principles in section 1.13.

(2) The minimum frequency of analysis of samples of cement clinker must be in accordance with the Tier 3 method for cement clinker in section 2.2.1.1 in Chapter 2 of Volume 3 of the 2006 IPCC Guidelines.

4.8 Method 3—cement clinker production

(1) Method 3 is:

Step 1 Measure the amount of emissions of carbon dioxide in CO_2-e tonnes released from each pure carbonate calcined in the production of cement clinker during the year as follows:

$$E_{ij} = \left(EF_{ij} \times Q_i \times F_{cal}\right) - A_{ckd} \times EF_{ckd} \times \left(1 - F_{ckd}\right) + Q_{toc} \times EF_{toc} - \gamma RCCS_{co_2}$$

where:

E_{ij} is the emissions of carbon dioxide (***j***) released from the carbonate (***i***) calcined in the production of cement clinker during the year measured in CO_2-e tonnes.

EF_{ij} is the carbon dioxide (***j***) emission factor for the carbonate (***i***) measured in tonnes of emissions of carbon dioxide per tonne of pure carbonate, as follows:
(a) for calcium carbonate—0.440; and
(b) for magnesium carbonate—0.522; and
(c) for dolomite—0.477; and
(d) for any other pure carbonate — the factor for the carbonate in accordance with section 2.1 of Chapter 2 of Volume 3 of the 2006 IPCC Guidelines.

Q_i is the quantity of the pure carbonate (***i***) consumed in the calcining process for the production of cement clinker during the year measured in tonnes and estimated under Division 4.2.5.

F_{cal} is:
(a) the amount of the carbonate calcined in the production of cement clinker during the year, expressed as a decimal fraction; or
(b) if the information mentioned in paragraph (a) is not available—the value 1.

A_{ckd} is the quantity of cement kiln dust lost from the kiln in the production of cement clinker during the year measured in tonnes and estimated under Division 4.2.5.

EF_{ckd} is 0.440, which is the carbon dioxide emission factor for calcined cement kiln dust lost from the kiln.

F_{ckd} is:
(a) the fraction of calcination achieved for cement kiln dust lost from the kiln in the production of cement clinker during the year; or
(b) if the information mentioned in paragraph (a) is not available—the value 1.

Q_{toc} is the quantity of total carbon-bearing non-fuel raw material consumed in the production of cement clinker during the year measured in tonnes and estimated under Division 4.2.5.

EF_{toc} is 0.010, which is the emission factor for carbon-bearing non-fuel raw material, measured in tonnes of carbon dioxide produced per tonne of carbon.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

Step 2 Add together the amount of emissions of carbon dioxide as measured in CO_2-e tonnes released for each pure carbonate calcined in the production of cement clinker during the year.

(2) For the factor EF_{ckd} in subsection (1), the carbon dioxide emission factor for calcined cement kiln dust is assumed to be the same as the emission factor for calcium carbonate.

(3) For the factor Q_{toc} in subsection (1), the quantity of carbon-bearing non-fuel raw material must be estimated in accordance with Division 4.2.5 as if a reference to

carbonates consumed from the activity was a reference to carbon-bearing non-fuel raw material consumed from the activity.

(4) Method 3 requires carbonates to be sampled and analysed in accordance with sections 4.9 and 4.10.

4.9 General requirements for sampling carbonates

(1) Method 3 requires carbonates to be sampled in accordance with the procedure for sampling cement clinker specified under section 4.6 for method 2.

(2) In applying section 4.6, a reference in that section to cement clinker is taken to be a reference to a carbonate.

4.10 General requirements for analysing carbonates

(1) Analysis of samples of carbonates, including determining the quantity (in tonnes) of pure carbonate, must be done in accordance with industry practice or standards, and must be consistent with the principles in section 1.13.

(2) The minimum frequency of analysis of samples of carbonates must be in accordance with the Tier 3 method in section 2.2.1.1 of Chapter 2 of Volume 3 of the 2006 IPCC Guidelines.

Division 4.2.2—Lime production

4.11 Application

This Division applies to lime production (other than the in-house production of lime in the metals industry).

4.12 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of carbon dioxide released during a year from the operation of a facility that is constituted by the production of lime (other than the in-house production of lime in the ferrous metals industry):
  (a) method 1 under section 4.13;
  (b) method 2 under section 4.14;
  (c) method 3 under section 4.17;
  (d) method 4 under Part 1.3.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.13 Method 1—lime production

(1) Method 1 is:

$$E_{ij} = \left(A_i + A_{lkd} \times F_{lkd}\right) \times EF_{ij}$$

where:

E_{ij} is the emissions of carbon dioxide (***j***) released from the production of lime (***i***) during the year, measured in CO_2-e tonnes.

A_i is the quantity of lime produced during the year, measured in tonnes and estimated under Division 4.2.5.

A_{lkd} is the quantity of lime kiln dust lost as a result of the production of lime during the year, measured in tonnes and estimated under Division 4.2.5.

F_{lkd} is:
  (a) the fraction of calcination achieved for lime kiln dust in the production of lime during the year; or
  (b) if the data mentioned in paragraph (a) is not available—the value 1.

EF_{ij} is the carbon dioxide (***j***) emission factor for lime, measured in tonnes of emission of carbon dioxide per tonne of lime produced, as follows:
  (a) for commercial lime production—0.675;
  (b) for non-commercial lime production—0.730;
  (c) for magnesian lime and dolomitic lime production—0.860.

(2) In this section:

dolomitic lime is lime formed from limestone containing more than 35% magnesium carbonate.

magnesian lime is lime formed from limestone containing 5–35% magnesium carbonate.

4.14 Method 2—lime production

(1) Method 2 is:

$$E_{ij} = \left(A_i + A_{lkd} \times F_{lkd}\right) \times EF_{ij} - \gamma RCCS_{co_2}$$

where:

E_{ij} is the emissions of carbon dioxide (***j***) released from the production of lime (***i***) during the year, measured in CO_2-e tonnes.

A_i is the quantity of lime produced during the year, measured in tonnes and estimated under Division 4.2.5.

A_{lkd} is the quantity of lime kiln dust lost as a result of the production of lime during the year, measured in tonnes and estimated under Division 4.2.5.

F_{lkd} is:

(a) the fraction of calcination achieved for lime kiln dust in the production of lime during the year; or

(b) if the data in paragraph (a) is not available—the value 1.

EF_{ij} is worked out using the following formula:

$$EF_{ij} = F_{CaO} \times 0.785 + F_{MgO} \times 1.092$$

where:

F_{CaO} is the estimated fraction of lime that is calcium oxide derived from carbonate sources and produced from the operation of the facility.

F_{MgO} is the estimated fraction of lime that is magnesium oxide derived from carbonate sources and produced from the operation of the facility.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage, measured in cubic metres in accordance with Division 1.2.3.

(2) Method 2 requires lime to be sampled and analysed in accordance with sections 4.15 and 4.16.

4.15 General requirements for sampling

(1) A sample of lime must be derived from a composite of amounts of the lime produced.

Note: Appropriate standards for sampling are:

- ASTM C25-06, *Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime*
- ASTM C50-00 (2006), *Standard Practice for Sampling, Sample Preparation, Packaging, and Marking of Lime and Limestone Products*
- AS 4489.0–1997 *Test methods for limes and limestones—General introduction and list of methods*.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard.

Note: An appropriate standard is AS 4264.4—1996 – *Coal and coke – sampling – Determination of precision and bias*.

(5) The value obtained from the sample must only be used for the production period for which it was intended to be representative.

4.16 General requirements for analysis of lime

(1) Analysis of a sample of lime, including determining the fractional purity of the sample, must be done in accordance with industry practice and must be consistent with the principles in section 1.13.

(2) The minimum frequency of analysis of samples of lime must be in accordance with the Tier 3 method in section 2.2.1.1 of Chapter 2 of Volume 3 of the 2006 IPCC Guidelines.

4.17 Method 3—lime production

(1) Method 3 is:

Step 1 Measure the amount of emissions of carbon dioxide in CO_2-e tonnes released from each pure carbonate calcined in the production of lime during the year as follows:

$$E_{ij} = (EF_{ij} \times Q_i \times F_{cal}) - A_{lkd} \times EF_{lkd} \times (1 - F_{lkd}) - \gamma RCCS_{co_2}$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of carbon dioxide (***j***) released from a carbonate (***i***) calcined in the production of lime during the year measured in CO_2-e tonnes.

EF_{ij} is the carbon dioxide (***j***) emission factor for the carbonate (***i***), measured in tonnes of emissions of carbon dioxide per tonne of pure carbonate as follows:

(a) for calcium carbonate—0.440;

(b) for magnesium carbonate—0.522;

(c) for dolomite—0.477;

(d) for any other carbonate—the factor for the carbonate in accordance with section 2.1 of Chapter 2 of Volume 3 of the 2006 IPCC Guidelines.

Q_i is the quantity of the pure carbonate (***i***) entering the calcining process in the production of lime during the year measured in tonnes and estimated under Division 4.2.5.

F_{cal} is:

(a) the amount of the carbonate calcined in the production of lime during the year expressed as a decimal fraction; or

(b) if the information mentioned in paragraph (a) is not available—the value 1.

A_{lkd} is the quantity of lime kiln dust lost in the production of lime during the year, measured in tonnes and estimated under Division 4.2.5.

EF_{lkd} is 0.440, which is the emission factor for calcined lime kiln dust lost from the kiln.

F_{lkd} is:

(a) the fraction of calcination achieved for lime kiln dust in the production of lime during the year; or

(b) if the data in paragraph (a) is not available—the value 1.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

Step 2 Add together the amount of emissions of carbon dioxide for each pure carbonate calcined in the production of lime during the year.

(2) For the factor EF_{lkd} in subsection (1), the emission factor for calcined lime kiln dust is assumed to be the same as the emission factor for calcium carbonate.

(3) Method 3 requires each carbonate to be sampled and analysed in accordance with sections 4.18 and 4.19.

4.18 General requirements for sampling

(1) For section 4.17, carbonates must be sampled in accordance with the procedure for sampling lime specified under section 4.15 for method 2.

(2) In applying section 4.15, a reference in that section to lime is taken to be a reference to carbonates.

4.19 General requirements for analysis of carbonates

(1) For section 4.17, samples must be analysed in accordance with the procedure for analysing lime specified under section 4.16 for method 2.

(2) In applying section 4.16, a reference in that section to lime is taken to be a reference to carbonates.

Division 4.2.3—Use of carbonates for production of a product other than cement clinker, lime or soda ash

4.20 Application

This Division applies to emissions of carbon dioxide from the consumption of a carbonate (other than soda ash) but does not apply to:

(a) emissions of carbon dioxide from the calcination of a carbonate in the production of cement clinker; or

(b) emissions of carbon dioxide from the calcination of a carbonate in the production of lime; or

(c) emissions of carbon dioxide from the calcination of a carbonate in the process of production of soda ash; or

(d) emissions from the consumption of carbonates following their application to soil.

Examples of activities involving the consumption of carbonates:

1 Metallurgy.
2 Glass manufacture, including fibreglass and mineral wools.
3 Magnesia production.
4 Construction.
5 Environment pollution control.
6 Use as a flux or slagging agent.
7 In-house production of lime in the metals industry.
8 Phosphoric acid production from phosphate rock containing carbonates.
9 Brick production.
10 Ceramic production.

4.21 Available methods

(1) Subject to section 1.18 one of the following methods must be used for estimating emissions of carbon dioxide released during a year from the operation of a facility constituted by the calcination or any other use of carbonates that produces carbon dioxide (the ***industrial process***) in an industrial process (other than cement clinker production or lime production):

(a) method 1 under section 4.22;
(aa) for use of carbonates in clay materials—method 1A under section 4.22A;
(b) method 3 under section 4.23;
(ba) for use of carbonates in clay materials—method 3A under section 4.23A;
(c) method 4 under Part 1.3.

Note: There is no method 2 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.22 Method 1—product other than cement clinker, lime or soda ash

Method 1 is:

Step 1 Measure the amount of emissions of carbon dioxide in CO2-e tonnes released from each raw carbonate material consumed in the industrial process during the year as follows:

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

where:

$\boldsymbol{E_{ij}}$ is the emissions of carbon dioxide (***j***) released from raw carbonate material (***i***) consumed in the industrial process during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of the raw carbonate material (***i***) consumed in the calcining process for the industrial process during the year measured in tonnes and estimated under Division 4.2.5.

$\boldsymbol{EF_{ij}}$ is the carbon dioxide (***j***) emission factor for the raw carbonate material (***i***) measured in tonnes of emissions of carbon dioxide per tonne of carbonate, that is:

(a) for calcium carbonate—0.396; and
(b) for magnesium carbonate—0.522; and
(c) for dolomite—0.453; and
(d) for any other raw carbonate material—the factor for the raw carbonate material in accordance with section 2.1 of Chapter 2 of Volume 3 of the 2006 IPCC Guidelines.

$\boldsymbol{F_{cal}}$ is:

(a) the fraction of the raw carbonate material consumed in the industrial process during the year; or
(b) if the information in paragraph (a) is not available—the value 1.

Step 2 Add together the amount of emissions of carbon dioxide for each carbonate consumed in the industrial process during the year.

Note: For the factor ***Efij*** in step 1, the emission factor value given for a raw carbonate material is based on a method of calculation that ascribed the following content to the material:
(a) for calcium carbonate—at least 90% calcium carbonate;
(b) for magnesium carbonate—100% magnesium carbonate;
(c) for dolomite—at least 95% dolomite.

4.22A Method 1A—product other than cement clinker, lime or soda ash for use of carbonates in clay materials

(1) Method 1A is measure the amount of emissions of carbon dioxide released from each clay material consumed in the industrial process during the reporting year, measured in CO_2-e tonnes, using the following formula:

$$E_j = Q_j \times ICC_j \times 3.664$$

where:

E_j is the emissions of carbon dioxide released from the clay material consumed in the industrial process during the reporting year in a State or Territory (***j***) mentioned in column 2 of an item in the table in subsection (2), measured in CO_2-e tonnes.

Q_j is the quantity of clay material consumed in the industrial process during the reporting year in a State or Territory (***j***) mentioned in column 2 of an item in the table in subsection (2), measured in tonnes and estimated under Division 4.2.5.

ICC_j is the inorganic carbon content factor of clay material specified in column 3 of an item in the table in subsection (2) for each State or Territory (***j***) mentioned in column 2 of the item.

(2) For ***ICC_j*** in subsection (1), column 3 of an item in the following table specifies the inorganic carbon content factor for a State or Territory (***j***) mentioned in column 2 of the item.

Item	State or Territory (j)	Inorganic carbon content factor
1	New South Wales	6.068×10^{-3}
2	Victoria	2.333×10^{-4}
3	Queensland	2.509×10^{-3}
4	Western Australia	3.140×10^{-4}
5	South Australia	5.170×10^{-4}
6	Tasmania	1.050×10^{-3}
7	Australian Capital Territory	6.068×10^{-3}
8	Northern Territory	5.170×10^{-4}

4.23 Method 3—product other than cement clinker, lime or soda ash

(1) Method 3 is:

Step 1 Measure the amount of emissions of carbon dioxide in CO2-e tonnes released from each pure carbonate consumed in the industrial process during the year as follows:

$$E_{ij} = EF_{ij} \times Q_i \times F_{cal} - \gamma RCCS_{co_2}$$

where:

E_{ij} is the emissions of carbon dioxide (***j***) from a pure carbonate (***i***) consumed in the industrial process during the year measured in CO_2-e tonnes.

EF_{ij} is the carbon dioxide (***j***) emission factor for the pure carbonate (***i***) in tonnes of emissions of carbon dioxide per tonne of pure carbonate, that is:

(a) for calcium carbonate—0.440;
(b) for magnesium carbonate—0.522;
(c) for dolomite—0.477;
(d) for any other pure carbonate—the factor for the carbonate in accordance with Chapter 2 of Volume 3 of the 2006 IPCC Guidelines.

Q_i is the quantity of the pure carbonate (***i***) entering the industrial process during the year measured in tonnes and estimated under Division 4.2.5.

F_{cal} is:

(a) the fraction of the pure carbonate consumed in the industrial process during the year; or
(b) if the information in paragraph (a) is not available—the value 1.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

Step 2 Add together the amount of emissions of carbon dioxide for each pure carbonate consumed in the industrial process during the year.

(2) Method 3 requires each carbonate to be sampled and analysed in accordance with sections 4.24 and 4.25.

4.23A Method 3A—product other than cement clinker, lime or soda ash for use of carbonates in clay materials

Method 3A is:

Step 1 Measure the amount of emissions of carbon dioxide released from each clay material consumed in the industrial process during the reporting year, measured in CO2-e tonnes, using the following formula:

$$E = Q \times ICC \times 3.664 - \gamma \, RCCS_{CO_2}$$

where:

E is the emissions of carbon dioxide released from the clay material consumed in the industrial process during the reporting year, measured in CO_2-e tonnes.

Q is the quantity of clay material consumed in the industrial process during the reporting year, measured in tonnes and estimated under Division 4.2.5.

ICC is the inorganic carbon content factor of the clay material.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$\boldsymbol{RCCS_{CO_2}}$ is carbon dioxide captured for permanent storage, measured in cubic metres in accordance with Division 1.2.3.

Step 2 Identify the amount of emissions of carbon dioxide for each clay material consumed in the industrial process during the reporting year.

Step 3 Add together each amount identified under step 2.

4.23B General requirements for sampling clay material

(1) A sample of clay material must:
  (a) be derived from a composite of amounts of the clay material; and
  (b) be collected on enough occasions to produce a representative sample; and
  (c) be free from bias so that any estimates are neither over nor under estimates of the true value; and
  (d) be tested for bias in accordance with an appropriate standard.

(2) The value obtained from the samples of the clay material must be used only for the delivery period or consignment of the clay material for which it was intended to be representative.

4.23C General requirements for analysing clay material

(1) Analysis of samples of the clay material must be performed in accordance with:
  (a) industry practice; and
  (b) the general principles for measuring emissions mentioned in section 1.13.

(2) The minimum frequency of analysis of samples of clay material must be in accordance with the Tier 3 method in section 2.2.1.1 of Chapter 2 of Volume 3 of the 2006 IPCC Guidelines.

4.24 General requirements for sampling carbonates

(1) A sample of a carbonate must be derived from a composite of amounts of the carbonate consumed.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard.

Note: An example of an appropriate standard is AS 4264.4—1996 – *Coal and coke – sampling – Determination of precision and bias*.

(5) The value obtained from the samples must only be used for the delivery period or consignment of the carbonate for which it was intended to be representative.

4.25 General requirements for analysis of carbonates

(1) Analysis of samples of carbonates must be in accordance with industry practice and must be consistent with the principles in section 1.13.

(2) The minimum frequency of analysis of samples of carbonates must be in accordance with the Tier 3 method of section 2.2.1.1 of Chapter 2 of Volume 3 of the 2006 IPCC Guidelines.

Division 4.2.4—Soda ash use and production

4.26 Application

This Division applies to emissions from the use of soda ash and emissions of carbon dioxide from the chemical transformation of calcium carbonate, sodium chloride, ammonia and coke into sodium bicarbonate and soda ash.

Examples of uses of soda ash in industrial processes:

1 Glass production.
2 Soap and detergent production.
3 Flue gas desulphurisation.
4 Pulp and paper production.

4.27 Outline of Division

Emissions released from the use and production of soda ash must be estimated in accordance with:

(a) for the use of soda ash in production processes—Subdivision 4.2.4.1; or
(b) for the production of soda ash—Subdivision 4.2.4.2.

Subdivision 4.2.4.1—Soda ash use

4.28 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of carbon dioxide released during a year from the operation of a facility constituted by the use of soda ash in a production process:

(a) method 1 under section 4.29;
(b) method 4 under Part 1.3.

Note: There is no method 2 or 3 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.29 Method 1—use of soda ash

Method 1 is:

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

where:

E**$_{ij}$* is the emissions of carbon dioxide (j***) from soda ash (***i***) consumed in the production process during the year measured in CO_2-e tonnes.

Q**$_i$* is the quantity of soda ash (i***) consumed in the production process during the year measured in tonnes and estimated under Division 4.2.5.

EF_{ij} is 0.415, which is the carbon dioxide (***j***) emission factor for soda ash (***i***) measured in tonnes of carbon dioxide emissions per tonne of soda ash.

Subdivision 4.2.4.2—Soda ash production

4.30 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions released during a year from the operation of a facility that is constituted by an activity that produces soda ash:

(a) method 1 under section 4.31;
(b) method 2 under section 4.32;
(c) method 3 under section 4.33;
(d) method 4 under Part 1.3.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.31 Method 1—production of soda ash

Method 1 is:

Step 1 Calculate the carbon content in fuel type (***i***) or carbonate material (***j***) delivered for the activity during the year measured in tonnes of carbon as follows:

$$\Sigma_i\ CCF_i \times Q_i + \Sigma_j\ CCF_j \times F_j \times L_j$$

where:

$\sum_i$ means sum the carbon content values obtained for all fuel types (***i***).

CCF_i is the carbon content factor mentioned in Schedule 3 measured in tonnes of carbon for each appropriate unit of fuel type (i) consumed during the year from the operation of the activity.

Q_i is the quantity of fuel type (***i***) delivered for the activity during the year measured in an appropriate unit and estimated in accordance with Division 2.2.5, 2.3.6 and 2.4.6.

$\sum_j$ means sum the carbon content values obtained for all pure carbonate material (***j***).

CCF_j is the carbon content factor mentioned in Schedule 3 measured in tonnes of carbon for each tonne of pure carbonate material (***j***) consumed during the year from the operation of the activity.

F_j is the fraction of pure carbonate material (***j***) in the raw carbonate input material and taken to be 0.97 for calcium carbonate and 0.018 for magnesium carbonate.

L_j is the quantity of raw carbonate input material (***j***) delivered for the activity during the year measured in tonnes and estimated in accordance with Division 4.2.5.

Step 2 Calculate the carbon content in products (***p***) leaving the activity during the year measured in tonnes of carbon as follows:

$$\sum_p CCF_p \times F_p \times A_p$$

where:

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

CCF_p is the carbon content factor mentioned in Schedule 3 and measured in tonnes of carbon for each tonne of product type (***p***) produced during the year.

F_p is the fraction of pure carbonate material in the product type (***p***).

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:

$$\Sigma_r \, CCF_r \times F_r \times Y_r$$

where:

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

CCF_r is the carbon content factor mentioned in Schedule 3 measured in tonnes of carbon for each tonne of waste by-product types (***r***).

F_r is the fraction of pure carbonate material in the 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 change 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:

$$\Sigma_i \, CCF_i \times \Delta S_{qi} + \Sigma_j \, CCF_j \times \Delta S_{qj} + \Sigma_p \, CCF_p \times \Delta S_{ap} + \Sigma_r \, CCF_r \times \Delta S_{yr}$$

where:

Σ_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

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

Σ_j has the same meaning as in step 1.

CCF_j has the same meaning as in step 1.

ΔS_{qj} is the change in stocks of pure carbonate material (***j***) for the activity and held within the boundary of the activity during the year measured in tonnes.

Σ_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

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

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the change 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 CO_2-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.

4.32 Method 2—production of soda ash

Method 2 is:

Step 1 Calculate the carbon content in fuel types (***i***) or carbonate material (***j***) delivered for the activity during the year measured in tonnes of carbon as follows:

$$\Sigma_i \; CCF_i \times Q_i + \Sigma_j CCF_j \times L_j$$

where:

$\sum_i$ means sum the carbon content values obtained for all fuel types (***i***).

CCF_i is the carbon content factor measured in tonnes of carbon for each appropriate unit of fuel type (***i***) consumed during the year from the operation of the activity.

Q_i is the quantity of fuel type (***i***) delivered for the activity during the year measured in an appropriate unit and estimated in accordance with Divisions 2.2.5, 2.3.6 and 2.4.6.

$\sum_j$ means sum the carbon content values obtained for all pure carbonate material (***j***).

CCF_j is the carbon content factor measured in tonnes of carbon for each pure carbonate material (***j***) consumed during the year from the operation of the activity.

L_j is the quantity of pure carbonate material (***j***) delivered for the activity during the year measured in tonnes and estimated in accordance with Division 4.2.5.

Step 2 Calculate the carbon content in products (p) leaving the activity during the year measured in tonnes of carbon as follows:

$$\Sigma_p \, CCF_p \times A_p$$

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:

Σ_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 change 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:

$$\Sigma_i CCF_i \times \Delta S_{qi} + \Sigma_j CCF_j \times \Delta S_{qj} + \Sigma_p CCF_p \times \Delta S_{ap} + \Sigma_r CCF_r \times \Delta S_{yr} + \alpha\gamma RCCS_{CO_2}$$

where:

Σ_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

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

Σ_j has the same meaning as in step 1.

$CCFj$ has the same meaning as in step 1.

ΔS_{qj} is the change in stocks of pure carbonate material (***j***) for the activity and held within the boundary of the activity during the year measured in tonnes.

Σ_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

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

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

Δs_{yr} is the change 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.

α is the factor $\frac{1}{3.664}$ for converting the mass of carbon dioxide to a mass of carbon.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

Step 5 Calculate the emissions of carbon dioxide released from the operation of the activity during the year measured in CO_2-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.

(2) If a fuel type (***i***) or carbonate material (***j***) delivered for the activity during the year accounts for more than 5% of total carbon input for the activity based on a calculation using the factors mentioned in Schedule 3, sampling and analysis of fuel type ***(i)*** or carbonate material (***j***) must be carried out to determine its carbon content.

(3) The sampling and analysis for fuel type (***i***) is to be carried out using the sampling and analysis provided for in Divisions 2.2.3, 2.3.3 and 2.4.3.

(4) The sampling for carbonate materials (***j***) is to be carried out in accordance with section 4.24.

(5) The analysis for carbonate materials (***j***) is to be carried out in accordance with ASTM C25-06, *Standard Test Methods for Chemical Analysis of Limestone, Quicklime, and Hydrated Lime* or an equivalent standard.

4.33 Method 3—production of soda ash

(1) Subject to subsections (2) and (3), method 3 is the same as method 2.

(2) The sampling and analysis for fuel type (***i***) is to be carried out using the sampling and analysis provided for in Divisions 2.2.4, 2.3.4 and 2.4.4 or an equivalent sampling and analysis method.

(3) The sampling for carbonate material (**j**) is to be carried out in accordance with ASTM C50-00 (2006), *Standard Practice for Sampling, Sample Preparation, Packaging, and Marking of Lime and Limestone Products*.

Division 4.2.5—Measurement of quantity of carbonates consumed and products derived from carbonates

4.34 Purpose of Division

(1) This Division applies to the operation of a facility (the ***activity***) that is constituted by:
   (a) the production of cement clinker; or
   (b) the production of lime; or
   (c) the calcination of carbonates in an industrial process; or
   (d) the use and production of soda ash.

(2) This Division sets out how the quantities of carbonates consumed from the operation of the activity, and the quantities of products derived from carbonates produced from the operation of the activity, are to be estimated for the following:
   (a) Ai and Ackd in section 4.4;
   (b) Qi and Qtoc in section 4.8;
   (c) Ai in section 4.13;
   (d) Qi and Alkd in section 4.17;
   (e) Qj in sections 4.22, 4.22A, 4.23, 4.29, 4.55, 4.66, 4.71 and 4.94;
   (f) Q in section 4.23A;
   (g) Lj in sections 4.31 and 4.32.

4.35 Criteria for measurement

(1) Quantities of carbonates consumed from the operation of the activity, or quantities of products derived from carbonates produced from the operation of the activity, must be estimated in accordance with this section.

Acquisition involves commercial transaction

(2) If the acquisition of the carbonates, or the dispatch of the products derived from carbonates, involves a commercial transaction, the quantity of the carbonates or products must be estimated using one of the following criteria:
   (a) the quantity of the carbonates acquired or products dispatched for the facility during the year as evidenced by invoices issued by the vendor of the carbonates or products (***criterion A***);
   (b) as provided in section 4.36 (***criterion AA***);
   (c) as provided in section 4.37 (***criterion AAA***).

(3) If, during a year, criterion AA, or criterion AAA using paragraph 4.37(2)(a), is used to estimate the quantity of carbonates acquired or products dispatched, then, in each year following that year, only criterion AA, or criterion AAA using paragraph 4.37(2)(a), (respectively) is to be used.

Acquisition does not involve commercial transaction

(4) If the acquisition of the carbonates or the dispatch of the products does not involve a commercial transaction, the quantity the carbonates or products must be estimated using one of the following criteria:

(a) as provided in paragraph 4.37(2)(a) (***criterion AAA***);

(b) as provided in section 4.38 (***criterion BBB***).

4.36 Indirect measurement at point of consumption or production—criterion AA

(1) For paragraph 4.35(b), criterion AA is the amount of carbonates consumed from the operation of the activity, or the amount of products derived from carbonates produced from the operation of the activity, during the year based on amounts delivered or dispatched during the year:

(a) as evidenced by invoices; and

(b) as adjusted for the estimated change in the quantity of the stockpiles of carbonates or the quantity of the stockpiles of products derived from carbonates during the year.

(2) The volume of carbonates, or products derived from carbonates, in the stockpile for the activity must be measured in accordance with industry practice.

4.37 Direct measurement at point of consumption or production—criterion AAA

(1) For paragraph 4.35(c), criterion AAA is the direct measurement during the year of:

(a) the quantities of carbonates consumed from the operation of the activity; or

(b) the quantities of products derived from carbonates produced from the operation of the activity.

(2) The measurement must be:

(a) carried out using measuring equipment calibrated to a measurement requirement; or

(b) for measurement of the quantities of carbonates consumed from the operation of the activity—carried out at the point of sale using measuring equipment calibrated to a measurement requirement.

(3) Paragraph (2)(b) only applies if:

(a) the change in the stockpile of the carbonates for the activity during the year is less than 1% of total consumption of the carbonates from the operation of the activity on average during the year; and

(b) the stockpile of the carbonates for the activity at the beginning of the year is less than 5% of total consumption of the carbonates from the operation of the activity during the year.

4.38 Acquisition or use or disposal without commercial transaction—criterion BBB

For paragraph 4.35(d), criterion BBB is the estimation of the consumption of carbonates, or the products derived from carbonates, during the year in accordance with industry practice if the equipment used to measure consumption of the carbonates, or the products derived from carbonates, is not calibrated to a measurement requirement.

4.39 Units of measurement

Measurements of carbonates and products derived from carbonates must be converted to units of tonnes.

Part 4.3—Industrial processes—chemical industry

Division 4.3.1—Ammonia production

4.40 Application

This Division applies to chemical industry ammonia production.

4.41 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions released during a year from the operation of a facility that is constituted by the production of ammonia:
  (a) method 1 under section 4.42;
  (b) method 2 under section 4.43;
  (c) method 3 under section 4.44;
  (d) method 4 under Part 1.3.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.42 Method 1—ammonia production

(1) Method 1 is:

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

where:

$\boldsymbol{E_{ij}}$ is the emissions of carbon dioxide released from the production of ammonia during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of each type of feedstock or type of fuel (***i***) consumed from the production of ammonia during the year, measured in the appropriate unit and estimated using a criterion in Division 2.3.6.

$\boldsymbol{EC_i}$ is the energy content factor for fuel type ***(i)*** used as a feedstock in the production of ammonia during the year, estimated under section 6.5.

$\boldsymbol{EF_{ij}}$ is the carbon dioxide emission factor for each type of feedstock or type of fuel (***i***) used in the production of ammonia during the year, including the effects of oxidation, measured in kilograms for each gigajoule according to source as mentioned in Part 2 of Schedule 1.

R is the quantity of carbon dioxide measured in tonnes derived from the production of ammonia during the year, captured and transferred for use in the operation of another facility, estimated using an applicable criterion in Division 2.3.6 and in accordance with any other requirements of that Division.

(2) For the purposes of calculating ***R*** in subsection (1), if:

(a) more than one fuel is consumed in the production of ammonia; and

(b) the carbon dioxide generated from the production of ammonia is captured and transferred for use in the operation of another facility or captured for permanent storage;

the total amount of carbon dioxide that may be deducted in relation to the production of ammonia is to be attributed to each fuel consumed in proportion to the carbon content of the fuel relative to the total carbon content of all fuel consumed in the production of ammonia.

4.43 Method 2—ammonia production

(1) Method 2 is:

$$E_{ij} = \frac{Q_i \times EC_i \times EF_{ij}}{1\ 000} - R - \gamma RCCS_{co_2}$$

where:

$\boldsymbol{E_{ij}}$ is the emissions of carbon dioxide released from the production of ammonia during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of each type of feedstock or type of fuel (***i***) consumed from the production of ammonia during the year, measured in the appropriate unit and estimated using an applicable criterion in Division 2.3.6.

$\boldsymbol{EC_i}$ is the energy content factor for fuel type ***(i)*** used as a feedstock in the production of ammonia during the year, estimated under section 6.5.

$\boldsymbol{EF_{ij}}$ is the carbon dioxide emission factor for each type of feedstock or type of fuel (***i***) used in the production of ammonia during the year, including the effects of oxidation, measured in kilograms for each gigajoule according to source in accordance with subsection (2).

R is the quantity of carbon dioxide measured in tonnes derived from the production of ammonia during the year, captured and transferred for use in the operation of another facility, estimated using an applicable criterion in Division 2.3.6 and in accordance with any other requirements of that Division.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$\boldsymbol{RCCS_{CO_2}}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

(2) The method for estimating emission factors for gaseous fuels in Division 2.3.3 applies for working out the factor $\boldsymbol{EF_{ij}}$.

(3) For the purposes of calculating ***R*** in subsection (1), if:

(a) more than one fuel is consumed in the production of ammonia; and

(b) the carbon dioxide generated from the production of ammonia is captured and transferred for use in the operation of another facility or captured for permanent storage;

the total amount of carbon dioxide that may be deducted in relation to the production of ammonia is to be attributed to each fuel consumed in proportion to the carbon content of the fuel relative to the total carbon content of all fuel consumed in the production of ammonia.

4.44 Method 3—ammonia production

(1) Method 3 is the same as method 2 under section 4.43.

(2) In applying method 2 as method 3, the method for estimating emission factors for gaseous fuels in Division 2.3.4 applies for working out the factor $\boldsymbol{EF_{ij}}$.

Division 4.3.2—Nitric acid production

4.45 Application

This Division applies to chemical industry nitric acid production.

4.46 Available methods

(1) Subject to section 1.18 and this section, one of the following methods must be used for estimating emissions during a year from the operation of a facility that is constituted by the production of nitric acid at a plant:

- (a) method 1 under section 4.47;
- (b) method 2 under section 4.48;
- (c) method 4 under Part 1.3.

Note: There is no method 3 for this Division.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

(3) Method 1 must not be used if the plant has used measures to reduce nitrous oxide emissions.

4.47 Method 1—nitric acid production

(1) Method 1 is:

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

where:

$\boldsymbol{E_{ijk}}$ is the emissions of nitrous oxide released during the year from the production of nitric acid at plant type (***k***) measured in CO_2-e tonnes.

$\boldsymbol{EF_{ijk}}$ is the emission factor of nitrous oxide for each tonne of nitric acid produced during the year from plant type (***k***).

$\boldsymbol{A_{ik}}$ is the quantity, measured in tonnes, of nitric acid produced during the year from plant type (***k***).

(2) For $\boldsymbol{EF_{ijk}}$ in subsection (1), column 3 of an item in the following table specifies the emission factor of nitrous oxide for each tonne of nitric acid produced from a plant type (***k***) specified in column 2 of that item.

Item	Plant type (*k*)	Emission factor of nitrous oxide (tonnes CO_2-e per tonne of nitric acid production)
1	Atmospheric pressure plants	1.49
2	Medium pressure combustion plant	2.09

Item	**Plant type (*k*)**	**Emission factor of nitrous oxide (tonnes CO_2-e per tonne of nitric acid production)**
3	High pressure plant	2.68

Note: The emission factors specified in this table apply only to method 1 and the operation of a facility that is constituted by a plant that has not used measures to reduce nitrous oxide emissions.

4.48 Method 2—nitric acid production

(1) Subject to this section, method 2 is the same as method 1 under section 4.47.

(2) In applying method 1 under section 4.47, to work out the factor $\boldsymbol{EF_{ijk}}$:

(a) periodic emissions monitoring must be used and conducted in accordance with Part 1.3; and

(b) the emission factor must be measured as nitrous oxide in CO_2-e tonnes for each tonne of nitric acid produced during the year from the plant.

(3) For method 2, all data on nitrous oxide concentrations, volumetric flow rates and nitric acid production for each sampling period must be used to estimate the flow-weighted average emission rate of nitrous oxide for each unit of nitric acid produced from the plant.

Division 4.3.3—Adipic acid production

4.49 Application

This Division applies to chemical industry adipic acid production.

4.50 Available methods

(1) Subject to section 1.18, one of the methods for measuring emissions released in the production of adipic acid set out in section 3.4 of the 2006 IPCC Guidelines must be used for estimating emissions during a year from the operation of a facility that is constituted by the production of adipic acid.

(2) For incidental emissions another method may be used that is consistent with the principles in section 1.13.

Division 4.3.4—Carbide production

4.51 Application

This Division applies to chemical industry carbide production.

4.52 Available methods

(1) Subject to section 1.18, one of the methods for measuring emissions from carbide production set out in section 3.6 of the 2006 IPCC Guidelines must be used for estimating emissions during a year from the operation of a facility that is constituted by carbide production.

(2) For incidental emissions another method may be used that is consistent with the principles in section 1.13.

Division 4.3.5—Chemical or mineral production, other than carbide production, using a carbon reductant or carbon anode

4.53 Application

This Division applies to emissions of carbon dioxide from activities producing a chemical or mineral product (other than carbide production), using a carbon reductant or carbon anode, including the following products:

(a) fused alumina;
(b) fused magnesia;
(c) fused zirconia;
(d) glass;
(e) synthetic rutile;
(f) titanium dioxide.

Note: Magnesia produced in a process that does not use an electric arc furnace must be reported under Division 4.2.3.

4.54 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions released during a year from the operation of a facility that is constituted by the production of a chemical or mineral product:

(a) method 1 under section 4.55;
(b) method 2 under section 4.56;
(c) method 3 under section 4.57;
(d) method 4 under Part 1.3.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.55 Method 1—chemical or mineral production, other than carbide production, using a carbon reductant or carbon anode

Method 1 is:

Step 1 Work out 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:

$$\Sigma_i \ CCF_i \times Q_i$$

where:

Σ_i means the sum of the carbon content values obtained for all fuel types (***i***) or carbonaceous input material.

CCF_i is the carbon content factor mentioned in Schedule 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 and estimated in accordance with criterion A in Divisions 2.2.5, 2.3.6, 2.4.6 and 4.2.5.

Step 2 Work out the carbon content in products (***p***) leaving the activity during the year, measured in tonnes of carbon, as follows:

$$\Sigma_p \; CCF_p \times A_p$$

where:

Σ_p means the sum of 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 Work out 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:

$$\Sigma_r \; CCF_r \times Y_r$$

where:

Σ_r means the sum of 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 Work out the carbon content in the amount of the change in stocks of inputs, products and waste by-products held within the boundary of the activity during the year, measured in tonnes of carbon, as follows:

$$\Sigma_i \; CCF_i \times \Delta S_{qi} + \Sigma_p \; CCF_p \times \Delta S_{ap} + \Sigma_r \; CCF_r \times \Delta S_{yr}$$

where:

Σ_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

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

Σ_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

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

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the change 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 Work out the emissions of carbon dioxide released from the operation of the activity during the year, measured in CO_2-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 the year.

4.56 Method 2—chemical or mineral production, other than carbide production, using a carbon reductant or carbon anode

(1) Subject to this section, method 2 is the same as method 1 under section 4.55.

(2) In applying method 1 as method 2, step 4 in section 4.55 is to be omitted and the following step 4 substituted.

Step 4 Work out the carbon content in the amount of the change in stocks of inputs, products and waste by-products held within the boundary of the activity during the year, measured in tonnes of carbon, as follows:

$$\Sigma_i \ CCF_i \times \Delta S_{qi} + \Sigma_p \ CCF_p \times \Delta S_{ap} + \Sigma_r \ CCF_r \times \Delta S_{yr} + \alpha \ \gamma RCCS_{co_2}$$

where:

Σ_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

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

Σ_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

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

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the change 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.

α is the factor $\frac{1}{3.664}$ for converting the mass of carbon dioxide to a mass of carbon.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage, measured in cubic metres in accordance with Division 1.2.3.

(3) If a fuel type (***i***) or carbonaceous input material delivered for the activity during the year accounts for more than 5% of total carbon input for the activity, based on a calculation using the factors specified in Schedule 3, sampling and analysis of fuel type ***(i)*** or carbonaceous input material must be carried out to determine its carbon content.

(4) The sampling and analysis is to be carried out using the sampling and analysis provided for in Divisions 2.2.3, 2.3.3 and 2.4.3 that apply to the combustion of solid, gaseous and liquid fuels.

4.57 Method 3—chemical or mineral production, other than carbide production, using a carbon reductant or carbon anode

(1) Subject to this section, method 3 is the same as method 2 under section 4.56.

(2) If a fuel type (***i***) or carbonaceous input material delivered for the activity during the year accounts for more than 5% of total carbon input for the activity, based on a calculation using the factors specified in Schedule 3, sampling and analysis of fuel type ***(i)*** or carbonaceous input material must be carried out to determine its carbon content.

(3) The sampling and analysis is to be carried out using the methods set out in Divisions 2.2.4, 2.3.4 and 2.4.4 that apply to the combustion of solid, gaseous and liquid fuels.

Division 4.3.6—Sodium cyanide production

4.58 Application

This Division applies to emissions of carbon dioxide or nitrous oxide from activities producing sodium cyanide.

4.59 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions released during a reporting year from the operation of a facility that is constituted by the production of sodium cyanide:

  (a) method 1 under section 4.55;
  (b) method 2 under section 4.56;
  (c) method 3 under section 4.57;
  (d) method 4 under Part 1.3.

(2) For estimating incidental emissions released during a reporting year from the operation of a facility that is constituted by the production of sodium cyanide, another method may be used that is consistent with the principles mentioned in section 1.13.

Part 4.4—Industrial processes—metal industry

Division 4.4.1—Iron, steel or other metal production using an integrated metalworks

4.63 Application

This Division applies to emissions from production of the following:
- (a) iron;
- (b) steel;
- (c) any metals produced using integrated metalworks.

4.64 Purpose of Division

(1) This Division applies to determining emissions released during a year from the operation of a facility that is constituted by an activity that produces a metal, for example, an integrated metalworks.

(2) An ***integrated metalworks*** means a metalworks that produces coke and a metal (for example, iron or steel).

(3) The emissions from the activity are to be worked out as a total of emissions released from the production of a metal and from all other emissions released from the operation of the activity (including the production of coke if the activity is an integrated metalworks).

(4) However, the amount of emissions to be determined for this source is only the amount of emissions from the use of coke as a carbon reductant in the metal production estimated in accordance with section 2.69.

Note: The amount of emissions to be determined for other activities is as provided for in other provisions of this Determination.

4.65 Available methods for production of a metal from an integrated metalworks

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions released from the activity during a year:
- (a) method 1 under section 4.66;
- (b) method 2 under section 4.67;
- (c) method 3 under section 4.68;
- (d) method 4 under Part 1.3.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.66 Method 1—production of a metal from an integrated metalworks

Method 1, based on a carbon mass balance approach, is:

Step 1 Calculate the carbon content in fuel types (***i***) and carbonaceous input materials (***i***) delivered for the activity during the year measured in tonnes of carbon as follows:

$$\sum_i CCF_i \times Q_i$$

where:

Σ_i means sum the carbon content values obtained for all fuel types (***i***) and carbonaceous input materials (***i***).

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

Qi is the quantity of fuel type (i) or carbonaceous input material (i) delivered for the activity during the year measured in an appropriate unit and estimated in accordance with:

(a) criterion A in Divisions 2.2.5, 2.3.6, 2.4.6 and 4.2.5; or

(b) if the quantity of fuel or carbonaceous input material is not acquired as part of a commercial transaction—industry practice, consistent with the principles in section 1.13.

Step 2 Calculate the carbon content in products (***p***) leaving the activity during the year measured in tonnes of carbon as follows:

$$\Sigma_p CCF_p \times A_p$$

where:

Σ_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:

$$\Sigma_r CCF_r \times Y_r$$

where:

Σ_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 change 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:

$$\Sigma_i CCF_i \times \Delta S_{qi} + \Sigma_p CCF_p \times \Delta S_{ap} + \Sigma_r CCF_r \times \Delta S_{yr}$$

where:

Σ_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

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

Σ_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

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

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the change 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 CO_2-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.

4.67 Method 2—production of a metal from an integrated metalworks

(1) Subject to this section, method 2 is the same as method 1 under section 4.66.

(1A) In applying method 1 as method 2, step 4 in section 4.66 is to be omitted and the following step 4 substituted.

Step 4 Calculate the carbon content in the amount of the change 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:

$$\Sigma_i \ CCF_i \times \Delta S_{qi} + \Sigma_p \ CCF_p \times \Delta S_{ap} + \Sigma_r \ CCF_r \times \Delta S_{yr} + \alpha \ \gamma RCCS_{co_2}$$

where:

Σ_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

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

Σ_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

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

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the change 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.

α is the factor $\frac{1}{3.664}$ for converting the mass of carbon dioxide to a mass of carbon.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage measured in cubic metres in accordance with Division 1.2.3.

(2) If a fuel type (***i***) or carbonaceous input material delivered for the activity during the year accounts for more than 5% of total carbon input for the activity based on a calculation using the factors specified in Schedule 3, sampling and analysis of fuel type ***(i)*** or carbonaceous input material must be carried out to determine its carbon content.

(3) The sampling and analysis is to be carried out using the sampling and analysis provided for in Divisions 2.2.3, 2.3.3 and 2.4.3 that apply to the combustion of solid, liquid or gaseous fuels.

4.68 Method 3—production of a metal from an integrated metalworks

(1) Subject to this section, method 3 is the same as method 2 under section 4.67.

(2) If a fuel type (***i***) or carbonaceous input material delivered for the activity during the year accounts for more than 5% of total carbon input for the activity based on a calculation using the factors specified in Schedule 3, sampling and analysis of fuel type ***(i)*** or carbonaceous input material must be carried out to determine its carbon content.

(3) The sampling and analysis is to be carried out using the methods set out in Divisions 2.2.4, 2.3.4 and 2.4.4 that apply to the combustion of solid, liquid or gaseous fuels:

Division 4.4.2—Ferroalloys production

4.69 Application

(1) This Division applies to emissions of carbon dioxide from any of the following:
- (a) the consumption of a fossil fuel reductant during the production of:
  - (i) a ferroalloy; or
  - (ii) silicomanganese; or
  - (iii) silicon;
- (b) the oxidation of a fossil fuel electrode in the production of:
  - (i) a ferroalloy; or
  - (ii) silicomanganese; or
  - (iii) silicon.

(2) In this section:

ferroalloy means an alloy of 1 or more elements with iron including, but not limited to, any of the following:
- (a) ferrochrome;
- (b) ferromanganese;
- (c) ferromolybdenum;
- (d) ferronickel;
- (e) ferrosilicon;
- (f) ferrotitanium;
- (g) ferrotungsten;
- (h) ferrovanadium.

4.70 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of carbon dioxide during a year from the operation of a facility that is constituted by the production of ferroalloy metal, silicomanganese or silicon:
- (a) method 1 under section 4.71;
- (b) method 2 under section 4.72;
- (c) method 3 under section 4.73;
- (d) method 4 under Part 1.3.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.71 Method 1—ferroalloy metal

Method 1, based on a carbon mass balance approach, is:

Step 1 Work out 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:

$$\Sigma_i \; CCF_i \times Q_i$$

where:

$\boldsymbol{\Sigma_i}$ means the sum of the carbon content values obtained for all fuel types (***i***) or carbonaceous input material.

$\boldsymbol{CCF_i}$ is the carbon content factor mentioned in Schedule 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.

$\boldsymbol{Q_i}$ is the quantity of fuel type (***i***) or carbonaceous input material delivered for the activity during the year, measured in an appropriate unit and estimated in accordance with:

(a) criterion A in Divisions 2.2.5, 2.3.6, 2.4.6 and 4.2.5; or

(b) if the quantity of fuel or carbonaceous input material is not acquired as part of a commercial transaction — industry practice, consistent with the principles in section 1.13.

Step 2 Work out the carbon content in products (***p***) leaving the activity during the year, measured in tonnes of carbon, as follows:

$$\Sigma_p \; CCF_p \times A_p$$

where:

$\boldsymbol{\Sigma_p}$ means the sum of the carbon content values obtained for all product types (***p***).

$\boldsymbol{CCF_p}$ is the carbon content factor, measured in tonnes of carbon, for each tonne of product type (***p***) produced during the year.

$\boldsymbol{A_p}$ is the quantity of product types (***p***) produced leaving the activity during the year, measured in tonnes.

Step 3 Work out 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:

$$\Sigma_r \; CCF_r \times Y_r$$

where:

$\boldsymbol{\Sigma_r}$ means the sum of the carbon content values obtained for all waste by-product types (***r***).

$\boldsymbol{CCF_r}$ is the carbon content factor, measured in tonnes of carbon, for each tonne of waste by-product types (***r***).

$\boldsymbol{Y_r}$ is the quantity of waste by-product types (***r***) leaving the activity during the year, measured in tonnes.

Step 4 Work out the carbon content in the amount of the change in stocks of inputs, products and waste by-products held within the boundary of the activity during the year, measured in tonnes of carbon, as follows:

$$\Sigma_i\ CCF_i \times \Delta S_{qi} + \Sigma_p\ CCF_p \times \Delta S_{ap} + \Sigma_r\ CCF_r \times \Delta S_{yr}$$

where:

Σ_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

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

Σ_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

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

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the change 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 Work out the emissions of carbon dioxide released from the operation of the activity during the year, measured in CO_2-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 the year.

4.72 Method 2—ferroalloy metal

(1) Subject to this section, method 2 is the same as method 1 under section 4.71.

(2) In applying method 1 as method 2, step 4 in section 4.71 is to be omitted and the following step 4 substituted.

Step 4 Work out the carbon content in the amount of the change in stocks of inputs, products and waste by-products held within the boundary of the activity during the year, measured in tonnes of carbon, as follows:

$$\Sigma_i\ CCF_i \times \Delta S_{qi} + \Sigma_p\ CCF_p \times \Delta S_{ap} + \Sigma_r\ CCF_r \times \Delta S_{yr} + \alpha\ \gamma RCCS_{co_2}$$

where:

Σ_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

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

Σ_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

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

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the change 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.

α is the factor $\frac{1}{3.664}$ for converting the mass of carbon dioxide to a mass of carbon.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage, measured in cubic metres in accordance with Division 1.2.3.

(3) If a fuel type (***i***) or carbonaceous input material delivered for the activity during the year accounts for more than 5% of total carbon input for the activity, based on a calculation using the factors specified in Schedule 3, sampling and analysis of fuel type (***i***) or carbonaceous input material must be carried out to determine its carbon content.

(4) The sampling and analysis is to be carried out using the sampling and analysis provided for in Divisions 2.2.3, 2.3.3 and 2.4.3 that apply to the combustion of solid, gaseous and liquid fuels.

4.73 Method 3—ferroalloy metal

(1) Subject to this section, method 3 is the same as method 2 under section 4.72.

(2) If a fuel type (***i***) or carbonaceous input material delivered for the activity during the year accounts for more than 5% of total carbon input for the activity, based on a calculation using the factors specified in Schedule 3, sampling and analysis of fuel type (***i***) or carbonaceous input material must be carried out to determine its carbon content.

(3) The sampling and analysis is to be carried out using the methods set out in Divisions 2.2.4, 2.3.4 and 2.4.4 that apply to the combustion of solid, gaseous and liquid fuels.

Division 4.4.3—Aluminium production (carbon dioxide emissions)

4.74 Application

This Division applies to aluminium production.

Sudivision 4.4.3.1—Aluminium—emissions from consumption of carbon anodes in aluminium production

4.75 Available methods

(1) Subject to section 1.18, for estimating emissions of carbon dioxide released during a year from the operation of a facility that is constituted by the production of aluminium involving the consumption of carbon anodes, one of the following methods must be used:

- (a) method 1 under section 4.76;
- (b) method 2 under section 4.77;
- (c) method 3 under section 4.78;
- (d) method 4 under Part 1.3.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.76 Method 1—aluminium (carbon anode consumption)

Method 1 is:

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

where:

E_{ij} is the emissions of carbon dioxide released from aluminium smelting and production involving the consumption of carbon anodes during the year measured in CO_2-e tonnes.

A_i is the amount of primary aluminium produced in tonnes during the year.

EF_{ij} is the carbon dioxide emission factor for carbon anode consumption, measured in CO_2-e tonnes for each tonne of aluminium produced during the year, estimated in accordance with the following formula:

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

where:

NAC is the amount of carbon consumed from a carbon anode consumed in the production of aluminium during the year, worked out at the rate of 0.413 tonnes of carbon anode consumed for each tonne of aluminium produced.

S_a is the mass of sulphur content in carbon anodes that is consumed in the production of aluminium during the year, expressed as a percentage of the mass of the carbon anodes, and is taken to be 2.

Ash_a is the mass of ash content in carbon anodes that is consumed in the production of aluminium during the year, expressed as a percentage of the mass of the carbon anodes, and is taken to be 0.4.

4.77 Method 2—aluminium (carbon anode consumption)

(1) Subject to this section, method 2 is the same as method 1 under section 4.76.

(2) In applying method 1 under section 4.76, the method for sampling and analysing the fuel type (i) for the factors NAC, S_a and Ash_a must be determined by sampling and analysing the fuel type for sulphur and ash content, as the case may be, in accordance with:

- (a) for solid fuels—method 2 in Division 2.2.3; and
- (b) for gaseous fuels—method 2 in Division 2.3.3; and
- (c) for liquid fuels—method 2 in Division 2.4.3.

(3) However, in applying method 1 under section 4.76, the factor S_a may be the amount for the factor as mentioned in section 4.76.

(4) If the amount for the factor S_a as mentioned in section 4.76 is not used, then S_a must be determined by sampling and analysing the fuel type (i) for sulphur content in accordance with subsection (2).

4.78 Method 3—aluminium (carbon anode consumption)

(1) Subject to this section, method 3 is the same as method 1 under section 4.76.

(2) In applying method 1 under section 4.76, the method for sampling and analysing fuel type (i) for the factors NAC, S_a and Ash_a must be determined by sampling and analysing the fuel type for sulphur and ash content, as the case may be, in accordance with:

- (a) for solid fuels—method 3 in Division 2.2.4; and
- (b) for gaseous fuels—method 3 in Division 2.3.4; and
- (c) for liquid fuels—method 3 in Division 2.4.4.

Subdivision 4.4.3.2—Aluminium—emissions from production of baked carbon anodes in aluminium production

4.79 Available methods

(1) Subject to section 1.18, for estimating emissions of carbon dioxide released during a year from the operation of a facility that is constituted by the production of aluminium involving the production of baked carbon anodes, one of the following methods must be used:

- (a) method 1 under section 4.80;

(b) method 2 under section 4.81;
(c) method 3 under section 4.82;
(d) method 4 under Part 1.3.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.80 Method 1—aluminium (baked carbon anode production)

Method 1 is:

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

where:

E_{ij} is the emissions of carbon dioxide released from baked carbon anode production for the facility during the year.

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

Hw is the weight of the hydrogen content in green anodes used in the production of the baked carbon anode during the year measured in tonnes.

BA is the amount of baked carbon anode produced during the year measured in tonnes.

WT is the amount, in tonnes, of waste tar collected in the production of baked carbon anodes during the year.

ΣQ_i is the quantity of fuel type (***i***), measured in the appropriate unit, consumed in the production of baked carbon anodes during the year and estimated in accordance with the requirements set out in the following Divisions:

(a) if fuel type (i) is a solid fuel—Division 2.2.5;
(b) if fuel type (i) is a gaseous fuel—Division 2.3.6;
(c) if fuel type (***i***) is a liquid fuel—Division 2.4.6.

S_i is the mass of sulphur content in baked carbon anodes that is consumed in the production of aluminium during the year, expressed as a percentage of the mass of the baked carbon anodes, and is taken to be 2.

Ash_i is the mass of ash content in baked carbon anodes that is consumed in the production of aluminium during the year, expressed as a percentage of the mass of the baked carbon anodes, and is taken to be 0.4.

Note: The default value for ***H_w*** is 0.5% of ***GA***.

4.81 Method 2—aluminium (baked carbon anode production)

(1) Subject to this section, method 2 is the same as method 1 under section 4.80.

(2) In applying method 1 under section 4.80, the method for sampling and analysing fuel type (***i***) for the factors $\boldsymbol{S_i}$ and $\boldsymbol{Ash_i}$ must be determined by sampling and analysing the fuel type for sulphur and ash content, as the case may be, in accordance with:

- (a) for solid fuels—method 2 in Division 2.2.3; and
- (b) for gaseous fuels—method 2 in Division 2.3.3; and
- (c) for liquid fuels—method 2 in Division 2.4.3.

4.82 Method 3—aluminium (baked carbon anode production)

(1) Subject to this section, method 3 is the same as method 1 under section 4.80.

(2) In applying method 1 under section 4.80, the method for sampling and analysing the fuel type (***i***) for the factors $\boldsymbol{S_i}$ and $\boldsymbol{Ash_i}$ must be determined by sampling and analysing the fuel type for sulphur and ash content, as the case may be, in accordance with:

- (a) for solid fuels—method 3 in Division 2.2.4; and
- (b) for gaseous fuels—method 3 in Division 2.3.4; and
- (c) for liquid fuels—method 3 in Division 2.4.4.

Division 4.4.4—Aluminium production (perfluoronated carbon compound emissions)

4.83 Application

This Division applies to aluminium production.

Subdivision 4.4.4.1—Aluminium—emissions of tetrafluoromethane in aluminium production

4.84 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of tetrafluoromethane released during a year from the operation of a facility that is constituted by the production of aluminium:

(b) method 2 under section 4.86;

(c) method 3 under section 4.87.

Note: There is no method 1 or 4 for this provision.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.85 Method 1—aluminium (tetrafluoromethane)

Method 1 is:

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

where:

E_{ij} is the amount of emissions of tetrafluoromethane released from primary aluminium production during the year measured in CO_2-e tonnes.

A_i is the amount of primary aluminium production during the year measured in tonnes.

EF_{ij} is 0.30, which is the emission factor for tetrafluoromethane measured in CO_2-e tonnes for each tonne of aluminium produced during the year.

4.86 Method 2—aluminium (tetrafluoromethane)

Method 2 is the Tier 2 method for estimating perfluorocarbon emissions as set out in the Perfluorocarbon protocol.

4.87 Method 3—aluminium (tetrafluoromethane)

Method 3 is the Tier 3 method for estimating facility-specific perfluorocarbon emissions as set out in the Perfluorocarbon protocol.

Subdivision 4.4.4.2—Aluminium—emissions of hexafluoroethane in aluminium production

4.88 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of hexafluoroethane released during a year from the operation of a facility that is constituted by the production of aluminium:

(b) method 2 under section 4.90;
(c) method 3 under section 4.91.

Note: There is no method 1 or 4 for this provision.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.89 Method 1—aluminium production (hexafluoroethane)

Method 1 is:

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

where:

E_{ij} is the emissions of hexafluoroethane released from primary aluminium production during the year measured in CO_2-e tonnes.

A_i is the amount of primary aluminium production during the year measured in tonnes.

EF_{ij} is 0.07, which is the emission factor for hexafluoroethane measured in CO_2-e tonnes for each tonne of aluminium produced during the year.

4.90 Method 2—aluminium production (hexafluoroethane)

Method 2 is the Tier 2 method for estimating facility-specific perfluorocarbon emissions as set out in the Perfluorocarbon protocol.

4.91 Method 3—aluminium production (hexafluoroethane)

Method 3 is the Tier 3 method for estimating facility-specific perfluorocarbon emissions as set out in the Perfluorocarbon protocol.

Division 4.4.5—Other metals production

4.92 Application

(1) This Division applies to emissions of carbon dioxide from any of the following:
  (a) the consumption of a fossil fuel reductant;
  (b) the oxidation of a fossil fuel electrode.

(2) This Division does not apply to the production of any of the following:
  (a) aluminium;
  (b) ferroalloys;
  (c) iron;
  (d) steel;
  (e) any other metal produced using an integrated metalworks.

4.93 Available methods

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of carbon dioxide from the use of carbon reductants during a year from the operation of a facility that is constituted by the production of metals to which this Division applies:
  (a) method 1 under section 4.94;
  (b) method 2 under section 4.95;
  (c) method 3 under section 4.96;
  (d) method 4 under Part 1.3.

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

4.94 Method 1—other metals

Method 1, based on a carbon mass balance approach, is:

Step 1 Work out 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:

$$\Sigma_i \, CCF_i \times Q_i$$

where:

Σ_i means the sum of the carbon content values obtained for all fuel types (***i***) or carbonaceous input material.

CCF_i is the carbon content factor mentioned in Schedule 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 and estimated in accordance with:

(a) criterion A in Divisions 2.2.5, 2.3.6, 2.4.6 and 4.2.5; or

(b) if the quantity of fuel or carbonaceous input material is not acquired as part of a commercial transaction — industry practice, consistent with the principles in section 1.13.

Step 2 Work out the carbon content in products (***p***) leaving the activity during the year, measured in tonnes of carbon, as follows:

$$\Sigma_p \; CCF_p \times A_p$$

where:

Σ_p means the sum of 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 Work out 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:

$$\Sigma_r \; CCF_r \times Y_r$$

where:

Σ_r means the sum of 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 Work out the carbon content in the amount of the change in stocks of inputs, products and waste by-products held within the boundary of the activity during the year, measured in tonnes of carbon, as follows:

$$\Sigma_i \; CCF_i \times \Delta S_{qi} + \Sigma_p \; CCF_p \times \Delta S_{ap} + \Sigma_r \; CCF_r \times \Delta S_{yr}$$

where:

Σ_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

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

Σ_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

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

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the change 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 Work out the emissions of carbon dioxide released from the operation of the activity during the year, measured in CO_2-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 the year.

4.95 Method 2—other metals

(1) Subject to this section, method 2 is the same as method 1 under section 4.94.

(2) In applying method 1 as method 2, step 4 in section 4.94 is to be omitted and the following step 4 substituted.

Step 4 Work out the carbon content in the amount of the change in stocks of inputs, products and waste by-products held within the boundary of the activity during the year, measured in tonnes of carbon, as follows:

$$\Sigma_i \; CCF_i \times \Delta S_{qi} + \Sigma_p \; CCF_p \times \Delta S_{ap} + \Sigma_r \; CCF_r \times \Delta S_{yr} + \alpha \, \gamma RCCS_{co_2}$$

where:

Σ_i has the same meaning as in step 1.

CCF_i has the same meaning as in step 1.

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

Σ_p has the same meaning as in step 2.

CCF_p has the same meaning as in step 2.

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

Σ_r has the same meaning as in step 3.

CCF_r has the same meaning as in step 3.

ΔS_{yr} is the change 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.

α is the factor $\frac{1}{3.664}$ for converting the mass of carbon dioxide to a mass of carbon.

γ is the factor 1.861×10^{-3} for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes.

$RCCS_{CO_2}$ is carbon dioxide captured for permanent storage, measured in cubic metres in accordance with Division 1.2.3.

(3) If a fuel type (***i***) or carbonaceous input material delivered for the activity during the year accounts for more than 5% of total carbon input for the activity, based on a calculation using the factors specified in Schedule 3, sampling and analysis of fuel type (***i***) or carbonaceous input material must be carried out to determine its carbon content.

(4) The sampling and analysis is to be carried out using the sampling and analysis provided for in Divisions 2.2.3, 2.3.3 and 2.4.3 that apply to the combustion of solid, gaseous and liquid fuels.

4.96 Method 3—other metals

(1) Subject to this section, method 3 is the same as method 2 under section 4.95.

(2) If a fuel type (***i***) or carbonaceous input material delivered for the activity during the year accounts for more than 5% of total carbon input for the activity, based on a calculation using the factors specified in Schedule 3, sampling and analysis of fuel type (***i***) or carbonaceous input material must be carried out to determine its carbon content.

(3) The sampling and analysis is to be carried out using the methods set out in Divisions 2.2.4, 2.3.4 and 2.4.4 that apply to the combustion of solid, gaseous and liquid fuels.

Part 4.5—Industrial processes—emissions of hydrofluorocarbons and sulphur hexafluoride gases

4.97 Application

This Part applies to emissions of hydrofluorocarbons and sulphur hexafluoride gases.

4.98 Available method

(1) Subject to section 1.18, for estimating emissions of hydrofluorocarbons or sulphur hexafluoride during a year from the operation of a facility that is constituted by synthetic gas generating activities, one of the following methods must be used:
  (a) method 1 under section 4.102;
  (b) method 2, for both hydrofluorocarbons and sulphur hexafluoride, under section 4.103;
  (c) method 3:
    (i) for hydrofluorocarbons under subsection 4.104(1); and
    (ii) for sulphur hexafluoride under subsection 4.104(2).

(2) However, for incidental emissions another method may be used that is consistent with the principles in section 1.13.

Note: There is no method 4 for this Part.

4.99 Meaning of *hydrofluorocarbons*

Hydrofluorocarbons means any of the hydrofluorocarbons listed in the table in subsection 7A(2) of the Act.

4.100 Meaning of *synthetic gas generating activities*

Hydrofluorocarbons

(1) ***Synthetic gas generating activities***, for emissions of hydrofluorocarbons, are activities of a facility that:
  (a) require the use of any thing:
    (i) mentioned in paragraphs 4.16(1)(a) to (d) of the Regulations; and
    (ii) containing a refrigerant charge of more than 100 kilograms of refrigerants for each unit; and
    (iii) using a refrigerant that is a greenhouse gas with a Global Warming Potential of more than 1 000; and
  (b) are undertaken by a facility with a principal activity that is attributable to any one of the following ANZSIC industry classifications:
    (i) food product manufacturing (ANZSIC classification, Subdivision 11);

(ii) beverage and tobacco product manufacturing (ANZSIC classification, Subdivision 12);
(iii) retail trade (ANZSIC classification, Division G);
(iv) warehousing and storage services (ANZSIC classification, number 530);
(v) wholesale trade (ANZSIC classification Division F);
(vi) rental, hiring and real estate services (ANZSIC classification, Division L).

Note: A facility with a principal activity that is not attributable to any one of the ANZSIC industry classifications mentioned in subparagraph (b(i), (ii), (iii), (iv), (v) or (vi) is not required to report emissions of hydrofluorocarbons.

Sulphur hexafluoride

(2) ***Synthetic gas generating activities***, for emissions of sulphur hexafluoride, are any activities of a facility that:
(a) require the use of any equipment mentioned in paragraph 4.16(1)(d) of the Regulations; and
(b) emit sulphur hexafluoride.

4.101 Reporting threshold

For paragraph 4.22(1)(b) of the Regulations, the threshold mentioned in column 3 of an item in the following table resulting from a provision of this Determination mentioned in column 2 of that item is a reporting threshold.

Item	Provision in Determination	Threshold
1	Subparagraph 4.100(1)(a)(ii)	100 kilograms for each unit (hydrofluorocarbons)
2	Subsection 4.100(2)	Any emission (sulphur hexafluoride)

4.102 Method 1

(1) Method 1 is:

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

where:

$\boldsymbol{E_{jk}}$ is the emissions of gas type (***j***), either hydrofluorocarbons or sulphur hexafluoride, summed over each equipment type (***k***) during a year measured in CO_2-e tonnes.

$\boldsymbol{Stock_{jk}}$ is the stock of gas type (***j***), either hydrofluorocarbons or sulphur hexafluoride, contained in equipment type (***k***) during a year measured in CO_2-e tonnes.

$\boldsymbol{L_{jk}}$ is the default leakage rates for a year of gas type (***j***) mentioned in columns 3 or 4 of an item in the table in subsection (4) for the equipment type (***k***) mentioned in column 2 for that item.

(2) For the factor ***Stock***$_{jk}$, an estimation of the stock of synthetic gases contained in an equipment type must be based on one of 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.

(3) For equipment type (***k***), the equipment are the things mentioned in subregulation 4.16(1) of the Regulations.

(4) For subsection (1), columns 3 and 4 of an item in the following table set out default leakage rates of gas type (***j***), for either hydrofluorocarbons or sulphur hexafluoride, in relation to particular equipment types (***k***) mentioned in column 2 of the item:

Item	**Equipment type (k)**	**Default annual leakage rate of gas (j)**	
		Hydrofluorocarbons	**Sulphur hexafluoride**
1	Commercial air conditioning	0.09	
2	Commercial refrigeration	0.23	
3	Industrial refrigeration	0.16	
4	Gas insulated switchgear and circuit breaker applications		0.0089

4.103 Method 2

For paragraph 4.98(1)(b), method 2 for estimating emissions of hydrofluorocarbons or sulphur hexafluoride during a year uses the tables in Appendix A of the publication entitled *ENA Industry Guideline for* SF_6 *Management*, Energy Networks Association, 2008.

4.104 Method 3

(1) For paragraph 4.98(1)(c), method 3 for estimating emissions of hydrofluorocarbons uses the tables in Appendix B of the publication entitled *ENA Industry Guideline for* SF_6 *Management*, Energy Networks Association, 2008.

(2) For paragraph 4.98(1)(c), method 3 for estimating emissions of sulphur hexafluoride during a year uses the Tier 3 method set out in section 6.3 of the publication mentioned in subsection (1).

Chapter 5—Waste

Part 5.1—Preliminary

5.1 Outline of Chapter

This Chapter provides for emissions from the following sources:

(a) solid waste disposal on land (see Part 5.2);
(b) wastewater handling (domestic and commercial) (see Part 5.3);
(c) wastewater handling (industrial) (see Part 5.4);
(d) waste incineration (see Part 5.5).

Part 5.2—Solid waste disposal on land

Division 5.2.1—Preliminary

5.2 Application

(1) This Part applies to emissions released from:
  (a) the decomposition of organic material from:
    (i) solid waste disposal in a landfill; or
    (ii) the biological treatment of solid waste at a landfill or at a facility elsewhere; and
  (b) flaring of landfill gas.

(2) This Part does not apply to solid waste disposal in a landfill unless:
  (a) the landfill was open for the acceptance of waste on and after 1 July 2012; and
  (b) during a year, the landfill emits more than 10 000 tonnes of CO_2-e from solid waste disposal in the landfill.

(3) This Part does not apply to the biological treatment of solid waste at a facility (whether at a landfill or at a facility elsewhere) unless, during a year, the facility emits more than 10 000 tonnes of CO_2-e from the biological treatment of solid waste at the facility.

5.3 Available methods

(1) For the purposes of this Part, subject to section 1.18, for estimating emissions released from the operation of a facility (including a facility that is a landfill) during a year:
  (a) subject to paragraphs (c) and (d), one of the following methods must be used for emissions of methane from a landfill (other than from flaring of methane):
    (i) method 1 under section 5.4;
    (ii) method 2 under section 5.15;
    (iii) method 3 under section 5.18; and
  (b) one of the following methods must be used for emissions for each gas type released as a result of methane flared from the operation of a landfill:
    (i) method 1 under section 5.19;
    (ii) method 2 under section 5.20;
    (iii) method 3 under section 5.21; and
  (c) one of the following methods must be used for emissions from the biological treatment of solid waste at the facility by an enclosed composting activity:
    (i) method 1 under section 5.22;
    (ii) method 4 under section 5.22AA; and

(d) method 1 under section 5.22 must be used for emissions from the biological treatment of solid waste at the facility by a composting activity that is not an enclosed composting activity.

(2) Under paragraph (1)(b), the same method must be used for estimating emissions of each gas type.

(3) For incidental emissions another method may be used that is consistent with the principles in section 1.13.

Note: There is no method 4 for paragraphs (a) and (b). It is proposed that a method 4 will be developed in the future.

(4) If required, Division 5.2.7 is to be used to estimate legacy emissions.

Note: Division 5.2.7 will not be required unless the total amount of scope 1 emissions from the operation of the facility concerned during the year is more than 100 000 tonnes CO_2-e: see paragraphs (i) of item 1 and (j) of item 2 in the column headed “Matters to be identified” in the table in Part 6 of Schedule 3 to the *National Greenhouse and Energy Reporting Regulations 2008*.

Division 5.2.2—Method 1—emissions of methane released from landfills

5.4 Method 1—methane released from landfills (other than from flaring of methane)

(1) For subparagraph 5.3(1)(a)(i), method 1 is:

$$E_j = \left[CH_4^* - \gamma\,(Q_{cap} + Q_{flared} + Q_{tr})\right] \times (1-OF)$$

where:

$\boldsymbol{E_j}$ is the emissions of methane released by the landfill during the year measured in CO_2-e tonnes.

$\boldsymbol{CH_4^*}$ is the estimated quantity of methane in landfill gas generated by the landfill during the year as determined under subsection (2) or (3) and measured in CO_2-e tonnes.

γ is the factor $6.784 \times 10^{-4} \times 25$ converting cubic metres of methane at standard conditions to CO_2-e tonnes.

$\boldsymbol{Q_{cap}}$ is the quantity of methane in landfill gas captured for combustion from the landfill during the year and measured in cubic metres in accordance with Division 2.3.6.

$\boldsymbol{Q_{flared}}$ is the quantity of methane in landfill gas flared from the landfill during the year and measured in cubic metres in accordance with Division 2.3.6.

$\boldsymbol{Q_{tr}}$ is the quantity of methane in landfill gas transferred out of the landfill during the year and measured in cubic metres in accordance with Division 2.3.6.

OF is the oxidation factor (0.1) for near surface methane in the landfill.

(2) For subsection (1), if:

$$\frac{\gamma\,(Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

is less than or equal to 0.75, then:

$$CH_4^* = CH_{4gen}$$

where:

$\boldsymbol{CH_{4gen}}$ is the quantity of methane in landfill gas generation released from the landfill during the year estimated in accordance with subsection (5) and measured in CO_2-e tonnes.

(3) For subsection (1), if:

$$\frac{\gamma\,(Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

is greater than 0.75, then:

$$CH_4^{*} = \gamma\left(Q_{cap} + Q_{flared} + Q_{tr}\right) \times \left(\frac{1}{0.75}\right)$$

where:

γ is the factor 6.784 x 10^{-4} x 25 converting cubic metres of methane at standard conditions to CO_2-e tonnes.

Q_{cap} is the quantity of methane in landfill gas captured for combustion from the landfill during the year and measured in cubic metres.

(4) For subsections (1) and (3), Q_{cap} is to be calculated in accordance with Division 2.3.6.

(5) For subsection (2), CH_{4gen} must be calculated using the estimates mentioned in section 5.4A and the equations mentioned in sections 5.4B, 5.4C and 5.4D.

5.4A Estimates for calculating CH_{4gen}

For subsection 5.4(5), the estimates for calculating CH_{4gen} are the following:

(a) the tonnage of total solid waste disposed of in the landfill during the year estimated in accordance with section 5.5;
(b) the composition of the solid waste disposed of in the landfill during the year estimated in accordance with section 5.9;
(c) the degradable organic carbon content of the solid waste disposed of in the landfill by waste type estimated in accordance with section 5.12;
(d) the opening stock of degradable organic carbon in the solid waste at the landfill at the start of the first reporting period for the landfill estimated in accordance with section 5.13;
(e) methane generation constants (***k values***) for the solid waste at the landfill estimated in accordance with section 5.14;
(f) the fraction of degradable organic carbon dissimilated (***DOC_F***) estimated in accordance with section 5.14A;
(g) the methane correction factor for aerobic decomposition in the first year estimated in accordance with section 5.14B;
(h) the fraction by volume of methane generated in landfill gas estimated in accordance with section 5.14C;
(i) the number of months that have ended before methane generation at the landfill commences estimated in accordance with section 5.14D.

5.4B Equation—change in quantity of particular opening stock at landfill for calculating CH_{4gen}

(1) For subsection 5.4(5), this section applies if the result of the first equation in subsection 5.4(3)is, for the reporting year for which the result is calculated, (the ***current reporting year***), greater than 0.75.

(2) The change in the quantity of the opening stock of decomposable degradable organic carbon (ΔC_{OS_t}) that is:

(a) located in the landfill during the reporting year; and
(b) measured in tonnes; and
(c) lost through decomposition;

must be calculated using the equation mentioned in subsection (3).

(3) For subsection (2), the equation is:

$$\Delta C_{ost} = \frac{CH_4^*}{F \times 1.336 \times 25}$$

where:

t is the reporting year.

CH_4^* is the estimated quantity of methane in landfill gas generated by the landfill during the year, measured in CO_2-e tonnes.

F is the fraction of methane generated in landfill gas estimated in accordance with section 5.14C.

1.336 is the factor to convert a mass of carbon to a mass of methane.

25 is the factor to convert methane to carbon dioxide equivalent.

Note 1: For the definition of ***reporting year***, see the *National Greenhouse and Energy Reporting Regulations 2008*.

Note 2: If the result of the first equation in subsection 5.4(3):

(a) was, for a previous reporting year or years, greater than 0.75; and
(b) is, for the current reporting year, less than or equal to 0.75;

use:

(c) the calculation in section 5.4B to calculate the change in the opening stock of carbon for the final reporting year in which the result of that equation is greater than 0.75; and
(d) the calculation in section 5.4C to calculate the closing stock for that reporting year.

5.4C Equation—quantity of closing stock at landfill in particular reporting year

(1) For subsection 5.4(5), this section applies if the result of the first equation in subsection 5.4(3) is, for the reporting year for which the result is calculated, (the ***current reporting year***), greater than 0.75.

(2) The quantity of closing stock of decomposable degradable organic carbon (C_{cst}) in the most recent year to which subsection 5.4(3) applies:

(a) located in the landfill during the reporting year; and

(b) measured in tonnes;

must be calculated using the equation mentioned in subsection (3):

(3) For subsection (2), the equation is:

$$C_{cst} = C_{ost} - \Delta C_{ost}$$

where:

C_{cst} is the closing stock of carbon in the last year in which subsection 5.4(3) was used to calculate emissions.

C_{ost} is the opening stock of carbon in the first year in which 5.4(3) was used to calculate emissions.

ΔC_{ost} is the change in carbon stock for all years in which 5.4(3) applies and is estimated in accordance with 5.4B.

Note: The quantity of closing stock calculated in accordance with this section is the same as the quantity of opening stock for the current reporting year.

5.4D Equation—quantity of methane generated by landfill for calculating CH_{4gen}

For subsection 5.4(5), the quantity of methane generated by the landfill must be calculated using the following equation:

$$CH_{4gen} = \left(\Lambda C_{ost} + \Delta C_{at} \right) \times F \times 1.336 \times 25$$

where:

CH_{4gen} is the quantity of methane generated by the landfill as calculated under this section and measured in CO_2-e tonnes.

F is the fraction of methane generated in landfill gas estimated in accordance with section 5.14C.

1.336 is the factor to convert a mass of carbon to a mass of methane.

25 is the factor to convert methane to carbon dioxide equivalent.

ΔC_{ost} is the change in the quantity of the opening stock of decomposable degradable organic carbon derived from the sum of all waste mix types located in the landfill during the reporting year, measured in tonnes, lost through decomposition, and equals:

$$\Delta C_{ost} = \sum_i C_{osit} \times (1 - e^{-ki})$$

where:

$\boldsymbol{C_{osit}}$ is the quantity of decomposable degradable organic carbon accumulated in the landfill at the beginning of the reporting year from all waste mix types mentioned in subsection 5.11(1), measured in tonnes and equals:

$$\mathrm{C_{osit} = C_{csit\text{-}1}}$$

where:

$\boldsymbol{C_{csit\text{-}1}}$ is the closing stock of decomposable degradable organic carbon accumulated in the landfill in the year immediately preceding the reporting year from all waste mix types mentioned in subsection 5.11(1), measured in tonnes and equals:

$$\mathrm{C_{csit} = C_{osit} - \Delta C_{osit} + C_{ait} - \Delta C_{ait}}$$

and:

$\Delta\boldsymbol{C_{at}}$ is the change in the quantity of decomposable degradable organic carbon derived from the sum of all waste mix types deposited at the landfill during the reporting year, measured in tonnes, lost through decomposition, and equals:

$$\Delta \mathrm{C_{at}} = \textstyle\sum_i \mathrm{C_{ait}} \times [1 - e^{-ki \times (13 - M)/12}]$$

where:

$\boldsymbol{C_{ait}}$ is the quantity of degradable organic carbon in all waste mix types mentioned in subsection 5.11(1) deposited at the landfill during the reporting year , measured in tonnes and is equal to:

$$\mathrm{C_{ait} = (Q_{it} \times DOC_i \times DOC_{fi} \times MCF)}$$

where:

$\boldsymbol{Q_{it}}$ is the quantity of all waste mix types mentioned in subsection 5.11(1) deposited at the landfill during the reporting year, measured in tonnes.

$\boldsymbol{DOC_i}$ is the fraction of the degradable organic carbon content of the solid waste for all waste mix types mentioned in subsection 5.11(1) and deposited at the landfill.

$\boldsymbol{DOC_{fi}}$ is the fraction of decomposable degradable organic carbon for all waste mix types mentioned in subsection 5.11(1).

MCF is the methane correction factor for aerobic decomposition for the facility during the reporting year.

and where:

$\boldsymbol{k_i}$ is the methane generation constant for all waste mix types mentioned in subsection 5.11(1).

t is the reporting year.

M is the number of months before commencement of methane generation at the landfill plus 7.

$\boldsymbol{\Sigma_i}$ is the sum for all waste mix types mentioned in subsection 5.11(1).

Note 1: For the definition of ***reporting year***, see the *National Greenhouse and Energy Reporting Regulations 2008*.

Note 2: For the source of the equation included in:

(a) section 5.4D, see Volume 5, Chapter 3 of the 2006 IPCC Guidelines, equation 3.6; and

(b) the definition of ΔC_{ost}, see Volume 5, Chapter 3 of the 2006 IPCC Guidelines, equation 3.5; and

(c) the definition of ΔC_{at}, see Volume 5, Chapter 3 of the 2006 IPCC Guidelines, equation 3.A1.13; and

(d) the definition of ΔC_{ait}, see Volume 5, Chapter 3 of the 2006 IPCC Guidelines, equation 3.2.

Note 3: For each reporting year to which subsection 5.4(3) applies, use the equation mentioned in section 5.4B

Note 4: If the result of the first equation in subsection 5.4(3):

(a) was, for a previous reporting year or years, greater than 0.75; and

(b) is, for the reporting year for which the result is calculated, (the ***current reporting year***), less than or equal to 0.75;

use:

(c) the calculation in section 5.4B to calculate the change in the opening stock of carbon for the final reporting year in which the result of that equation is greater than 0.75; and

(d) the calculation in section 5.4C to calculate the closing stock for that reporting year.

5.5 Criteria for estimating tonnage of total solid waste

For the purpose of estimating the tonnage of waste disposed of in a landfill, the tonnage of total solid waste received at the landfill during the year is to be estimated using one of the following criteria:

(a) as provided in section 5.6 (***criterion A***);

(b) as provided in section 5.7 (***criterion AAA***);

(c) as provided in section 5.8 (***criterion BBB***).

5.6 Criterion A

For paragraph 5.5(a), criterion A is:

(a) the amount of solid waste received at the landfill during the year as evidenced by invoices; or

(b) if the amount of solid waste received at the landfill during the year is measured in accordance with State or Territory legislation applying to the landfill—that measurement.

5.7 Criterion AAA

For paragraph 5.5(b), criterion AAA is the direct measurement of quantities of solid waste received at the landfill during the year using measuring equipment calibrated to a measurement requirement.

5.8 Criterion BBB

For paragraph 5.5(c), criterion BBB is the estimation of solid waste received at the landfill during the year in accordance with industry estimation practices (such as the use of accepted industry weighbridges, receipts, invoices, other documents or records or population and per-capita waste generation rates).

5.9 Composition of solid waste

(1) For paragraph 5.4A(b), the composition of solid waste received at the landfill during the year must be classified by:
   (a) the general waste streams mentioned in subsection 5.10(1); and
   (b) the homogenous waste streams mentioned in subsection 5.10A(1).

(2) For solid waste received at the landfill during a year, an estimate of tonnage of:
   (a) each general waste stream must be provided in accordance with section 5.10; and
   (b) each homogenous waste stream must be provided in accordance with section 5.10A.

(3) For the following general and homogenous waste streams there must be a further classification in accordance with section 5.11 showing the waste mix types in each waste stream (expressed as a percentage of the total tonnage of solid waste in the waste stream):
   (a) municipal solid waste class I;
   (ab) municipal solid waste class II;
   (b) commercial and industrial waste;
   (c) construction and demolition waste;
   (d) shredder flock.

5.10 General waste streams

(1) For paragraph 5.9(1)(a), the general waste streams are as follows:
   (a) municipal solid waste class I;
   (ab) municipal solid waste class II;
   (b) commercial and industrial waste;
   (c) construction and demolition waste.

(2) Subject to subsection (3), for paragraph 5.9(2)(a), the tonnage of each waste stream mentioned in subsection (1) must be estimated:
   (a) if the operator of the landfill is required, under a law of the State or Territory in which the landfill is located, to collect data on tonnage of waste received at the landfill according to the waste streams mentioned in subsection (1)—by using that data; or

(b) if paragraph (a) does not apply and the operator of the landfill is able to estimate, in accordance with one of the criteria set out in section 5.5, the tonnage of the waste streams mentioned in subsection (1)—by using that criterion; or

(c) if paragraphs (a) and (b) do not apply and there is no restriction on the waste streams that can be received at the landfill—by:

  (i) for estimating the tonnage of the municipal solid waste class I stream if the landfill did not receive municipal solid waste class II—using the percentage value specified in columns 2 to 9 of item 1 of the following table for the State or Territory in which the landfill is located; and

  (ii) for estimating the tonnage of the municipal solid waste class II stream if the landfill did not receive municipal solid waste class I—using the percentage value specified in columns 2 to 9 of item 1 of the following table for the State or Territory in which the landfill is located; and

  (iii) for estimating the tonnage of the municipal solid waste class I stream and the municipal solid waste class II stream if the landfill received both municipal solid waste classes—halving the percentage value specified in columns 2 to 9 of item 1 of the following table for the State or Territory in which the landfill is located and using that value for each of the municipal solid waste streams; and

  (iv) for estimating the tonnage of the commercial and industrial waste stream—using the percentage value specified in columns 2 to 9 of item 2 of the following table for the State or Territory in which the landfill is located; and

  (v) for estimating the tonnage of the construction and demolition waste stream—using the percentage value specified in columns 2 to 9 of item 3 of the following table for the State or Territory in which the landfill is located.

Waste streams and estimation of tonnage

Item	**Col. 1** **Waste stream**	**Col. 2** **NSW** **%**	**Col. 3** **VIC** **%**	**Col. 4** **QLD** **%**	**Col. 5** **WA** **%**	**Col. 6** **SA** **%**	**Col. 7** **TAS** **%**	**Col. 8** **ACT** **%**	**Col. 9** **NT** **%**
1	Municipal solid waste	31	36	43	26	36	57	43	43
2	Commercial and industrial	42	24	14	17	19	33	42	14
3	Construction and demolition	27	40	43	57	45	10	15	43

(3) For paragraph 5.9(2)(a), if the landfill is permitted to receive only:

(a) non-putrescible waste; or

(b) commercial and industrial waste and construction and demolition waste;

the waste may be assumed to consist of only commercial and industrial waste and construction and demolition waste.

(4) If subsection (3) applies, the tonnage of each waste stream mentioned in column 1 of the following table must be estimated:

(a) if the operator of the landfill is required, under a law of the State or Territory in which the landfill is located, to collect data on tonnage of waste received at the landfill according to the waste streams set out in column 1—by using that data; or

(b) if paragraph (a) does not apply and the operator of the landfill is able to estimate, in accordance with one of the criteria set out in section 5.5, the tonnage of the waste streams set out in column 1—by using that data; or

(c) if paragraphs (a) and (b) do not apply—by using the percentage values in columns 2 to 9 for the State or Territory in which the landfill is located for each waste stream in column 1.

Waste streams and estimation of tonnage

Item	Col. 1 Waste stream	Col. 2 NSW %	Col. 3 VIC %	Col. 4 QLD %	Col. 5 WA %	Col. 6 SA %	Col. 7 TAS %	Col. 8 ACT %	Col. 9 NT %
1	Commercial and industrial waste	61	38	25	23	30	77	74	25
2	Construction and demolition waste	39	62	75	77	70	23	26	75

(5) If subsection (3) applies and the landfill is permitted to receive only one of the waste streams set out in column 1 of the table in subsection (4), that waste stream will be taken to constitute the total waste received.

5.10A Homogenous waste streams

(1) For paragraph 5.9(1)(b), the homogenous waste streams have the characteristics mentioned in subsection (2) and are as follows:

(a) alternative waste treatment residues;

(b) shredder flock;

(c) inert waste.

(2) Homogenous waste streams have the following characteristics:

(a) they are from a single known and verifiable origin, as evidenced by invoices or, if delivery does not involve a commercial transaction, other delivery documentation;

(b) they are not extracted from a general waste stream;

(c) they do not undergo compositional change between generation and delivery to a landfill;

(d) they are delivered in loads containing only the waste mentioned in paragraph (1)(a), (b) or (c).

(3) For paragraph 5.9(2)(b), the tonnage of each homogenous waste stream mentioned in subsection (1) must be estimated:
- (a) by using the amount of homogenous waste received at the landfill during the year as evidenced by invoices; or
- (b) if the amount of homogenous waste received at the landfill during the year is measured in accordance with State or Territory legislation applying to the landfill—by using that measurement; or
- (c) by using direct measurement of quantities of homogenous waste received at the landfill during the year using measuring equipment calibrated to a measurement requirement; or
- (d) in accordance with industry estimation practices (such as the use of accepted industry weighbridges, receipts, invoices, other documents or records or population and per-capita waste generation rates).

5.11 Waste mix types

(1) For subsection 5.9(3), the waste mix types are as follows:
- (a) food;
- (b) paper and cardboard;
- (c) textiles;
- (d) garden and park;
- (e) wood and wood waste;
- (f) sludge;
- (g) nappies;
- (h) rubber and leather;
- (i) inert waste.

(2) The percentage of the total waste tonnage for each waste mix type mentioned in column 1 of an item in the following table must be estimated by using:
- (a) sampling techniques specified in:
  - (i) waste audit guidelines issued by the State or Territory in which the landfill is located; or
  - (ii) if no guidelines have been issued by the State or Territory in which the landfill is located—ASTM D 5231–92 (Reapproved 2008) or an equivalent Australian or international standard; or
- (b) the tonnage of each waste mix type received at the landfill estimated in accordance with the criteria set out in section 5.5; or
- (c) subject to subsection 5.11(3), the default waste stream percentages in columns 2, 3, 4 and 5 for the item for each waste mix type.

Default waste stream percentage for waste mix type

Item	Column 1 Waste mix type	Column 2 Municipal solid waste class I default (%)	Column 3 Municipal solid waste class II default (%)	Column 4 Commercial and industrial waste default (%)	Column 5 Construction and demolition waste default (%)
1	Food	35	40.3	21.5	0
2	Paper and cardboard	13	15.0	15.5	3
3	Garden and park	16.5	3.9	4	2
4	Wood and wood waste	1	1.2	12.5	6
5	Textiles	1.5	1.7	4	0
6	Sludge	0	0	1.5	0
7	Nappies	4	4.6	0	0
8	Rubber and leather	1	1.2	3.5	0
9	Inert waste	28	32.1	37.5	89

(3) If the licence or other authorisation authorising the operation of the landfill restricts the waste mix types (***restricted waste mix type***) that may be received at the landfill, the percentage of the total waste volume for each waste mix type mentioned in column 1 of an item of the following table (appearing immediately before the example) must be estimated:

(a) for a restricted waste mix type—by using the maximum permitted tonnage of the restricted waste mix type received at the landfill, as a percentage of the total waste received at the landfill; and

(b) for each waste mix type that is not a restricted waste mix type (***unrestricted waste mix type***)—by adjusting the default percentages in columns 2, 3, 4 and 5 of the following table for the item for each unrestricted waste mix type, in accordance with the following formula:

$$W_{mtuadj} = W_{mtu} + \frac{\left(W_{mtr} - W_{mtrmax}\right) \times W_{mtu}}{\sum W_{mtu}}$$

where:

W_{mtuadj} is the adjusted percentage for each unrestricted waste mix type.

W_{mtu} is the default percentage for each unrestricted waste mix type in columns 2, 3, 4 and 5 of the table appearing immediately before the example.

W_{mtr} is the default percentage for each restricted waste mix type in columns 2, 3, 4 and 5 of the table appearing immediately before the example.

W_{mtrmax} is the maximum percentage for each restricted waste mix type.

∑ means sum the results for each unrestricted waste mix type.

Default waste stream percentage for waste mix type

Item	Column 1 Waste mix type	Column 2 Municipal solid waste class I default (%)	Column 3 Municipal solid waste class II default (%)	Column 4 Commercial and industrial waste default (%)	Column 5 Construction and demolition waste default (%)
1	Food	35	40.3	21.5	0
2	Paper and cardboard	13	15.0	15.5	3
3	Garden and park	16.5	3.9	4	2
4	Wood and wood waste	1	1.2	12.5	6
5	Textiles	1.5	1.7	4	0
6	Sludge	0	0	1.5	0
7	Nappies	4	4.6	0	0
8	Rubber and leather	1	1.2	3.5	0
9	Inert waste	28	32.1	37.5	89

Example:

A landfill in a State is licensed only to receive commercial and industrial waste. A condition of the licence is that the landfill is restricted to receiving no more than 5% (W_{mtrmax} = 5%) food waste in its deliveries. The landfill operator accounts for this restriction by using the formula for each unrestricted waste type (W_{mtu}) in the table above. So, for paper and paper board waste, the calculation is:

$$W_{mtuadj} = 15.5 + \frac{(21.5 - 5) \times 15.5}{(15.5 + 4 + 12.5 + 4 + 1.5 + 3.5 + 37.5)}$$

$$= 18.8$$

The operator would continue to use the formula for each unrestricted waste mix type. For the restricted waste mix type the percentage used is W_{mtrmax}.

The following table sets out all the relevant variables and results for this example.

Item	Waste mix type	W_{mtu} (%)	W_{mtr} (%)	W_{mtrmax} (%)	Wmt_{adj} (%)
1	Food		21.5	5.0	
2	Paper and cardboard	15.5			18.8
3	Garden and park	4.0			4.8
4	Wood and wood waste	12.5			15.1
5	Textiles	4.0			4.8

Item	**Waste mix type**	**W_{mtu} (%)**	**W_{mtr} (%)**	**W_{mtrmax} (%)**	**Wmt_{adj} (%)**
6	Sludge	1.5			1.8
7	Nappies	0.0			0.0
8	Rubber and leather	3.5			4.2
9	Inert waste	37.5			45.4

5.11A Certain waste to be deducted from waste received at landfill when estimating waste disposed in landfill

(1) When estimating the tonnage of waste by waste mix type disposed of in a landfill, the tonnage of the following waste is to be deducted from the estimates of waste received at the landfill:

(a) waste that is taken from the landfill for recycling or biological treatment;

(b) waste that is received at the landfill for recycling or biological treatment at the landfill site;

(c) waste that is used at the landfill for construction purposes, daily cover purposes, intermediate cover purposes or final capping and cover purposes.

(2) If the waste to be deducted under subsection (1) is a general waste stream mentioned in subsection 5.10(1), the tonnage of the waste to be deducted may be estimated by using the default waste stream percentages mentioned in subsection 5.11(2) for each waste mix type.

5.12 Degradable organic carbon content

For paragraph 5.4A(c), the amount of the degradable organic carbon content of the solid waste at the landfill must be estimated by using the degradable organic carbon values in column 3 of an item in the following table for each waste mix type in column 2 for that item.

Item	**Waste mix type**	**Degradable organic carbon value**
1	Food	0.15
2	Paper and cardboard	0.40
3	Garden and green	0.20
4	Wood	0.43
5	Textiles	0.24
6	Sludge	0.05
7	Nappies	0.24
8	Rubber and Leather	0.39
9	Inert waste	0.00
10	Alternative waste treatment residues	0.08

5.13 Opening stock of degradable organic carbon for the first reporting period

(1) For paragraph 5.4A(d), the amount of opening stock of degradable organic carbon at the landfill at the start of the first reporting period for the landfill must be estimated in accordance with subsection 5.4(5):

- (a) by using the details of the total tonnage of solid waste (broken down into waste stream and waste mix type and estimated in accordance with section 5.5) disposed of in the landfill each year over the lifetime of the landfill until the start of the first reporting period for the landfill; or
- (b) if the operator of a landfill is unable to comply with paragraph (a)—by using the following information in relation to the landfill:
  - (i) the number of years that the landfill has been in operation;
  - (ii) the estimated annual tonnage of solid waste disposed of in the landfill over the lifetime of the landfill until the start of the first reporting period for the landfill, worked out in accordance with subsection (2);
  - (iii) the State or Territory in which the landfill is located.

(2) For subparagraph (1)(b)(ii), the estimated annual tonnage of waste is to be worked out:

- (a) by using the average annual tonnage of solid waste disposed of in the landfill for the years for which data is available; or
- (b) by conducting a volumetric survey of the landfill in accordance with subsections (3) and (4); or
- (c) by using industry estimation practices (such as the use of accepted industry weighbridges, receipts, invoices, other documents or records or population and per-capita waste generation rates).

(3) For paragraph (2)(b), the survey:

- (a) must be a ground-based survey or an aerial survey; and
- (b) must be conducted by a qualified surveyor.

(4) For the volumetric survey, the volume of waste is to be converted to mass by using one of the following volume-to-mass conversion factors:

- (a) the landfill volume-to-mass conversion factors that were used during the most recent reporting year in order to comply with a landfill reporting requirement of the State or Territory in which the landfill is located;
- (b) if the factors mentioned in paragraph (a) were not used during the most recent reporting year in order to comply with a landfill reporting requirement of the State or Territory in which the landfill is located—the volume-to-mass conversion factors specified in column 3 of an item in the following table for a waste stream specified in column 2 of the item.

Item	Waste stream	Volume-to-mass conversion factor
1	Municipal solid waste	1.1 tonnes per cubic metre
2	Commercial and industrial waste	1.1 tonnes per cubic metre
3	Construction and demolition waste	1.1 tonnes per cubic metre

5.14 Methane generation constants—(k values)

(1) This section is made for paragraph 5.4A(e).

(2) Before selecting methane generation constants (***k values***) from the table in subsection (6), the landfill operator must:

(a) obtain records of each of the following for the 10 year period ending immediately prior to the reporting year for which the landfill operator selects k values:

(i) mean annual evaporation;

(ii) mean annual precipitation;

(iii) mean annual temperature; and

(b) based on those records, identify, for the landfill facility, the landfill classification mentioned in column 2 of the table.

Note: See subsection (6) for definitions related to the requirements in paragraphs (2)(a) and (b).

(3) A landfill operator must select k values from either:

(a) the table in subsection (5); or

(b) the table in subsection (6).

(4) If a landfill operator selects k values from the table in subsection (6) in a reporting year, the landfill operator must select k values from that table in each subsequent reporting year.

(5) The k values for solid waste at a landfill in a State or Territory mentioned in column 2 of an item in the following table are the constants set out in column 4 for a waste mix type mentioned in column 3 for the item.

k values for Solid Waste at a Landfill

Item	State or Territory	Waste mix type	k values
1	NSW	Food	0.185
		Paper and cardboard	0.06
		Garden and Green	0.10
		Wood	0.03
		Textiles	0.06
		Sludge	0.185
		Nappies	0.06
		Rubber and Leather	0.06
		Alternative waste treatment residue	0.06
2	VIC, WA, SA, TAS, ACT	Food	0.06
		Paper and cardboard	0.04
		Garden and Green	0.05
		Wood	0.02
		Textiles	0.04

k values for Solid Waste at a Landfill

Item	State or Territory	Waste mix type	k values
		Sludge	0.06
		Nappies	0.04
		Rubber and Leather	0.04
		Alternative waste treatment residue	0.04
3	QLD, NT	Food	0.4
		Paper and cardboard	0.07
		Garden and Green	0.17
		Wood	0.035
		Textiles	0.07
		Sludge	0.4
		Nappies	0.07
		Rubber and Leather	0.07
		Alternative waste treatment residue	0.07

(6) The k values for solid waste at a landfill with a landfill classification mentioned in column 2 of an item in the following table are the constants set out in column 4 for a waste mix type mentioned in column 3 for the item.

k values for Solid Waste at a Landfill

Item	Landfill classification	Waste mix type	k values
1	Temperate dry	Food	0.06
		Paper and cardboard	0.04
		Garden and Green	0.05
		Wood	0.02
		Textiles	0.04
		Sludge	0.06
		Nappies	0.04
		Rubber and Leather	0.04
		Alternative waste treatment residue	0.04
2	Temperate wet	Food	0.185
		Paper and cardboard	0.06
		Garden and Green	0.10
		Wood	0.03
		Textiles	0.06
		Sludge	0.185
		Nappies	0.06
		Rubber and Leather	0.06
		Alternative waste treatment residue	0.06
3	Tropical dry	Food	0.085

k values for Solid Waste at a Landfill

Item	Landfill classification	Waste mix type	k values
		Paper and cardboard	0.045
		Garden and Green	0.065
		Wood	0.025
		Textiles	0.045
		Sludge	0.085
		Nappies	0.045
		Rubber and Leather	0.045
		Alternative waste treatment residue	0.045
4	Tropical wet	Food	0.4
		Paper and cardboard	0.07
		Garden and Green	0.17
		Wood	0.035
		Textiles	0.07
		Sludge	0.4
		Nappies	0.07
		Rubber and Leather	0.07
		Alternative waste treatment residue	0.07

(7) In this section:

Bureau of Meteorology Guideline means the document titled *Guidelines for the Siting and Exposure of Meteorological Instruments and Observing Facilities* (Observation Specification No. 2013.1), published by the Bureau of Meteorology in January 1997.

Note: The Bureau of Meteorology Guideline is available at www.bom.gov.au.

mean annual evaporation means the mean annual evaporation:

(a) recorded at the landfill by a meteorological station that is established and maintained in accordance with the Bureau of Meteorology Guideline; or

(b) if paragraph (a) does not apply—recorded by a Bureau of Meteorology weather station that:

  (i) is located nearest to the landfill; and

  (ii) records mean annual evaporation.

mean annual precipitation means the mean annual precipitation:

(a) recorded at the landfill by a meteorological station that is established and maintained in accordance with the Bureau of Meteorology Guideline; or

(b) if paragraph (a) does not apply—recorded by a Bureau of Meteorology weather station that:

  (i) is located nearest to the landfill; and

  (ii) records mean annual precipitation.

mean annual temperature means the mean annual temperature:

(a) recorded at the landfill by a meteorological station that is established and maintained in accordance with the Bureau of Meteorology Guideline; or

(b) if paragraph (a) does not apply—recorded by a Bureau of Meteorology weather station that:

  (i) is located nearest to the landfill; and

  (ii) records mean annual temperature.

Note: The Bureau of Meteorology weather station directory is available at www.bom.gov.au.

temperate dry, for a landfill, means that the landfill has:

(a) a mean annual temperature that is 20° centigrade or less; and

(b) a ratio of mean annual precipitation to mean annual evaporation that is less than 1.

temperate wet, for a landfill, means that the landfill has:

(a) a mean annual temperature that is 20° centigrade or less; and

(b) a ratio of mean annual precipitation to mean annual evaporation that is greater than 1.

tropical dry, for a landfill, means that the landfill has:

(a) a mean annual temperature that is greater than 20° centigrade; and

(b) a mean annual precipitation that is less than 1 000 mm.

tropical wet, for a landfill, means that the landfill has:

(a) a mean annual temperature that is greater than 20° centigrade; and

(b) a mean annual precipitation that is 1 000 mm or more.

5.14A Fraction of degradable organic carbon dissimilated (DOC_F)

For paragraph 5.4A(f), the fraction of organic carbon dissimilated (DOC_F) for a waste mix type mentioned in column 2 of an item of following the table is the value mentioned in column 3 for the item.

Item	Waste mix type	DOC_F value
1	Food	0.84
2	Paper and cardboard	0.49
3	Garden and green	0.47
4	Wood	0.23
5	Textiles	0.50
6	Sludge	0.50
7	Nappies	0.50
8	Rubber and leather	0.50
9	Inert waste	0.00
10	Alternative waste treatment residues	0.50

5.14B Methane correction factor (MCF) for aerobic decomposition

For paragraph 5.4A(g), the methane correction factor for aerobic decomposition is 1.

5.14C Fraction by volume generated in landfill gas that is methane (F)

For paragraph 5.4A(h), the fraction by volume of methane generated in landfill gas is 0.5.

5.14D Number of months before methane generation at landfill commences

For paragraph 5.4A(i), the number of months that have ended before methane generation at the landfill commences is 6.

Note: To calculate the value of ***M***, add 7 to the number of months mentioned in section 5.14D. Using the number of months mentioned in section 5.14D, the calculation would be 6 plus 7 and the value of ***M*** would be 13.

Division 5.2.3—Method 2—emissions of methane released from landfills

Subdivision 5.2.3.1—methane released from landfills

5.15 Method 2—methane released by landfill (other than from flaring of methane)

(1) For subparagraph 5.3(1)(a)(ii), method 2 is that the following calculations must be performed:

(a) calculate the amount of methane emissions released by the landfill during the reporting year, measured in CO_2-e tonnes, using the following equation:

$$\boldsymbol{E_j} = \sum\nolimits_z \boldsymbol{E_{jz}}\text{; and}$$

(b) calculate the amount of emissions of methane released by the landfill from a sub-facility zone during the reporting year, measured in CO_2-e tonnes, using the following equation:

$$\boldsymbol{E_{jz}} = [CH_{4genz} - \gamma(Q_{capz} + Q_{flaredz} + Q_{trz})] \times (1 - OF)$$

where:

$\boldsymbol{E_j}$ is the emissions of methane released by the landfill during the reporting year, measured in CO_2-e tonnes.

$\boldsymbol{E_{jz}}$ is the emissions of methane released by the landfill from a sub-facility zone during the reporting year, measured in CO_2-e tonnes.

$\boldsymbol{CH_{4genz}}$ is the estimated quantity of methane in landfill gas generated by the landfill from a sub-facility zone during the reporting year, worked out in accordance with subsection (2), measured in CO_2-e tonnes.

$\boldsymbol{\gamma}$ is the factor $6.784 \times 10^{-4} \times 25$ converting cubic metres of methane at standard conditions measured to CO_2-e tonnes.

$\boldsymbol{Q_{capz}}$ is the quantity of methane in landfill gas captured for combustion by the landfill from a sub-facility zone during the reporting year, measured in cubic metres in accordance with Division 2.3.6.

$\boldsymbol{Q_{flaredz}}$ is the quantity of methane in landfill gas flared by the landfill from a sub-facility zone during the reporting year, measured in cubic metres in accordance with Division 2.3.6.

$\boldsymbol{Q_{trz}}$ is the quantity of methane in landfill gas transferred out of the landfill from a sub-facility zone during the reporting year, measured in cubic metres in accordance with Division 2.3.6.

$\boldsymbol{OF}$ is the oxidation factor (0.1) for near surface methane in the landfill.

$\sum_z$ is sum for all sub-facility zones.

(2) For paragraph (1)(b), $\boldsymbol{CH_{4genz}}$ for each sub-facility zone must be worked out:

  (a) using the estimates mentioned in section 5.4A and the equations mentioned in sections 5.4B, 5.4C and 5.4D; and

  (b) for each waste mix type mentioned in column 3 of the table in subsection 5.14(6)—using the method for working out the methane generation constant and the formula for calculating the adjusted methane generation constant mentioned in section 5.17L.

(3) For subsection (1), for a landfill, if:

$$\frac{\gamma\ (Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

is less than or equal to the collection efficiency amount for the landfill calculated in accordance with section 5.15C, then:

$$CH_4^* = CH_{4gen}$$

where:

$\boldsymbol{Q_{cap}}$ is the quantity of methane in landfill gas captured for combustion from the landfill during the year, measured in cubic metres in accordance with Division 2.3.6.

$\boldsymbol{Q_{flared}}$ is the quantity of methane in landfill gas flared from the landfill during the year, measured in cubic metres in accordance with Division 2.3.6.

$\boldsymbol{Q_{tr}}$ is the quantity of methane in landfill gas transferred out of the landfill during the year, measured in cubic metres in accordance with Division 2.3.6.

$\boldsymbol{CH_4^*}$ is the estimated quantity of methane in landfill gas generated by the landfill during the year, measured in CO_2-e tonnes.

$\boldsymbol{CH_{4gen}}$ is the quantity of methane in landfill gas generation released from the landfill during the year estimated in accordance with subsection 5.4(5) and measured in CO_2-e tonnes.

(4) For subsection (1), if:

$$\frac{\gamma\left(Q_{cap} + Q_{flared} + Q_{tr}\right)}{CH_{4gen}}$$

is more than the collection efficiency amount for the landfill calculated in accordance with section 5.15C, then:

$$CH_{4\ z}^{*} = \gamma\left(Q_{capz} + Q_{flaredz} + Q_{trz}\right) \times \left(\frac{1}{CEA}\right)$$

where:

γ is the factor 6.784 × 10^{-4} × 25 converting cubic metres of methane at standard conditions measured to CO_2-e tonnes.

CEA is the collection efficiency amount for the landfill calculated in accordance with section 5.15C.

$CH_{4\ z}^{*}$ is the estimated quantity of methane in landfill gas generated by the sub-facility zone during the year, measured in CO_2-e tonnes.

CH_{4gen} is the quantity of methane in landfill gas generation released from the landfill during the year, estimated in accordance with subsection 5.4(5) and measured in CO2-e tonnes.

Q_{cap} is the quantity of methane in landfill gas captured for combustion from the landfill during the year, measured in cubic metres in accordance with Division 2.3.6.

Q_{capz} is the quantity of methane in landfill gas captured for combustion by the landfill from a sub-facility zone during the reporting year, measured in cubic metres in accordance with Division 2.3.6.

Q_{flared} is the quantity of methane in landfill gas flared from the landfill during the year, measured in cubic metres in accordance with Division 2.3.6.

$Q_{flaredz}$ is the quantity of methane in landfill gas flared by the landfill from a sub-facility zone during the reporting year, measured in cubic metres in accordance with Division 2.3.6.

Q_{tr} is the quantity of methane in landfill gas transferred out of the landfill during the year, measured in cubic metres in accordance with Division 2.3.6.

Q_{trz} is the quantity of methane in landfill gas transferred out of the landfill from a sub-facility zone during the reporting year, measured in cubic metres in accordance with Division 2.3.6.

(5) For subsection (1), if the result of the first equation in subsection (4) is, for the reporting year for which the result is calculated (the ***current reporting year***), greater than the collection efficiency amount for the landfill calculated in accordance with section 5.15C:

 (a) the change in the quantity of the opening stock of decomposable degradable organic carbon (ΔC_{ost}) must be calculated using the equation mentioned in section 5.15A; and
 (b) the quantity of the closing stock of decomposable degradable organic carbon (ΔC_{cst}) must be calculated using the equation mentioned in section 5.15B.

(6) This method may be used only if specific information is available on the waste mix types at the landfill.

Note 1: For the definition of ***reporting year***, see the *National Greenhouse and Energy Reporting Regulations 2008*.

Note 2: For provisions regarding the selection and requirements of representative zones, see sections 5.16 to 5.17I.

Note 3: Section 5.17AA sets out, for a landfill operator using method 2 in Division 5.2.3 or method 3 in Division 5.2.4, the number of sub-facility zones that the landfill operator may select and the requirements for sub-facility zones that the landfill operator must comply with.

5.15A Equation—change in quantity of particular opening stock at landfill for calculating CH_{4gen}

(1) For paragraph 5.15(5)(a), this section applies if the result of the first equation in subsection 5.15(4) is, for the reporting year for which the result is calculated (the ***current reporting year***), greater than the collection efficiency amount for the landfill calculated in accordance with section 5.15C.

(2) The change in the quantity of the opening stock of decomposable degradable organic carbon (ΔC_{OS_t}) that is:

(a) located in the landfill during the reporting year; and

(b) measured in tonnes; and

(c) lost through decomposition;

must be calculated using the equation mentioned in subsection (3).

(3) For subsection (2), the equation is:

$$\Delta C_{ost} = \frac{CH_4^*}{F \times 1.336 \times 25}$$

where:

t is the reporting year.

F is the fraction of methane generated in landfill gas estimated in accordance with section 5.14C.

Note 1: For the definition of ***reporting year***, see the *National Greenhouse and Energy Reporting Regulations 2008*.

Note 2: If the result of the first equation in subsection 5.15(4):

(a) was, for a previous reporting year or years, greater than the collection efficiency amount for the landfill calculated in accordance with section 5.15C; and

(b) is, for the current reporting year, less than or equal to the collection efficiency amount for the landfill calculated in accordance with section 5.15C;

use:

(c) the calculation in section 5.15A to calculate the change in the opening stock of carbon for the final reporting year in which the result of that equation is greater than the collection efficiency amount for the landfill calculated in accordance with section 5.15C; and

(d) the calculation in section 5.15B to calculate the closing stock for that reporting year.

5.15B Equation—quantity of closing stock at landfill in particular reporting year

(1) For paragraph 5.15(5)(b), this section applies if the result of the first equation in subsection 5.15(4) is, for the reporting year for which the result is calculated (the ***current reporting year***), greater than the collection efficiency amount for the landfill calculated in accordance with section 5.15C.

(2) The quantity of closing stock of decomposable degradable organic carbon (C_{cst}) in the most recent year to which subsection 5.15(4) applies:

- (a) located in the landfill during the reporting year; and
- (b) measured in tonnes;

must be calculated using the equation mentioned in subsection (3).

(3) For subsection (2), the equation is:

$$C_{cst} = C_{ost} - \Delta C_{ost}$$

where:

C_{cst} is the closing stock of carbon in the last year in which subsection 5.15(4) was used to calculate emissions.

C_{ost} is the opening stock of carbon in the first year in which 5.15(4) was used to calculate emissions.

ΔC_{ost} is the change in carbon stock for all years in which 5.15(4) applies and is estimated in accordance with 5.15A

Note: The quantity of closing stock calculated in accordance with this section is the same as the quantity of opening stock for the current reporting year.

5.15C Equation—collection efficiency limit at landfill in particular reporting year

(1) Subject to subsection (2), the collection efficiency limit for a landfill is calculated using the following formula:

$$\frac{\left(A3 \times 60\% + A4 \times 75\% + A5 \times 95\%\right)}{\left(A2 + A3 + A4 + A5\right)}$$

where:

A2 is the area of the landfill in square metres, regardless of cover type, without active gas collection.

A3 is the area of the landfill in square metres that has daily soil cover and active gas collection.

A4 is the area of the landfill in square metres that has active gas collection and:

- (a) a top cover that is an intermediate type; or
- (b) a final cover of clay that is less than 1 metre thick; or

(c) a phytocap layer that is at least 1 metre thick.

A5 is the area of the landfill in square metres that has active gas collection and:

(a) a final cover of clay that is at least 1 metre thick; or

(b) a geo-membrane cover system.

(2) Where a landfill operator is unable to specify the areas for the factors A2, A3, A4 and A5 in subsection (1), the collection efficiency limit for the landfill is calculated using the following formula:

$$\text{Area of landfill in square metres with active gas collection} \times 75\%$$

Subdivision 5.2.3.2—Requirements for calculating the methane generation constant (k)

5.16 Procedures for selecting representative zone

The operator of the landfill must select a representative zone in accordance with sections 5.17 to 5.17B for the purpose of estimating the methane generated from the landfill.

5.17 Site plan—preparation and requirements

(1) Before selecting a representative zone, the operator of a landfill must prepare a site plan of the landfill.

(2) The site plan must:

(a) be consistent with the provisions relating to landfill site plans included in the document entitled *Technical Guidelines for the estimation of greenhouse gas emissions by facilities in Australia*, published by the Department of Climate Change and Energy Efficiency in July 2011; and

(b) if the landfill has more than one sub-facility zone—show the boundaries of each sub-facility zone.

Note: The *Technical Guidelines for the estimation of greenhouse gas emissions by facilities in Australia* are available at www.climatechange.gov.au.

5.17AA Sub-facility zones—maximum number and requirements

(1) After preparing a site plan, the landfill operator may select sub-facility zones for the site plan.

(2) The number of sub-facility zones the landfill operator may select:

(a) for sub-facility zones that contain only waste mix of the type mentioned in paragraph 5.11(1)(i)—is unlimited; and

(b) for all other sub-facility zones—must not exceed 4.

(3) A sub-facility zone:

(a) must cover an area of at least 1 hectare; and

(b) must be a single area within the landfill; and

(c) must have a uniform composition of waste mix types so that the estimates of the methane generated by the sub-facility zone are in accordance with section 1.13; and
(d) must not be subject to:
  (i) landfill gas inflow from another sub-facility zone; or
  (ii) landfill gas outflow to another sub-facility zone.

(4) At least one sub-facility zone must contain a representative zone.

Note: Section 5.22A sets out, for a landfill operator using method 1 in Division 5.2.2 to estimate emissions of methane released from legacy waste in a landfill, options and requirements related to sub-facility zones.

5.17A Representative zones—selection and requirements

After preparing a site plan, the operator of the landfill must select a representative zone that:

(a) covers an area of at least one hectare; and
(b) is a single area within the sub-facility zone; and
(c) has a uniform composition of waste mix types so that the estimates of the methane generated by the representative zone comply with section 1.13; and
(d) contains a number of operating gas collection wells that is sufficient to enable accurate and representative estimates of the methane being generated by the representative zone to be obtained; and
(e) contains only waste that has been undisturbed:
  (i) for at least 12 months before any methane generation is measured in accordance with section 5.17H; or
  (ii) if the representative zone is on landfill that recirculates leachate or adds moisture through the waste to promote methane generation—for the period determined by an independent expert; and
(f) has a low permeability basal liner that includes:
  (i) a compacted clay base; or
  (ii) a geomembrane base; or
  (iii) another demonstrated low permeability base; and
(g) is confined on:
  (i) 4 sides by low permeability barriers, including:
    (A) capped areas; or
    (B) a landfill cell lining; or
    (C) if the representative zone does not have a landfill cell lining—a demonstrated low gas permeability strata; or
  (ii) 3 sides by low permeability barrier and one side by an active gas collection system; and
(i) includes a gas extraction system that:
  (i) forms the boundary of the fourth side; and
  (ii) extends beyond the boundary of the representative zone; and
(j) has a top cover that is a final type or an intermediate type.

5.17B Independent verification

(1) After the operator of the landfill has selected a representative zone for a sub-facility zone, the operator of the landfill must arrange for an independent expert to certify, in writing, that:

  (a) the boundaries of the representative zone are appropriate for the purpose of obtaining accurate and representative estimates of the methane being generated by the representative zone; and

  (b) the representative zone is representative of the sub-facility zone.

(2) The independent expert must also prepare a written report for the zone.

(3) The report must include the details specified in the technical guidelines in relation to expert reports.

5.17C Estimation of waste and degradable organic content in representative zone

The amount of waste, and the amount of degradable organic content in the waste, disposed of in the representative zone must be estimated in accordance with sections 5.5 to 5.12 for each reporting year that waste is disposed of in the representative zone.

5.17D Estimation of gas collected at the representative zone

(1) The operator of the landfill must estimate the total amount, and concentration, of landfill gas measured in tonnes of methane per year collected by all of the landfill gas collection wells located within the representative zone.

(2) Measurement of the landfill gas flow rate for each well must be undertaken in accordance with Division 2.3.6.

(3) The methane concentration of the landfill gas from the representative zone:

  (a) may be estimated from measurements of landfill gas obtained at each gas collection well located within the representative zone using industry standard landfill gas analysers that are calibrated to the manufacturer’s specifications; or

  (b) may be assumed to be the methane concentration for the landfill as analysed under Subdivision 2.3.3.2.

(4) Data about the methane gas flow rates at each well in the representative zone must be:

  (a) the data used for operational purposes; and

  (b) recorded at least once a month for a period of at least 12 months.

(5) Fuel flow meter equipment and gas composition monitoring equipment used to measure and analyse the landfill gas must be calibrated in accordance with:

  (a) a standard specified in section 2.24 or an equivalent standard; or

  (b) the calibration procedures specified, and at the frequencies recommended, by the manufacturer of the equipment.

(6) Fuel flow meter equipment and gas composition monitoring equipment must be recalibrated:
  (a) at the frequency specified by the manufacturer of the equipment; or
  (b) if the manufacturer does not specify a recalibration period for the equipment—annually.

(7) Estimates of gas flow must be converted from cubic metres to mass by using the formula in subsection 1.21(1).

5.17E Estimating methane generated but not collected in the representative zone

(1) The operator must estimate the amount of emissions of methane in the representative zone that is not collected by the collection wells in the zone.

(2) Estimates must be obtained by using the procedures in sections 5.17F to 5.17H.

5.17F Walkover survey

(1) The operator of the landfill must arrange for an independent expert to conduct, at least every 3 months, a walkover survey of the representative zone using a portable gas measurement device in order to:
  (a) determine the near surface gas concentrations in the representative zone and in the immediately surrounding area; and
  (b) identify locations within the representative zone that have:
    (i) low methane emissions; and
    (ii) intermediate methane emissions; and
    (iii) elevated methane emissions; and
    (iv) high methane emissions; and
  (c) scan the representative zone by scanning along multiple transects that are less than 25 metres wide; and
  (d) if the scan detects an area within the representative zone that has high methane emissions—scan along multiple transects 1 metre wide; and
  (e) record the results; and
  (f) map the results against the site plan prepared in accordance with section 5.17.

(2) The portable gas measurement device must be capable of detecting hydrocarbons at 10 parts per million.

(3) In this section:

low methane emissions means methane emissions that the results of a scan performed in accordance with this section indicate are equal to or less than 50 parts per million.

intermediate methane emissions means emissions that the results of a scan performed in accordance with this section indicate are greater than 50 parts per million and equal to or less than 100 parts per million.

elevated methane emissions means methane emissions that the results of a scan performed in accordance with this section indicate are greater than 100 parts per million and less than 500 parts per million.

high methane emissions means methane emissions that the results of a scan performed in accordance with this section indicate are equal to or greater than 500 parts per million.

5.17G Installation of flux boxes in representative zone

(1) After the walkover survey has been completed, the operator of the landfill must arrange for the installation of flux boxes in the representative zone.

(2) The number of flux boxes must be at least the minimum number identified during the walkover survey.

(3) The flux boxes must be installed at the locations identified in the walkover survey.

(4) If the operator installs the flux boxes, the operator must ensure that an independent expert certifies, in writing, that the boxes have been correctly installed and located.

(5) If the operator arranges for some other person to install the flux boxes, the other person must be an independent expert.

(6) If an independent expert identifies an area within a representative zone that has low methane emissions, the landfill operator must:

(a) calculate the methane gas flow rate of the area by using a rate of 0.01g CH_4 per square metre per hour; or

(b) take all reasonable steps to ensure that the independent expert performs the calculation mentioned in paragraph (a).

(7) If an independent expert identifies an area within a representative zone that has intermediate methane emissions, the landfill operator must:

(a) calculate the methane gas flow rate of the area by using a rate of 0.12g CH_4 per square metre per hour; or

(b) take all reasonable steps to ensure that the independent expert performs the calculation mentioned in paragraph (a).

(8) If an independent expert identifies an area within a representative zone that has elevated methane emissions, the landfill operator must:

(a) calculate the methane gas flow rate for the area by using a rate of 4.3 g CH_4 per square metre per hour; or

(b) take all reasonable steps to ensure that the independent expert performs the calculation mentioned in paragraph (a); or

(c) take all reasonable steps to ensure that the independent expert works out the minimum number of flux boxes for the area by using the following formula:

$$2 + 0.15 \times \sqrt{Z}$$

where:

Z is the size of the area within the representative zone that has elevated methane emissions, measured in square metres.

(9) If an independent expert identifies an area within a representative zone that has high methane emissions, the landfill operator must:
- (a) calculate the methane gas flow rate of the area by using a rate of 75 g CH_4 per square metre per hour; or
- (b) take all reasonable steps to ensure that the independent expert performs the calculation mentioned in paragraph (a); or
- (c) take all reasonable steps to ensure that the independent expert works out the minimum number of flux boxes for the area by using the following formula:

$$2 + 0.15 \times \sqrt{Z}$$

where:

Z is the size of the area within the representative zone that has high methane emissions, measured in square metres.

(10) In this section:

low methane emissions means methane emissions that the results of a scan performed in accordance with this section indicate are equal to or less than 50 parts per million.

intermediate methane emissions means emissions that the results of a scan performed in accordance with this section indicate are greater than 50 parts per million and equal to or less than 100 parts per million.

elevated methane emissions means methane emissions that the results of a scan performed in accordance with this section indicate are greater than 100 parts per million and less than 500 parts per million.

high methane emissions means methane emissions that the results of a scan performed in accordance with this section indicate are equal to or greater than 500 parts per million.

5.17H Flux box measurements

(1) After the flux boxes have been installed in the representative zone, the operator must:
- (a) measure the flow of methane in each flux box and arrange for an independent expert to certify, in writing, that the measurements are accurate and were correctly measured; or
- (b) arrange for an independent expert to take the measurements.

Note: AS/NZS 4323.4—2009 and the publication entitled *Guidance on monitoring landfill gas surface emissions* published by the Environment Agency of the United Kingdom in September 2004 contain guidance on how to take measurements in flux boxes.

(2) The flow of methane from each flux box must be calculated in accordance with the following formula:

$$Q = \frac{V \times \left(\frac{dc}{dt}\right)}{A}$$

where:

Q is the flow density of the gas in the flux box, measured in milligrams of methane per square metre per second.

V is the volume of the flux box, measured in cubic metres.

$\boldsymbol{\frac{dc}{dt}}$ is the rate of change of gas concentration in the flux boxes over time, measured in milligrams per cubic metre per second.

A is the area covered by the flux box, measured in square metres.

(3) The total gas flow rate for the representative zone is to be obtained by using geospatial interpolation techniques.

(4) The amount of methane generated, but not collected, in the representative zone must be estimated by dividing the total gas flow rate obtained in accordance with subsection (3) by:

$$1 - OF$$

where:

OF is the oxidation factor mentioned in subsection 5.15(1).

(5) The measurement of methane obtained under the formula in subsection (2) must be converted from milligrams of methane per square metre per second to tonnes of methane for the surface area of the representative zone for the reporting year.

(6) Estimates of gas flow must be converted from cubic metres to mass by using the formula in subsection 1.21(1).

5.17I When flux box measurements must be taken

(1) Flux box measurements must be taken during the normal operating times of the gas collection wells in the representative zone.

(2) The measurements must be completed within 3 days.

5.17J Restrictions on taking flux box measurements

(1) Flux box measurements must not be taken:

  (a) within 2 days of heavy rainfall over the representative area; or

(b) if barometric pressure at the landfill site is rising or falling sharply; or

(c) during frost conditions; or

(d) in any other meteorological conditions that may significantly affect the accuracy of the measurements; or

(e) in areas where there is standing water.

Note: AS/NZS 4323.4—2009 and the publication entitled *Guidance on monitoring landfill gas surface emissions* published by the Environment Agency of the United Kingdom in September 2004 contain guidance on good measurement practice.

(2) For subsection (1), there is ***heavy rainfall*** over a representative area on any day of a month if the amount of rain that is recorded:

(a) at the landfill on that day; or

(b) if rainfall is not recorded at the landfill—at the nearest Bureau of Meteorology weather station to the landfill on that day;

exceeds the heavy rainfall benchmark, as calculated in accordance with the following formula:

$$\text{HRF} = 2 \times \frac{\text{RF}}{\text{MRD}}$$

where:

HRF is the heavy rainfall benchmark.

RF is the mean monthly rainfall for the month at the landfill or nearest Bureau of Meteorology weather station.

MRD is the mean rainfall days for the month at the nearest Bureau of Meteorology weather station as recorded in the publication published by the Bureau of Meteorology and known as *Climate statistics for Australian locations*.

5.17K Frequency of measurement

The measurement of emissions by flux boxes must be undertaken on a quarterly basis for a period of at least 12 months.

5.17L Calculating the methane generation constant (k_i) for certain waste mix types

(1) In this section:

k_i means the methane generation constant for each waste mix type:

(a) mentioned in column 3 of the table in subsection 5.14(6); and

(b) worked out by performing the steps set out in subsection (2).

Q_z means the gas flow rate for the representative zone.

CH_{4gen} is the quantity of methane generated by the landfill as calculated under this section and measured in CO_2-e tonnes.

(2) For subsection (1), the steps are.

Step 1 Identify the total amount of methane:

(a) estimated in accordance with section 5.17D; and

(b) collected at the gas collection wells in the representative zone.

Step 2 Identify the total amount of methane generated by the representative zone:

(a) measured in accordance with section 5.17H; and

(b) converted in accordance with subsection 5.17H(5).

Step 3 Identify Q_z by adding the amount identified under step 1 to the amount identified under step 2.

Step 4 Calculate CH_{4gen} to within ± 0.001 of Q_z, using the amount identified under step 3 and the equation mentioned in section 5.4D, by adjusting incrementally each default methane generation constant for each of those waste mix types using the following formula:

$$k_{iadj} = k_{idef} \times (1 + incr_{\%})$$

where:

k_{iadj} is the adjusted methane generation constant for each waste mix type mentioned in column 3 of the table in subsection 5.14(6).

k_{idef} is the default methane generation constant for each waste mix type mentioned in column 3 of the table in subsection 5.14(6).

$incr_{\%}$ is the incremental percentage (≤ 1%).

(3) For subsection (1):

(a) CH_{4gen} for each representative zone must be worked out:

(i) using the estimates mentioned in section 5.4A and the equations mentioned in sections 5.4B, 5.4C and 5.4D; and

(ii) for each waste mix type mentioned in column 3 of the table in subsection 5.14(6)—using the formula for calculating k_{iadj} and the method of working out k_i in this section; and

(b) it is sufficient if CH_{4gen} is within ± 0.001 of Q_z.

(4) Subsection (6) applies if:

(a) in the previous reporting year, a methane generation constant for each waste mix type mentioned in column 3 of a table in section 5.14 is selected from one of those tables for the purpose of estimating methane emissions from the solid waste located in a sub-facility zone; and

(b) k_i is worked out before 1 October 2013 for each waste mix type mentioned in column 3 of the table in subsection 5.14(6).

(5) However, subsection (6) does not apply to solid waste of a waste mix type mentioned in column 3 of the table in subsection 5.14(6) if:

(a) the waste has been deposited in a sub-facility zone; and

(b) a methane generation constant for the solid waste has been:

(i) estimated under method 2; and

(ii) used in the previous reporting year.

(6) For each waste mix type mentioned in column 3 of the table in subsection 5.14(6), k_i must be applied in the calculation of methane:

(a) generated from solid waste deposited in a representative zone in a reporting year; and

(b) generated from solid waste deposited in every sub-facility zone in each reporting year for which an independent expert has certified, in accordance with section 5.17B, that the representative zone is representative of the sub-facility zone; and

(c) if the methane is calculated using the estimates mentioned in paragraph 5.14A(a), (b), (c) or (d) and all of the following:

(i) the fraction of organic carbon dissimilated mentioned in column 3 of the table in section 5.14A;

(ii) the methane correction factor for aerobic decomposition mentioned in section 5.14B;

(iii) the fraction by volume of methane generated in landfill gas mentioned in section 5.14C.

Note 1: For provisions regarding the selection and requirements of representative zones, see sections 5.16 to 5.17I.

Note 2: Section 5.17AA sets out, for a landfill operator using method 2 in Division 5.2.3 or method 3 in Division 5.2.4, the number of sub-facility zones that the landfill operator may select and the requirements for sub-facility zones that the landfill operator must comply with.

Note 3: Section 5.22A sets out, for a landfill operator using method 1 in Division 5.2.2 to estimate emissions of methane released from legacy waste in a landfill, options and requirements related to sub-facility zones.

Division 5.2.4—Method 3—emissions of methane released from solid waste at landfills

5.18 Method 3—methane released from solid waste at landfills (other than from flaring of methane)

(1) For subparagraph 5.3(1)(a)(iii) and subject to subsection (2), method 3 is the same as method 2 under section 5.15.

(2) In applying method 2 under section 5.15, the gas flow rate must be estimated from sampling undertaken during the year in accordance with USEPA Method 2E—*Determination of landfill gas production flow rate*, as set out in Appendix A-1 of Title 40, Part 60 of the Code of Federal Regulations, United States of America, or an equivalent Australian or international standard.

Division 5.2.5—Solid waste at landfills—Flaring

5.19 Method 1—landfill gas flared

(1) For subparagraph 5.3(b)(i), method 1 is:

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

where:

$E_{j\ flared}$ is the emissions of gas type (***j***), being methane and nitrous oxide, released from the landfill from flaring of the methane in landfill gas during the year measured in CO_2-e tonnes.

Q_{flared} is the quantity of methane in landfill gas flared during the year measured in cubic metres in accordance with Division 2.3.6.

EC_i is the energy content factor of methane in landfill gas in gigajoules per cubic metre (see Schedule 1).

EF_{ij} is the relevant emission factor for gas type (***j***), being methane and nitrous oxide, from the combustion of landfill gas in kilograms of CO_2-e per gigajoule (see Schedule 1).

(2) For ***Q_{flared}*** in subsection (1), the methane in landfill gas is taken to constitute 50% of the landfill gas.

5.20 Method 2—landfill gas flared

(1) For subparagraph 5.3(1)(b)(ii) and subject to this section, method 2 is the same as method 1 under section 5.19.

(2) In applying method 1 under section 5.19, ***Q_{flared}*** must be determined in accordance with the sampling and analysis requirements in Subdivision 2.3.3.2 and the measurement requirements in Division 2.3.6.

5.21 Method 3—landfill gas flared

(1) For subparagraph 5.3(1)(b)(iii) and subject to this section, method 3 is the same as method 1 under section 5.19.

(2) In applying method 1 under section 5.19, ***Q_{flared}*** must be determined in accordance with the sampling and analysis requirements in Division 2.3.4 and the measurement requirements in Division 2.3.6.

Division 5.2.6—Biological treatment of solid waste

5.22 Method 1—emissions of methane and nitrous oxide from biological treatment of solid waste

(1) For subparagraph 5.3(1)(c)(i) and paragraph 5.3(1)(d), method 1 is:

$$E_{ij} = \left(M_i \times EF_i\right) - R$$

where:

EF_i is the emission factor for each gas type (j), being methane or nitrous oxide, released from the biological treatment type (i) measured in tonnes of CO_2-e per tonne of waste processed.

E_{ij} is the emissions of the gas type (j), being methane or nitrous oxide, released from the facility during the year from the biological treatment type (i) measured in CO_2-e tonnes.

M_i is the mass of waste treated by biological treatment type (i) during the year measured in tonnes of waste.

R is:

(a) for the gas type methane—the total amount of methane recovered during the year at the facility from the biological treatment of solid waste measured in tonnes of CO_2-e; or

(b) for the gas type nitrous oxide—zero.

(2) For EF_i in subsection (1), the emission factor for each gas type released from the biological treatment type is set out in the following table:

Emission factor for type of gas and biological treatment

Item	Biological treatment	Emission factor tonnes CO_2-e/tonne of waste treated	
		Methane	Nitrous Oxide
1	Composting at the facility	0.019	0.029
2	Anaerobic digestion at the facility	0.025	0

5.22AA Method 4—emissions of methane and nitrous oxide from biological treatment of solid waste

For subparagraph 5.3(1)(c)(ii), method 4 is as set out in Part 1.3.

Division 5.2.7—Legacy emissions and non-legacy emissions

5.22A Legacy emissions estimated using method 1—sub-facility zone options

(1) If a landfill operator estimates emissions of methane released from legacy waste in a landfill using method 1 in Division 5.2.2, the landfill operator may:
- (a) take the whole landfill to be a sub-facility zone; or
- (b) select sub-facility zones in accordance with subsections (2) and (3).

(2) The number of sub-facility zones the landfill operator may select:
- (a) for sub-facility zones that contain only waste mix of the type mentioned in paragraph 5.11(1)(i)—is unlimited; and
- (b) for all other sub-facility zones—must not exceed 4.

(3) A sub-facility zone:
- (a) must cover an area of at least 1 hectare; and
- (b) must be a single area within the landfill; and
- (c) must have a uniform composition of waste mix types so that the estimates of the methane generated by the sub-facility zone are in accordance with section 1.13; and
- (d) must not be subject to:
  - (i) landfill gas inflow from another sub-facility zone; or
  - (ii) landfill gas outflow to another sub-facility zone.

Note: Section 5.17AA sets out, for a landfill operator using method 2 in Division 5.2.3 or method 3 in Division 5.2.4, the number of sub-facility zones that the landfill operator may select and the requirements for sub-facility zones that the landfill operator must comply with.

5.22B Legacy emissions—formula and unit of measurement

(1) Emissions (the ***legacy emissions***) from legacy waste must be estimated in tonnes of CO_2-e using the following formula:

$$E_{lw} = \left[CH_{4genlw} - \gamma\left(Q_{caplw} + Q_{fllw} + Q_{trlw}\right)\right] \times \left(1 - OF\right)$$

where:

E_{lw} is the quantity of methane released by the landfill from legacy waste, measured in CO_2-e tonnes.

CH_{4genlw} is the quantity of methane generated from legacy waste, measured in CO_2-e tonnes.

γ is the factor 6.784 × 10-4 × 25 converting cubic metres of methane at standard conditions measured to CO_2-e tonnes.

Q_{caplw} is the quantity of methane captured for combustion from landfill legacy waste during a reporting year and estimated in accordance with section 5.22C.

Q_{fllw} is the quantity of methane flared from landfill legacy waste during the reporting year and estimated in accordance with section 5.22D.

Q_{trlw} is the quantity of methane captured for transfer out of the landfill from landfill legacy waste during the reporting year and estimated according to section 5.22E.

OF is the oxidation factor (0.1) for near surface methane in the landfill.

(2) Work out the ratio of methane generated by legacy waste deposited in a sub-facility zone to methane generated by all waste deposited in a sub-facility zone using the default ratio mentioned in subsection (3) or the method described in subsection (4).

Default ratios

(3) The default ratio of methane generated by landfill legacy waste deposited in a sub-facility zone to methane generated by all waste deposited in a sub-facility zone is:

(a) if all of the waste in the sub-facility zone is legacy waste—1; or

(b) if none of the waste in the sub-facility zone is legacy waste—0.

Method of working out ratio

(4) Work out the ratio of methane generated by legacy waste deposited in a sub-facility zone to methane generated by all waste deposited in a sub-facility zone using the following formula:

$$\mathrm{Lr_z} = \mathrm{CH_{4genlwz}} / \left(\mathrm{CH_{4genz}}\right)$$

where:

Lr_z is the ratio of methane generated by legacy waste deposited in a sub-facility zone to methane generated by all waste deposited in a sub-facility zone.

$CH_{4genlwz}$ is the quantity of methane generated from legacy waste in a sub-facility zone, measured in CO_2-e tonnes.

$CH4_{genz}$ is the methane generated from total waste deposited in a sub-facility zone, measured in CO_2-e tonnes.

5.22C How to estimate quantity of methane captured for combustion from legacy waste for each sub-facility zone

The quantity of methane captured for combustion from legacy waste during the reporting year for each sub-facility zone must be estimated using the following formula:

$$\mathrm{Q_{caplw\,z}} = \mathrm{Q_{cap\,z}} \times \mathrm{Lr_z}$$

where:

$Q_{caplw\,z}$ is the quantity of methane captured for combustion from landfill legacy waste in each sub-facility zone during a reporting year.

$Q_{cap\,z}$ is the total quantity of methane in landfill gas captured for combustion from the sub-facility zone during the reporting year, measured in cubic metres in accordance with Division 2.3.6.

Lr_z is the ratio of methane generated by legacy waste deposited in a sub-facility zone to methane generated by all waste deposited in a sub-facility zone.

5.22D How to estimate quantity of methane in landfill gas flared from legacy waste in a sub-facility zone

The quantity of methane in landfill gas flared from landfill legacy waste during the reporting year for each sub-facility zone must be estimated using the following formula:

$$Q_{fllw\,z} = Q_{fl\,z} \times Lr_z$$

where:

$Q_{fllw\,z}$ is the estimated quantity of methane in landfill gas flared from landfill legacy waste during the reporting year for each sub-facility zone.

$Q_{fl\,z}$ is the total quantity of methane in landfill gas flared from the sub-facility zone during the reporting year, measured in cubic metres in accordance with Division 2.3.6.

Lr_z is the ratio of methane generated by legacy waste deposited in a sub-facility zone to methane generated by all waste deposited in a sub-facility zone.

5.22E How to estimate quantity of methane captured for transfer out of landfill from legacy waste for each sub-facility zone

The quantity of methane captured for transfer out of the landfill from legacy waste for each sub-facility zone must be estimated using the following formula:

$$Q_{trlw\,z} = Q_{tr\,z} \times Lr_z$$

where:

$Q_{trlw\,z}$ is the estimated quantity of methane captured for transfer out of the landfill from legacy waste for each sub-facility zone.

$Q_{tr\,z}$ is the total quantity of methane in landfill gas transferred out of the sub-facility zone during the reporting year, measured in cubic metres in accordance with Division 2.3.6.

Lr_z is the ratio of methane generated by legacy waste deposited in a sub-facility zone to methane generated by all waste deposited in a sub-facility zone.

5.22F How to calculate the quantity of methane generated from legacy waste for a sub-facility zone ($CH_{4genlw\ z}$)

Calculate $CH_{4genlw\ z}$:

(a) using the estimates, equations and methods set out in sections 5.4 to 5.22K; and

(b) when using those estimates, equations and methods—by replacing:

- (i) waste deposited in a landfill with legacy waste deposited in a sub-facility zone; and
- (ii) the quantity of methane in landfill gas captured for combustion from the landfill with the quantity of methane in landfill gas captured for combustion from legacy waste in the sub-facility zone; and
- (iii) the quantity of methane in landfill gas flared from the landfill with the quantity of methane in landfill gas flared from legacy waste in the sub-facility zone; and
- (iv) the quantity of methane in landfill gas captured for transfer out of the landfill with the quantity of methane in landfill gas captured for transfer out of the landfill from legacy waste in the sub-facility zone.

5.22G How to calculate total methane generated from legacy waste

Total methane generated from legacy waste is equal to the sum of methane generated from legacy waste for all sub-facility zones and is calculated using the following formula:

$$CH_{4genlw} = \sum\nolimits_{z} CH_{4genlw\ z}$$

where:

$\boldsymbol{CH4_{genlw}}$ is the methane generated from legacy waste deposited at the landfill, measured in CO_2-e tonnes.

$\sum_z$ is the sum of all sub-facility zones.

$\boldsymbol{CH_{4genlw\ z}}$ is the quantity of methane generated from legacy waste in a sub-facility zone, measured in CO_2-e tonnes, calculated in accordance with section 5.22F.

5.22H How to calculate total methane captured and combusted from methane generated from legacy waste

Total methane captured and combusted from methane generated from legacy waste is equal to the sum of methane captured and combusted from methane generated from legacy waste for all sub-facility zones and is calculated using the following formula:

$$Q_{caplw} = \sum\nolimits_{z} Q_{caplw\ z}$$

where:

$\boldsymbol{Q_{caplw}}$ is the quantity of methane captured for combustion from landfill legacy waste during a reporting year.

$\sum_z$ is the sum of all sub-facility zones.

$Q_{caplw\,z}$ is the quantity of methane captured for combustion from each sub-facility zone during a reporting year, estimated in accordance with section 5.22C.

5.22J How to calculate total methane captured and transferred offsite from methane generated from legacy waste

Total methane captured and transferred offsite from methane generated from legacy waste is equal to the sum of methane captured and transferred offsite from methane generated from legacy waste for all sub-facility zones and is calculated using the following formula:

$$Q_{trlw} = \sum_z Q_{trlw\,z}$$

where:

Q_{trlw} is the total methane captured and transferred offsite from methane generated from legacy waste deposited at the landfill.

$\sum_z$ is the sum of all sub-facility zones.

$Q_{trlw\,z}$ is the estimated quantity of methane captured for transfer out of the landfill from legacy waste for each sub-facility zone, estimated in accordance with section 5.22E.

5.22K How to calculate total methane flared from methane generated from legacy waste

Total methane flared from methane generated from legacy waste is equal to the sum of methane flared from methane generated from legacy waste for all sub-facility zones and is calculated using the following formula:

$$Q_{fllw} = \sum_z Q_{fllw\,z}$$

where:

Q_{fllw} is the quantity of methane flared from landfill legacy waste during the reporting year.

$\sum_z$ is the sum of all sub-facility zones.

$Q_{fllw\,z}$ is the quantity of methane in landfill gas from landfill legacy waste for each sub-facility zone during the reporting year, estimated in accordance with section 5.22D.

5.22L How to calculate methane generated in landfill gas from non-legacy waste

(1) Methane generated in landfill gas from non-legacy waste must be calculated using the following formula:

$$CH_{4gennlw} = CH_{4genj} - CH_{4genlw}$$

where:

$CH_{4gennlw}$ is the methane generated in landfill gas from non-legacy waste, measured in CO_2-e tonnes.

CH_{4genj} is the methane generated in landfill gas from total waste deposited at the landfill, measured in CO_2-e tonnes.

$CH4_{genlw}$ is the methane generated in landfill gas from legacy waste deposited at the landfill, measured in CO_2-e tonnes.

(2) Emissions from non-legacy waste must be calculated using the following formula, measured in CO_2-e tonnes:

$$E_{nlw} = E_j - E_{lw}$$

where:

E_{nlw} are the emissions from non-legacy waste.

E_j is the quantity of methane from waste deposited at the landfill, measured in CO_2-e tonnes:

E_{lw} is the quantity of methane from legacy waste deposited at the landfill, measured in CO_2-e tonnes.

5.22M Calculating amount of total waste deposited at landfill

To calculate the amount of total waste deposited at a landfill, add the amount of legacy waste deposited at the landfill to the amount of non-legacy waste deposited at the landfill.

Part 5.3—Wastewater handling (domestic and commercial)

Division 5.3.1—Preliminary

5.23 Application

(1) This Part applies to emissions released from the decomposition of organic material, nitrification and denitrification processes, and flaring of sludge biogas, resulting from the handling of domestic or commercial wastewater through:

- (a) treatment in wastewater collection and treatment systems; or
- (b) discharge into surface waters.

(1A) However, this Part is not applicable to a person providing a report to the Regulator under the Act whose primary activities lie outside of item 192, Water supply, sewerage and drainage services (ANZSIC code 281), in Schedule 2 of the Regulations.

(2) In this section, ***domestic or commercial wastewater*** means liquid wastes and sludge (including human waste) from housing or commercial premises.

5.24 Available methods

(1) Subject to section 1.18, for estimating emissions released from the operation of a facility that is constituted by wastewater handling (domestic and commercial) (the ***plant***) during a year:

- (a) one of the following methods must be used for emissions of methane from the plant (other than from flaring of methane):
  - (i) method 1 under section 5.25;
  - (ii) method 2 under section 5.26;
  - (iii) method 3 under section 5.30; and
- (b) one of the following methods must be used for emissions of nitrous oxide from the plant (other than from flaring of methane):
  - (i) method 1 under section 5.31;
  - (ii) method 2 under section 5.32;
  - (iii) method 3 under section 5.36; and
- (c) one of the following methods must be used for emissions for each gas type as a result of methane flared from the plant:
  - (i) method 1 under section 5.37;
  - (ii) method 2 under section 5.38;
  - (iii) method 3 under section 5.39.

(2) Under paragraph (1)(c), the same method must be used for estimating emissions of each gas type.

(3) For incidental emissions another method may be used that is consistent with the principles in section 1.13.

Note: There is no method 4 for paragraphs (1)(a), (b) and (c).

Division 5.3.2—Method 1—methane released from wastewater handling (domestic and commercial)

5.25 Method 1—methane released from wastewater handling (domestic and commercial)

(1) For subparagraph 5.24(1)(a)(i), method 1 is:

$$E_j = \left[CH_4^* - \gamma(Q_{cap} + Q_{flared} + Q_{tr})\right]$$

where:

E_j is the emissions of methane released by the plant during the year measured in CO_2-e tonnes.

CH_4^* is the estimated quantity of methane in sludge biogas released by the plant during the year measured in CO_2-e tonnes as determined under subsections (2) and (3).

γ is the factor 6.784 x 10^{-4} x 25 converting cubic metres of methane at standard conditions to CO_2-e tonnes.

Q_{cap} is the quantity of methane in sludge biogas captured for combustion for use by the plant during the year measured in cubic metres in accordance with Division 2.3.6.

Q_{flared} is the quantity of methane in sludge biogas flared during the year by the plant measured in cubic metres in accordance with Division 2.3.6.

Q_{tr} is the quantity of methane in sludge biogas transferred out of the plant during the year measured in cubic metres in accordance with Division 2.3.6.

(2) For subsection (1), if:

$$\frac{\gamma\ (Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

is less than or equal to 0.75, then:

$$CH_4^* = CH_{4gen}$$

where:

CH_{4gen} is the quantity of methane in sludge biogas produced by the plant during the year, estimated in accordance with subsection (5) and measured in CO_2-e tonnes.

(3) For subsection (1), if:

$$\frac{\gamma\,(Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

is greater than 0.75, then:

$$CH_4^* = \gamma\left(Q_{cap} + Q_{flared} + Q_{tr}\right) \times \left(\frac{1}{0.75}\right)$$

where:

γ is the factor 6.784 x 10^{-4} x 25 converting cubic metres of methane at standard conditions to CO_2-e tonnes.

Q_{cap} is the quantity of methane in sludge biogas captured for combustion by the plant, measured in cubic metres in accordance with Division 2.3.6.

(4) For subsections (1) and (3), ***Q_{cap}*** is to be calculated in accordance with Division 2.3.6.

(5) For subsection (2):

$$CH_{4gen} = \left[(COD_w - COD_{sl} - COD_{eff}) \times MCF_{ww} \times EF_{wij}\right] + \left[(COD_{sl} - COD_{trl} - COD_{tro}) \times MCF_{sl} \times EF_{slij}\right]$$

where:

COD_W is the factor worked out as follows:

$$COD_w = P \times DC_w$$

where:

P is the population served by the operation of the plant during the year and measured in numbers of persons.

DC_w is the quantity in tonnes of COD per capita of wastewater for a year using a default of 0.0585 tonnes per person.

CH_{4gen} is the methane generated from commercial wastewater and sludge treatment by the plant during the year measured in CO_2-e tonnes.

COD_w is the chemical oxygen demand (***COD***) in wastewater entering the plant during the year measured in tonnes.

COD_{sl} is the quantity of COD removed as sludge from wastewater and treated in the plant measured in tonnes of COD and worked out as follows:

$$COD_{sl} = COD_{psl} + COD_{wasl}$$

where:

$\boldsymbol{COD_{psl}}$ is the quantity of COD removed as primary sludge from wastewater and treated in the plant measured in tonnes of COD and estimated under subsection (7).

$\boldsymbol{COD_{wasl}}$ is the quantity of COD removed as waste activated sludge from wastewater and treated in the plant measured in tonnes of COD and estimated under subsection (8).

$\boldsymbol{COD_{eff}}$ is the quantity of COD in effluent leaving the plant during the year measured in tonnes.

$\boldsymbol{MCF_{ww}}$ is the methane correction factor for wastewater treated at the plant during the year.

Note: IPCC default methane correction factors for various types of treatment 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.

$\boldsymbol{EF_{wij}}$ is the default methane emission factor for wastewater with a value of 6.3 CO_2-e tonnes per tonne COD.

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

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

$\boldsymbol{MCF_{sl}}$ is the methane correction factor for sludge treated at the plant during the year.

Note: IPCC default methane correction factors for various types of treatment 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.

$\boldsymbol{EF_{slij}}$ is the default methane emission factor for sludge with a value of 6.3 CO_2-e tonnes per tonne COD (sludge).

(6) For subsection (5), an operator of the plant must choose a treatment for $\boldsymbol{MCF_{ww}}$ and estimate the quantity of COD removed from the wastewater as sludge $(\boldsymbol{COD_{sl}})$.

(7) For subsection (5), COD_{psl} may be estimated using the following formula:

$$VS_{psl} \times 1.99$$

where:

$\boldsymbol{VS_{psl}}$ is the estimated volatile solids in the primary sludge.

(8) For subsection (5), COD_{wasl} may be estimated using the following formula:

$$VS_{wasl} \times 1.48$$

where:

VS_{wasl} is the estimated volatile solids in the waste activated sludge.

(9) In this section:

methane correction factor is the fraction of COD anaerobically treated.

primary sludge means sludge from the first major treatment process in a wastewater treatment facility that is designed primarily to remove a substantial amount of suspended matter but little or no colloidal or dissolved matter.

waste activated sludge means sludge from a secondary treatment process in a wastewater treatment facility involving aeration and active biological material.

Division 5.3.3—Method 2—methane released from wastewater handling (domestic and commercial)

5.26 Method 2—methane released from wastewater handling (domestic and commercial)

(1) Method 2 is:

Step 1. Calculate the amount of emissions of methane released for each sub-facility of a plant during the reporting year, measured in CO_2-e tonnes, using the equation:

$$CH_{4genz} - \gamma\left(Q_{capz} + Q_{flaredz} + Q_{trz}\right)$$

where:

γ is the factor 6.784 x 10^{-4} x 25 for converting cubic metres of methane at standard conditions to CO_2-e tonnes.

$\boldsymbol{CH_{4genz}}$ is the estimated quantity of methane in sludge biogas generated by the sub-facility during the reporting year, worked out in accordance with subsection (2), measured in CO_2-e tonnes.

$\boldsymbol{Q_{capz}}$ is the quantity of methane in sludge biogas that is captured for combustion by the sub-facility during the reporting year, measured in cubic metres in accordance with Division 2.3.6.

$\boldsymbol{Q_{flaredz}}$ is the quantity of methane in sludge biogas flared by the sub-facility during the reporting year, measured in cubic metres in accordance with Division 2.3.6.

$\boldsymbol{Q_{trz}}$ is the quantity of methane in sludge biogas transferred out of the plant during the reporting year by the sub-facility, measured in cubic metres in accordance with Division 2.3.6.

Note: For the number of sub-facilities a plant operator may select and requirements in relation to each sub-facility, see section 5.26A.

Step 2. To calculate the amount of methane emissions released by the plant during the reporting year, measured in CO_2-e tonnes, add together the amount worked out for each sub-facility under step 1.

(2) Subject to subsection (8), the factor $\boldsymbol{CH_{4genz}}$ in subsection (1) is worked out for a sub-facility as follows:

Step 1. Calculate the following for the sub-facility:

$$\frac{\gamma\left(Q_{capz} + Q_{flaredz} + Q_{trz}\right)}{\left[\begin{array}{l}\left(COD_{wz} - COD_{slz} - COD_{effz}\right) \times MCF_{wwz} \times EF_{wijz} + \\ \left(COD_{slz} - COD_{trlz} - COD_{troz}\right) \times MCF_{slz} \times EF_{slijz}\end{array}\right]}$$

where:

γ has the same meaning as in step 1 in subsection (1).

COD_{effz} is the quantity of COD in effluent leaving the sub-facility during the reporting year, measured in tonnes of COD and calculated by using:

(a) facility operating data that measures the volumetric effluent rate and the effluent rate of COD concentration; or

(b) if data is available on the biochemical oxygen demand (***BOD***) in the effluent—that data converted to COD in accordance with the following formula:

$$COD = 2.6 \times BOD_5$$

COD_{slz} is the quantity of COD removed as sludge from wastewater and treated in the sub-facility, measured in tonnes of COD and worked out using the formula mentioned in subsection (4).

COD_{trlz} is the quantity of COD in sludge transferred out of the sub-facility and removed to landfill, measured in tonnes of COD.

COD_{troz} is the quantity of COD in sludge transferred out of the sub-facility and removed to a site other than landfill, measured in tonnes of COD.

COD_{wz} is the quantity of COD in wastewater entering the sub-facility during the year, measured in tonnes of COD and calculated by using:

(a) facility operating data that measures the volumetric influent rate and the influent rate of COD concentration; or

(b) if data is available on the biochemical oxygen demand (***BOD***) in the wastewater—that data converted to COD in accordance with the following formula:

$$\text{COD} = 2.6 \times \text{BOD}_5$$

$\boldsymbol{EF_{slijz}}$ is the default methane emission factor for sludge with a value of 6.3 CO_2-e tonnes per tonne of COD (sludge).

$\boldsymbol{EF_{wijz}}$ is the default methane emission factor for wastewater with a value of 6.3 CO_2-e tonnes per tonne of COD.

$\boldsymbol{MCF_{slz}}$ is the methane correction factor for sludge treated at the sub-facility during the reporting year.

$\boldsymbol{MCF_{wwz}}$ is the methane correction factor for wastewater treated at the sub-facility during the reporting year.

$\boldsymbol{Q_{capz}}$ has the same meaning as in step 1 in subsection (1).

$\boldsymbol{Q_{flaredz}}$ has the same meaning as in step 1 in subsection (1).

$\boldsymbol{Q_{trz}}$ has the same meaning as in step 1 in subsection (1).

Step 2. If the quantity worked out under step 1 is less than or equal to 1.00, work out $\boldsymbol{CH_{4genz}}$ using the following formula:

$$\left(\text{COD}_{\text{wz}} - \text{COD}_{\text{slz}} - \text{COD}_{\text{effz}}\right) \times \text{MCF}_{\text{wwz}} \times \text{EF}_{\text{wijz}} + \left(\text{COD}_{\text{slz}} - \text{COD}_{\text{trlz}} - \text{COD}_{\text{troz}}\right) \times \text{MCF}_{\text{slz}} \times \text{EF}_{\text{slijz}}$$

where:

$\boldsymbol{COD_{effz}}$ has the same meaning as in step 1.

$\boldsymbol{COD_{slz}}$ has the same meaning as in step 1.

$\boldsymbol{COD_{trlz}}$ has the same meaning as in step 1.

$\boldsymbol{COD_{troz}}$ has the same meaning as in step 1.

$\boldsymbol{COD_{wz}}$ has the same meaning as in step 1.

$\boldsymbol{EF_{slijz}}$ has the same meaning as in step 1.

$\boldsymbol{EF_{wijz}}$ has the same meaning as in step 1.

$\boldsymbol{MCF_{wwz}}$ has the same meaning as in step 1.

$\boldsymbol{MCF_{slz}}$ has the same meaning as in step 1.

Step 3. If the quantity worked out under step 1 is greater than 1.00, work out CH_{4genz} using the formula:

$$\gamma\left(Q_{capz} + Q_{flaredz} + Q_{trz}\right) \times \left(\frac{1}{1.00}\right)$$

where:

γ has the same meaning as in step 1 in subsection (1).

Q_{capz} has the same meaning as in step 1 in subsection (1).

$Q_{flaredz}$ has the same meaning as in step 1 in subsection (1).

Q_{trz} has the same meaning as in step 1 in subsection (1).

(3) For steps 1 and 2 in subsection (2), an operator of the plant must choose a treatment for MCF_{wwz} and estimate the quantity of COD removed from the wastewater as sludge (COD_{slz}).

(4) For steps 1 and 2 in subsection (2), COD_{slz} is worked out using the formula:

$$COD_{pslz} + COD_{waslz}$$

where:

COD_{pslz} is the quantity of COD removed as primary sludge from wastewater and treated in the sub-facility measured in tonnes of COD and may be estimated using the formula in subsection (5).

COD_{waslz} is the quantity of COD removed as waste activated sludge from wastewater and treated in the sub-facility measured in tonnes of COD and may be estimated using the formula in subsection (6).

(5) For subsection (4), COD_{pslz} may be estimated in accordance with the following formula:

$$VS_{pslz} \times 1.99$$

where:

VS_{pslz} is the estimated volatile solids in the primary sludge.

(6) For subsection (4), COD_{waslz} may be estimated in accordance with the following formula:

$$VS_{waslz} \times 1.48$$

where:

VS_{waslz} is the estimated volatile solids in the waste activated sludge.

(7) Wastewater used for the purposes of subsection (2) must be sampled and analysed for COD in accordance with the requirements in sections 5.27, 5.28 and 5.29.

(8) If the sub-facility is an anaerobic sludge lagoon, the method set out in the document entitled “Fugitive Emissions from Sludge Lagoons Technical Paper”, published by the Water Services Association of Australia in April 2014, may be used to estimate CH_{4genz} for the sub-facility.

Note: The *Fugitive Emissions from Sludge Lagoons Technical Paper* could in 2014 be viewed on the Water Services Association of Australia’s website (http://www.wsaa.asn.au).

(9) In this section:

methane correction factor is the fraction of COD anaerobically treated.

Note: IPCC default methane correction factors for various types of treatment are as follows:
(a) managed aerobic treatment: 0;
(b) unmanaged aerobic treatment: 0.3;
(c) anaerobic digester/reactor: 0.8;
(d) shallow anaerobic lagoon (<2 metres): 0.2;
(e) deep anaerobic lagoon (>2 metres): 0.8.

primary sludge means sludge from the first major treatment process in a wastewater treatment facility that is designed primarily to remove a substantial amount of suspended matter but little or no colloidal or dissolved matter.

waste activated sludge means sludge from a secondary treatment process in a wastewater treatment facility involving aeration and active biological material.

5.26A Requirements relating to sub-facilities

(1) A plant operator may select one or more sub-facilities for the plant to estimate emissions released by the plant.

(2) A sub-facility selected:
    (a) must be an area within a plant covering a discrete treatment stage; and
    (b) must have a uniform treatment of COD so that the estimates of the methane generated by the sub-facility are consistent with the principles mentioned in section 1.13; and
    (c) must not be subject to:
        (i) sludge biogas inflow from another sub-facility; or
        (ii) sludge biogas outflow to another sub-facility.

5.27 General requirements for sampling under method 2

(1) A sample must be representative of the wastewater and the COD concentrations at the plant.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias may be tested in accordance with an appropriate standard (if any).

(5) The value obtained from the sample must only be used for the plant for which it was intended to be representative.

5.28 Standards for analysis

(1) Samples of wastewater must be analysed for COD in accordance with:
   (a) ISO 6060:1989; or
   (b) sections 5220B, 5220C or 5220D of APHA (1995); or
   (c) an equivalent Australian or international standard.

(2) Samples of wastewater must be analysed for BOD in accordance with:
   (a) AS 4351.5—1996; or
   (b) section 5210B of APHA (1995); or
   (c) an equivalent Australian or international standard.

5.29 Frequency of sampling and analysis

Wastewater must be sampled and analysed on at least a monthly basis.

Division 5.3.4—Method 3—methane released from wastewater handling (domestic and commercial)

5.30 Method 3—methane released from wastewater handling (domestic and commercial)

(1) For subparagraph 5.24(a)(iii) and subject to subsection (2), method 3 is the same as method 2 under section 5.26.

(2) In applying method 2 under section 5.26, the wastewater must be sampled in accordance with AS/NZS 5667.10:1998 or an equivalent Australian or international standard.

Division 5.3.5—Method 1—emissions of nitrous oxide released from wastewater handling (domestic and commercial)

5.31 Method 1—nitrous oxide released from wastewater handling (domestic and commercial)

(1) For paragraph 5.24(1)(b), method 1 is:

$$E_j = (N_{in} - N_{trl} - N_{tro} - N_{outdisij}) \times EF_{secij} + N_{outdisij} \times EF_{disij}$$

where:

E_j is the emissions of nitrous oxide released from human sewage treated by the plant during the year, measured in tonnes of nitrous oxide and expressed in CO_2-e tonnes.

N_in is the quantity of nitrogen entering the plant during the year, measured in tonnes of nitrogen and worked out:

(a) for primary wastewater treatment plants, using the following formula:

$$N_{in} = N_{trl} + N_{tro} + N_{outdisij}$$

where:

N_trl is the quantity of nitrogen in sludge transferred out of the plant and removed to landfill during the year, measured in tonnes of nitrogen and worked out using the following formula:

$$N_{trl} = F_{Ntrl} \times M_{trl}$$

N_tro is the quantity of nitrogen in sludge transferred out of the plant and removed to a site other than landfill during the year, measured in tonnes of nitrogen and worked out as follows:

$$N_{tro} = F_{Ntro} \times M_{tro}$$

N_outdisij is the quantity of nitrogen leaving the plant, differentiated by discharge environment; or

(b) for any other kind of wastewater treatment plant, using the following formula:

$$N_{in} = Protein \times Frac_{Pr} \times P$$

where:

Protein is the annual per capita protein intake of the population being served by the plant, measured in tonnes per person.

Frac_Pr is the fraction of nitrogen in protein.

P is the population serviced by the plant during the year.

N_{trl} is the quantity of nitrogen in sludge transferred out of the plant and removed to landfill during the year, measured in tonnes of nitrogen and worked out as follows:

$$N_{trl} = F_{Ntrl} \times M_{trl}$$

where:

F_{Ntrl} is the fraction of nitrogen in the sludge transferred out of the plant.

M_{trl} is the dry mass of sludge transferred out of the plant to landfill during the year, measured in tonnes.

N_{tro} is the quantity of nitrogen in sludge transferred out of the plant and removed to a site other than landfill during the year, measured in tonnes of nitrogen and worked out as follows:

$$N_{tro} = F_{Ntro} \times M_{tro}$$

where:

F_{Ntro} is the fraction of nitrogen in the sludge transferred out of the plant to a site other than landfill.

M_{tro} is the dry mass of sludge transferred out of the plant to a site other than landfill during the year, measured in tonnes.

$N_{outdisij}$ is the quantity of nitrogen leaving the plant, differentiated by discharge environment.

EF_{secij} is the emission factor for wastewater treatment.

EF_{disij} is the emission factor for nitrogen discharge, differentiated by the discharge environment.

(2) For ***Protein*** in subsection (1), the annual per capita protein intake is 0.036 tonnes per year.

(3) For $Frac_{Pr}$ in subsection (1), the factor is 0.16 tonnes of nitrogen per tonne of protein.

(4) For F_{Ntrl} and F_{Ntro} in subsection (1), the factor is 0.05.

(5) For $N_{outdisij}$ in subsection (1), discharge environments mentioned in column 2 of an item of the following table are defined in column 3 for the item.

Item	Discharge environment	Definition
1	***Enclosed waters***	All waters other than open coastal waters or estuarine waters
2	***Estuarine waters***	All waters (other than open coastal waters) that are: (a) ordinarily subject to tidal influence; and (b) enclosed by a straight line drawn between the low water marks of consecutive headlands

Item	Discharge environment	Definition
3	***Open coastal waters (ocean and deep ocean)***	(a) for New South Wales—has the meaning given by the definition of ***open coastal waters*** in Schedule 3 to the *Protection of the Environment Operations (General) Regulation 2009* (NSW), as in force on 8 June 2012; and (b) otherwise—means all waters of the Pacific Ocean, Southern Ocean and Indian Ocean, except those waters enclosed by a straight line drawn between the low water marks of consecutive headlands

Note: Historical versions of the *Protection of the Environment Operations (General) Regulation 2009* (NSW) are available at www.legislation.nsw.gov.au.

(6) For $\boldsymbol{EF_{secij}}$ in subsection (1), the emission factor is 4.9 tonnes of nitrous oxide, measured in CO_2-e per tonne of nitrogen produced.

(7) For $\boldsymbol{EF_{disij}}$ in subsection (1), the emission factor mentioned in column 3 of an item of the following table must be used for the discharge environment mentioned in column 2 for the item.

Item	Discharge environment	$\boldsymbol{EF_{disij}}$
1	Enclosed waters	4.7
2	Estuarine waters	1.2
3	Open coastal waters (ocean and deep ocean)	0.0

Division 5.3.6—Method 2—emissions of nitrous oxide released from wastewater handling (domestic and commercial)

5.32 Method 2—nitrous oxide released from wastewater handling (domestic and commercial)

(1) For subparagraph 5.24(1)(b)(ii) and subject to this section, method 2 is the same as method 1 under section 5.31.

(2) In applying method 1 under section 5.31, nitrogen must be calculated:

(a) by using facility operating data that measures the volumetric influent and effluent rates and the influent and effluent rates of nitrogen concentrations; or

(b) for primary wastewater treatment plants, using the following formula:

$$N_{in} = N_{trl} + N_{tro} + N_{outdisij}$$

where:

N_{in} is the quantity of nitrogen entering the plant during the year, measured in tonnes of nitrogen.

N_{trl} is the quantity of nitrogen in sludge transferred out of the plant and removed to landfill during the year, measured in tonnes of nitrogen and worked out using the following formula:

$$N_{trl} = F_{Ntrl} \times M_{trl}$$

N_{tro} is the quantity of nitrogen in sludge transferred out of the plant and removed to a site other than landfill during the year, measured in tonnes of nitrogen and worked out as follows:

$$N_{tro} = F_{Ntro} \times M_{tro}$$

$N_{outdisij}$ is the quantity of nitrogen leaving the plant, differentiated by discharge environment.

(3) Wastewater used for the purposes of subsection (2), must be sampled and analysed for nitrogen in accordance with the requirements in sections 5.33, 5.34 and 5.35.

5.33 General requirements for sampling under method 2

(1) A sample must be representative of the wastewater and the nitrogen concentrations at the plant.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard (if any).

(5) The value obtained from the sample must only be used for the plant for which it was intended to be representative.

5.34 Standards for analysis

(1) Samples of wastewater must be analysed for nitrogen in accordance with:
- (a) ISO 11905-1:1997; or
- (b) sections 4500-N_{org} B, 4500-N_{org} C or 4500-N_{org} D of APHA (1995); or
- (c) an equivalent Australian or international standard.

(2) Samples of sludge must be analysed for nitrogen in accordance with:
- (a) EN 13342:2000; or
- (b) section 4500-N_{org} B of APHA (1995); or
- (c) an equivalent Australian or international standard.

5.35 Frequency of sampling and analysis

Wastewater must be sampled and analysed on at least a monthly basis.

Division 5.3.7—Method 3—emissions of nitrous oxide released from wastewater handling (domestic and commercial)

5.36 Method 3—nitrous oxide released from wastewater handling (domestic and commercial)

(1) For subparagraph 5.24(1)(b)(iii) and subject to subsection (2), method 3 is the same as method 2 under section 5.32.

(2) In applying method 2 under section 5.32, the wastewater must be sampled in accordance with AS/NZS 5667.10:1998 or an equivalent Australian or international standard.

(3) In applying method 2 under section 5.32, the sludge must be sampled in accordance with ISO 5667-13:1997 or an equivalent Australian or international standard.

Division 5.3.8—Wastewater handling (domestic and commercial)—Flaring

5.37 Method 1—Flaring of methane in sludge biogas from wastewater handling (domestic and commercial)

(1) For subparagraph 5.24(1)(c)(i), method 1 is:

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

where

E$_{j\ flared}$ is the emissions of gas type (***j***) released from the plant from flaring of the methane in sludge biogas from the plant during the year measured in CO_2-e tonnes.

Q$_{flared}$ is the quantity of methane in sludge biogas flared from the plant during the year measured in cubic metres in accordance with Division 2.3.6.

EC$_i$ is the energy content factor of methane in sludge biogas in gigajoules per cubic metre (see Schedule 1).

EF$_{ij}$ is the relevant emission factor for gas type (***j***) for methane in sludge biogas measured in CO_2-e per gigajoule (see Schedule 1).

(2) For ***Q$_{flared}$*** in subsection (1), the methane in sludge biogas is taken to constitute 70% of the sludge biogas.

5.38 Method 2—flaring of methane in sludge biogas

(1) For subparagraph 5.24(1)(c)(ii) and subject to this section, method 2 is the same as method 1 under section 5.37.

(2) In applying method 1 under section 5.37, ***Q$_{flared}$*** must be determined in accordance with the sampling and analysis requirements in Subdivision 2.3.3.2 and the measuring requirements in Division 2.3.6.

5.39 Method 3—flaring of methane in sludge biogas

(1) For subparagraph 5.24(1)(c)(iii) and subject to this section, method 3 is the same as method 1 under section 5.37.

(2) In applying method 1 under section 5.37, ***Q$_{flared}$*** must be determined in accordance with the sampling and analysis requirements in Division 2.3.4 and the measuring requirements in Division 2.3.6.

Part 5.4—Wastewater handling (industrial)

Division 5.4.1—Preliminary

5.40 Application

(1) This Part applies to emissions released from the decomposition of organic material and the flaring of sludge biogas, resulting from the handling of industrial wastewater through treatment in wastewater collection and treatment systems.

(2) In this section, ***industrial wastewater*** means liquid wastes and sludge resulting from the production of a commodity, by an industry, mentioned in column 1 of an item of the table in subsection 5.42(8).

5.41 Available methods

(1) Subject to section 1.18 one of the following methods must be used for estimating emissions of methane released from the operation of a facility (other than by flaring of landfill gas containing methane) that is constituted by wastewater handling generated by the relevant industries (the ***plant)*** during a year:
  (a) method 1 under section 5.42;
  (b) method 2 under section 5.43;
  (c) method 3 under section 5.47.

(2) Subject to section 1.18, one of the following methods must also be used for estimating emissions of each gas type released as a result of methane in sludge biogas flared from the operation of the plant during a year:
  (a) method 1 under section 5.48;
  (b) method 2 under section 5.49;
  (c) method 3 under section 5.50.

(3) Under subsection (2), the same method must be used for estimating emissions of each gas type.

(4) For incidental emissions another method may be used that is consistent with the principles in section 1.13.

Note: There is no method 4 for subsection (1) or (2).

Division 5.4.2—Method 1—methane released from wastewater handling (industrial)

5.42 Method 1—methane released from wastewater handling (industrial)

(1) For paragraph 5.41(1)(a), method 1 is:

$$E_j = \left[CH_4^* - \gamma(Q_{cap} + Q_{flared} + Q_{tr})\right]$$

where:

E_j is the emissions of methane released from the plant during the year measured in CO_2-e tonnes.

CH_4^* is the estimated quantity of methane in sludge biogas generated by the plant during the year measured in CO_2-e tonnes as determined under subsections (2) and (3).

γ is the factor $6.784 \times 10^{-4} \times 25$ converting cubic metres of methane at standard conditions to CO_2-e tonnes.

Q_{cap} is the quantity of methane in sludge biogas captured for combustion for the plant during the year measured in cubic metres in accordance with Division 2.3.6.

Q_{flared} is the quantity of methane in sludge biogas flared by the plant during the year measured in cubic metres in accordance with Division 2.3.6.

Q_{tr} is the quantity of methane in sludge biogas transferred out of the plant during the year measured in cubic metres in accordance with Division 2.3.6.

(2) For subsection (1), if:

$$\frac{\gamma\ (Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

is less than or equal to 0.75, then:

$$CH_4^* = CH_{4gen}$$

where:

CH_{4gen} is the quantity of methane in sludge biogas produced by the plant during the year, estimated in accordance with subsection (5) and measured in CO_2-e tonnes.

(3) For subsection (1), if:

$$\frac{\gamma\ (Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

is greater than 0.75, then:

$$CH_4^* = \gamma\left(Q_{cap} + Q_{flared} + Q_{tr}\right) \times \left(\frac{1}{0.75}\right)$$

where:

γ is the factor 6.784 x 10^{-4} x 25 converting cubic metres of methane at standard conditions to CO_2-e tonnes.

Q_{cap} is the quantity of methane in sludge biogas captured for combustion for the operation of the plant measured in cubic metres.

(4) For subsections (1) and (3), ***Q_{cap}*** is to be calculated in accordance with Division 2.3.6.

(5) For subsection (2) the factor ***CH_{4gen}*** is estimated as follows:

$$CH_{4gen} = \left(\sum_{w,i} COD_{w,i} - COD_{sl} - COD_{eff}\right) \times MCF_{ww} \times EF_{wij} + \left(COD_{sl} - COD_{trl} - COD_{tro}\right) \times MCF_{sl} \times EF_{slij}$$

where:

$\Sigma_{w,i}$ 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 any commodity mentioned in column 1 of the table in subsection (8) during the year measured in tonnes of COD, worked out as follows:

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

where:

$Prod_i$ has the meaning given by the table in subsection 5.42(9).

$W_{gen,i}$ is the wastewater generation rate from the production of any commodity mentioned in column 1 of the table in subsection (8) 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 any commodity mentioned in column 1 of the table in subsection (8).

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 any commodity mentioned in column 1 of the table in subsection (8) 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.

COD_{eff} is the quantity of COD effluent leaving the plant during the year, measured in tonnes.

MCF_{ww} is the methane correction factor for wastewater treated at the plant during the year.

Note: IPCC default methane correction factors for various types of treatment 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.

EF_{wij} is the methane emission factor for industrial wastewater.

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.

MCF_{sl} is the methane correction factor for sludge treated at the plant during the year.

Note: IPCC default methane correction factors for various types of treatment 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.

EF_{slij} is the methane emission factor for the treatment of sludge by the plant.

(6) For EF_{wij} in subsection (5), an emission factor of 6.3 CO2-e tonnes per tonne of COD may be used.

(7) For EF_{slij} in subsection (5), a methane emission factor of 6.3 CO_2-e tonnes per tonne of COD may be used.

(8) For subsection (5), COD must be estimated for a commodity set out in column 1 of an item in the following table that is produced by the industry referred to by the ANZSIC code set out in column 1 for that item:

(a) by using the default values for $W_{gen,i}$ and $COD_{con,i}$ set out in columns 2 and 3 for that item; or

(b) in accordance with industry practice relevant to the measurement of the quantity of wastewater.

Estimate of COD for a commodity and industry

Item	Column 1 Commodity and industry	Column 2 $W_{gen,i}$ default value	Column 3 $COD_{con,i}$ default value
1	Dairy product (ANZSIC code 113)	5.7	0.9
2	Pulp, paper and paperboard (ANZSIC code 1510)	26.7	0.4
3	Meat and poultry (ANZSIC codes 1111 and 1112)	13.7	6.1
4	Organic chemicals (ANZSIC codes 18 and 19)	67.0	3.0
5	Raw sugar (ANZSIC code 1181)	0.4	3.8
6	Beer (ANZSIC code 1212)	5.3	6.0
7	Wine and other alcoholic beverage (ANZSIC code 1214)	23.0	1.5
8	Fruit and vegetable (ANZSIC code 1140)	20.0	0.2

(9) For subsection (5), $\boldsymbol{Prod_i}$ is the amount of any commodity set out in column 2 of an item in the following table, produced by the industry set out in column 2 for that item, and measured in accordance with the corresponding units of measurement set out in column 3 for that item.

Item	Commodity and industry	Units of measurement
1	Dairy product (ANZSIC code 113)	tonne of product
2	Pulp, paper and paperboard (ANZSIC code 1510)	tonne of product
3	Meat and poultry (ANZSIC codes 1111 and 1112)	tonne of product
4	Organic chemicals (ANZSIC codes 18 and 19)	tonne of product
5	Raw sugar (ANZSIC code 1181)	tonne of product
6	Beer (ANZSIC code 1212)	tonne of product
7	Wine and other alcoholic beverage (ANZSIC code 1214)	tonne of product
8	Fruit and vegetable (ANZSIC code 1140)	tonne of product

(10) In this section:

methane correction factor is the fraction of COD anaerobically treated.

Division 5.4.3—Method 2—methane released from wastewater handling (industrial)

5.43 Method 2—methane released from wastewater handling (industrial)

(1) For paragraph 5.41(1)(b) and subject to this section, method 2 for wastewater handling (industrial) is the same as method 1 under section 5.42.

(2) In applying method 1 under section 5.42, each mention of $\boldsymbol{COD_{w,i}}$ in subsection 5.42(5) must be estimated from wastewater entering the plant and must be calculated by using:

(a) facility operating data that measures the volumetric influent rate and the influent rate of COD concentrations; or

(b) if data is available on the biochemical oxygen demand (***BOD***) in the wastewater—that data converted to COD in accordance with the following formula:

$$\text{COD} = 2.6 \times \text{BOD}_5$$

(2A) In applying method 1 under section 5.42, the reference to 0.75 in subsections 5.42(2) and (3) is to read as a reference to 1.00.

(3) Wastewater used for the purposes of subsection (2), must be sampled and analysed for COD in accordance with the requirements in sections 5.44, 5.45 and 5.46.

5.44 General requirements for sampling under method 2

(1) A sample must be representative of the wastewater and the COD concentrations at the plant.

(2) The samples must be collected on enough occasions to produce a representative sample.

(3) The samples must also be free of bias so that any estimates are neither over nor under estimates of the true value.

(4) Bias must be tested in accordance with an appropriate standard (if any).

(5) The value obtained from the sample must only be used for the plant for which it was intended to be representative.

5.45 Standards for analysis

(1) Samples of wastewater must be analysed for COD in accordance with:

(a) ISO 6060:1989; or

(b) sections 5220B, 5220C or 5220D of APHA (1995); or

(c) an equivalent Australian or international standard.

(2) Samples of wastewater must be analysed for BOD in accordance with:
  (a) AS 4351.5—1996; or
  (b) section 5210B of APHA (1995); or
  (c) an equivalent Australian or international standard.

5.46 Frequency of sampling and analysis

Wastewater must be sampled and analysed on at least a monthly basis.

Division 5.4.4—Method 3—methane released from wastewater handling (industrial)

5.47 Method 3—methane released from wastewater handling (industrial)

(1) For paragraph 5.41(1)(c) and subject to subsection (2), method 3 is the same as method 2 under section 5.43.

(2) In applying method 2 under section 5.43, the wastewater must be sampled in accordance with AS/NZS 5667.10:1998 or an equivalent Australian or international standard.

Division 5.4.5—Wastewater handling (industrial)—Flaring of methane in sludge biogas

5.48 Method 1—flaring of methane in sludge biogas

(1) For paragraph 5.41(2)(a), method 1 is:

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

where:

E_{j}* 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 CO_2-e tonnes.

Q_{flared} is the quantity of methane in sludge biogas flared by the plant during the year measured in cubic metres in accordance with Division 2.3.6.

EC_i is the energy content factor of methane in sludge biogas measured in gigajoules per cubic metre (see Schedule 1).

EF_{ij} is the relevant emission factor for gas type (***j***) for methane in sludge biogas in CO_2-e tonnes per gigajoule (see Schedule 1).

(2) For ***Q_{flared}*** in subsection (1), the methane in sludge biogas is taken to constitute 70% of the sludge biogas.

5.49 Method 2—flaring of methane in sludge biogas

(1) For paragraph 5.41(2)(b) and subject to this section, method 2 is the same as method 1 under section 5.48.

(2) In applying method 1 under section 5.48, ***Q_{flared}*** must be determined in accordance with the sampling and analysis requirements in Subdivision 2.3.3.2 and the measuring requirements in Division 2.3.6.

5.50 Method 3—flaring of methane in sludge biogas

(1) For paragraph 5.41(2)(c) and subject to this section, method 3 is the same as method 1 under section 5.48.

(2) In applying method 1 under section 5.48, ***Q_{flared}*** must be determined in accordance with the sampling and analysis requirements in Division 2.3.4 and the measuring requirements in Division 2.3.6.

Part 5.5—Waste incineration

5.51 Application

This Part applies to emissions released from waste incineration, other than incineration for energy production.

5.52 Available methods—emissions of carbon dioxide from waste incineration

(1) Subject to section 1.18, one of the following methods must be used for estimating emissions of carbon dioxide released from the operation of a facility that is constituted by waste incineration (the ***plant***):

- (a) method 1 under section 5.53;
- (b) method 4 under Part 1.3.

Note: There is no method 2 or 3 for this section.

(2) For incidental emissions, another method may be used that is consistent with the principles in section 1.13.

5.53 Method 1—emissions of carbon dioxide released from waste incineration

(1) Method 1 is:

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

where:

$\boldsymbol{E_i}$ is the emissions of carbon dioxide released from the incineration of waste type (***i***) by the plant during the year measured in CO_2-e tonnes.

$\boldsymbol{Q_i}$ is the quantity of waste type (***i***) incinerated by the plant during the year measured in tonnes of wet weight value in accordance with:

- (a) Division 2.2.5 for solid fuels; and
- (b) Division 2.3.6 for gaseous fuels; and
- (c) Division 2.4.6 for liquid fuels.

$\boldsymbol{CC_i}$ is the carbon content of waste type (***i***).

$\boldsymbol{FCC_i}$ is the proportion of carbon in waste type (***i***) that is of fossil origin.

$\boldsymbol{OF_i}$ is the oxidation factor for waste type (***i***).

(2) If waste materials other than clinical wastes have been incinerated by the plant, appropriate values for the carbon content of the waste material incinerated must be derived from Schedule 3.

(3) For $\boldsymbol{CC_i}$ in subsection (1), the IPCC default of 0.60 for clinical waste must be used.

(4) For $\boldsymbol{FCC_i}$ in subsection (1), the IPCC default of 0.40 for clinical waste must be used.

(5) For $\boldsymbol{OF_i}$ in subsection (1), the IPCC default of 1.00 for clinical waste must be used.

Chapter 6—Energy

Part 6.1—Production

6.1 Purpose

The purpose of this Part is to provide for the estimation of the energy content of energy produced from the operation of a facility during a year.

Note 1: Energy produced from the operation of a facility is dealt with in regulation 2.25 of the Regulations.

Note 2: Energy includes the fuels and energy commodities listed in Schedule 1 to the Regulations. See the definition of ***energy*** in section 7 of the Act and in regulation 2.03 of the Regulations.

6.2 Quantity of energy produced

(1) The quantity of an energy produced from the operation of the facility during the year must be estimated:

(a) if the energy is a solid fuel, gaseous fuel, sulphur, uranium or hydrogen—in accordance with industry practice; or

(b) if the energy is a liquid fuel—by either of the following:

(i) using bulk filling meters corrected to 15° celsius;

(ii) by the physical measurement of the fuel corrected to its notional volumetric equivalent at a temperature of 15° Celsius; or

(c) if the energy is electricity produced for use during the operation of the facility—as the difference between:

(i) the amount of electricity produced by the electricity generating unit for the facility as measured at the unit's terminals; and

(ii) the sum of the amounts of electricity supplied to an electricity transmission or distribution network measured at the connection point for the network in accordance with either of the measurement requirements specified in subsection (3) and the amount of electricity supplied for use outside the operation of the facility that is not supplied to the network; or

(d) if the energy is electricity produced for use outside the operation of the facility other than for supply to an electricity transmission network or distribution network—as the amount of electricity supplied for use outside the operation of the facility that is not supplied to an electricity transmission or distribution network; or

(e) if the energy is electricity supplied to an electricity transmission or distribution network—as the amount of electricity for use outside the operation of the facility for supply to the network measured at the connection point for the network in accordance with either of the measurement requirements specified in subsection (3).

Note: Energy includes the fuels and energy commodities listed in Schedule 1 to the Regulations. See the definition of ***energy*** in section 7 of the Act and regulation 2.03 of the Regulations.

(1A) For incidental energy production, another method may be used that is consistent with the principles in section 1.13.

(2) For subsection (1), if the fuel is coal, its quantity must be estimated in the form of saleable coal on a washed basis.

(3) For paragraphs (1)(c) and (e), the measurement requirements are as follows:

(a) Chapter 7 of the *National Electricity Rules* made under the National Electricity Law set out in the *National Electricity (South Australia) Act 1996*;

(b) metering requirements applicable to the region in which the facility is located.

6.3 Energy content of fuel produced

(1) The energy content of a kind of energy (***fuel***), other than sulphur, uranium or hydrogen, produced from the operation of the facility during the year is to be worked out as follows:

$$Z_i = Q_i \times EC_i$$

where:

$\boldsymbol{Z_i}$ is the energy content of fuel type (***i***) produced during the year and measured in gigajoules.

$\boldsymbol{Q_i}$ is the quantity of fuel type (***i***) produced during the year.

$\boldsymbol{EC_i}$ is the energy content factor of fuel type (***i***), measured as energy content according to the fuel type measured in gigajoules:

(a) as mentioned in Schedule 1; or

(b) in accordance with Divisions 2.2.3 and 2.2.4 (solid fuels), Divisions 2.3.3 and 2.3.4 (gaseous fuels) or Divisions 2.4.3 and 2.4.4 (liquid fuels); or

(c) for electricity measured in kilowatt hours, $\boldsymbol{EC_i}$ is equal to 0.0036; or

(d) for fuels measured in gigajoules, $\boldsymbol{EC_i}$ is equal to 1.

Note: Energy includes the fuels and energy commodities listed in Schedule 1 to the Regulations. See the definition of ***energy*** in section 7 of the Act and regulation 2.03 of the Regulations.

(2) The amount of electricity produced from the operation of the facility during the year must be evidenced by invoices, contractual arrangements or industry metering records.

Sulphur, uranium or hydrogen

(3) The energy content of sulphur, uranium or hydrogen produced from the operation of the facility during the year is worked out using the following formula:

$$Z = Q \times EC$$

where:

EC is the energy content factor of sulphur, uranium or hydrogen (whichever is applicable) mentioned in Part 7 of Schedule 1, measured in gigajoules per tonne.

Q is the quantity of sulphur, uranium or hydrogen (whichever is applicable) produced during the year and measured in tonnes.

Z is the energy content of sulphur, uranium or hydrogen (whichever is applicable) produced during the year and measured in gigajoules.

Part 6.2—Consumption

6.4 Purpose

The purpose of this Part is to provide for the estimation of the energy content of energy consumed from the operation of a facility during a year.

Note 1: Energy includes the fuels and energy commodities listed in Schedule 1 to the Regulations. See the definition of ***energy*** in section 7 of the Act and regulations 2.03 of the Regulations.

Note 2: Energy consumed from the operation of a facility is dealt with in regulation 2.26 of the Regulations.

Note 3: Energy consumed is subject to the thresholds mentioned in sections 2.2, 2.18 and 2.39 of this Determination.

6.5 Energy content of energy consumed

(1) The energy content of a kind of energy (***fuel)***, other than sulphur, uranium or hydrogen, consumed from the operation of the facility during the year is to be worked out as follows:

$$Z_i = Q_i \times EC_i$$

where:

Z_i is the energy content of fuel type (***i***) consumed during the year and measured in gigajoules.

Q_i is the quantity of fuel type (***i***) consumed during the year estimated in accordance with:

- (a) Parts 2.2 (solid fuels), 2.3 (gaseous fuels) and 2.4 (liquid fuels); or
- (b) subsection (2) for electricity.

EC_i, is the energy content factor of fuel type ***(i)*** and is:

- (a) for solid fuels, measured in gigajoules per tonne:
  - (i) as mentioned in Part 1 of Schedule 1; or
  - (ii) estimated by analysis of the fuel in accordance with the standard indicated for that energy content factor in Schedule 2 or an equivalent standard; or
- (b) for gaseous fuels, measured in gigajoules per cubic metre:
  - (i) as mentioned in Part 2 of Schedule 1; or
  - (ii) estimated by analysis under Subdivision 2.3.3.2; or
- (c) for gaseous fuels measured in gigajoules—equal to 1; or
- (d) for liquid fuels, measured in gigajoules per kilolitre:
  - (i) as mentioned in Part 3 of Schedule 1 for stationary energy purposes; or

(ii) as mentioned in Division 4.1 of Schedule 1 for transport energy purposes; or

(iii) estimated by analysis under Subdivision 2.4.3.2; or

(e) for electricity measured in kilowatt hours—equal to 0.0036.

Note: Energy includes the fuels and energy commodities listed in Schedule 1 to the Regulations. See the definition of ***energy*** in section 7 of the Act and regulation 2.03 of the Regulations.

(1A) Despite subsection (1), if:

(a) the kind of energy is one of the following:

(i) solar energy for electricity generation;

(ii) wind energy for electricity generation;

(iii) water energy for electricity generation;

(iv) geothermal energy for electricity generation; and

(b) the energy is consumed from the operation of the facility during the year; and

(c) from that consumption of energy, electricity is produced from the operation of the facility during the year;

then the energy content of the consumed energy is taken to be equal to the energy content of the electricity produced as estimated under Part 6.1.

(2) The amount of electricity consumed from the operation of the facility during the year must be:

(a) evidenced by invoices, contractual arrangements or industry metering records; or

(b) estimated in accordance with industry practice, if the evidence under paragraph (a) is unavailable.

(3) If, in relation to a year:

(a) a method used by a person requires the $\boldsymbol{EC_i}$ factor to be estimated under this section in relation to a particular fuel type ($\boldsymbol{i}$); and

(b) a way of estimating is chosen for the fuel type as required by this section; and

(c) other methods used by the person for the same fuel type also require the $\boldsymbol{EC_i}$ factor to be estimated under this section;

then the chosen way of estimating, and the amount estimated, must also be applied in using the other methods for the fuel type in relation to that year.

Sulphur, uranium or hydrogen

(4) The energy content of sulphur, uranium or hydrogen consumed from the operation of the facility during the year is worked out using the following formula:

$$Z = Q \times EC$$

where:

EC is the energy content factor of sulphur, uranium or hydrogen (whichever is applicable) mentioned in Part 7 of Schedule 1, measured in gigajoules per tonne.

Q is the quantity of sulphur, uranium or hydrogen (whichever is applicable) consumed during the year and measured in tonnes.

Z is the energy content of sulphur, uranium or hydrogen (whichever is applicable) consumed during the year and measured in gigajoules.

Chapter 7—Scope 2 emissions

7.1 Application

(1) This Chapter specifies a method of determining scope 2 emissions from the consumption of purchased electricity, or the loss of electricity from an electricity transmission network or distribution network.

(2) This Chapter applies if the amount of purchased electricity consumed from the operation of a facility during a year that results in scope 2 emissions is more than 20 000 kilowatt hours.

Note: Scope 2 emissions result from activities that generate electricity, heating, cooling or steam that is consumed by a facility but that do not form part of the facility (see regulation 2.24 of the Regulations).

7.2 Method 1—purchase and loss of electricity from main electricity grid in a State or Territory

(1) The following method must be used for estimating scope 2 emissions released from electricity purchased from the main electricity grid in a State or Territory and consumed from the operation of a facility during a year:

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

where:

Y is the scope 2 emissions measured in CO_2-e tonnes.

Q is the quantity of electricity purchased from the electricity grid during the year and consumed from the operation of the facility measured in kilowatt hours.

EF is the scope 2 emission factor, in kilograms of CO_2-e emissions per kilowatt hour, for the State or Territory in which the consumption occurs as mentioned in Part 6 of Schedule 1.

Note: There is no other method for this section.

(1A) The method in subsection (1) must, subject to subsection (2), also be used for estimating scope 2 emissions released from electricity consumed from the operation of a facility during a year if the operation of the facility is constituted by an electricity transmission network or distribution network that is, or is part of, the main electricity grid in a State or Territory.

(2) In applying that method for the purposes of subsection (1A), ***Q*** is the quantity of electricity losses for that network during the year.

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

(4) The ***main electricity grid***, for a State or Territory, means:
  (a) for Western Australia—the Southwest Interconnected System; and
  (b) for each other State or Territory—the electricity grid that provides electricity to the largest percentage of the State's or Territory's population.

7.3 Method 1—purchase and loss of electricity from other sources

(1) The following formula must be used for estimating scope 2 emissions released from electricity:
  (a) purchased from a grid other than the main electricity grid in a State or Territory; and
  (b) consumed from the operation of a facility during a year:

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

where:

Y is the scope 2 emissions measured in CO_2-e tonnes during the year.

Q is the quantity of electricity purchased during the year and consumed from the operation of the facility, measured in kilowatt hours.

EF is the scope 2 emission factor, in kilograms of CO_2-e emissions per kilowatt hour, either:
  (a) provided by the supplier of the electricity; or
  (b) if that factor is not available, the emission factor for the Northern Territory as mentioned in Part 6 of Schedule 1.

Note: There is no other method for this section.

(1A) The formula in subsection (1) must, subject to subsection (2), also be used for estimating scope 2 emissions released from electricity consumed from the operation of facility during a year if the operation of the facility is constituted by an electricity transmission network or distribution network that is not, and is not part of, the main electricity grid in a State or Territory.

(2) In applying that formula for the purposes of subsection (1A), ***Q*** is the quantity of electricity losses for that network during the year.

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

Chapter 8—Assessment of uncertainty

Part 8.1—Preliminary

8.1 Outline of Chapter

(1) This Chapter sets out rules about how uncertainty is to be assessed in working out estimates of scope 1 emissions for a source.

(2) Part 8.2 sets out general rules for assessing uncertainty of scope 1 emissions estimates.

(3) Part 8.3 sets out how to assess the uncertainty of estimates of scope 1 emissions that have been estimated using method 1.

(4) Part 8.4 sets out how to assess the uncertainty of estimates of scope 1 emissions that have been estimated using method 2, 3 or 4.

(5) Emissions estimates for a source that are calculated using method 1, 2 or 3 are a function of a number of parameters. The uncertainty of the emissions estimates consists of the uncertainty associated with each of these parameters, which may include one or more of the following parameters:

(a) energy content factor;
(b) emissions factor;
(c) activity data.

Note: In the case of fuel combustion, activity data refers to the quantity of fuel combusted. In the case of industrial processes, activity data refers to the quantity of product consumed or produced, as appropriate.

(6) Estimates of emissions need only provide for statistical uncertainty.

Note: The uncertainty protocol provides information about the assessment of uncertainty.

Part 8.2—General rules for assessing uncertainty

8.2 Range for emission estimates

Uncertainty must be assessed so that the range for an emissions estimate encompasses the actual amount of the emissions with 95% confidence.

8.3 Required method

(1) Uncertainty of estimates of scope 1 emissions must be assessed in accordance with Part 8.3 or with the uncertainty protocol, as appropriate.

(2) For corporations that have sources of scope 1 emissions that are estimated using a variety of method 1, 2, 3 or 4, the uncertainty associated with the emissions must be aggregated in accordance with section 8 of the uncertainty protocol.

Part 8.3—How to assess uncertainty when using method 1

8.4 Purpose of Part

This Part sets out how to assess uncertainty of scope 1 emissions if method 1 is used to estimate scope 1 emissions for a source.

8.5 General rules about uncertainty estimates for emissions estimates using method 1

The total uncertainty of scope 1 emissions estimates for a source in relation to a registered corporation is to be worked out by aggregating, as applicable, the uncertainty of the emissions factor, the energy content factor and the activity data for the source in accordance with the formula in section 8.11.

Note: This is generally referred to as the aggregated uncertainty for the source.

8.6 Assessment of uncertainty for estimates of carbon dioxide emissions from combustion of fuels

(1) In assessing uncertainty of the estimates of carbon dioxide emissions estimated using method 1 for a source that involves the combustion of a fuel, the assessment must include the statistical uncertainty associated with the following parameters:

- (a) the energy content factor of the fuel (as specified in column 3 of the following table or as worked out in accordance with item 1, 2 or 3 of section 7 of the uncertainty protocol);
- (b) the carbon dioxide emission factor of the fuel (as specified in column 4 of the following table or as worked out in accordance with item 1, 2 or 3 of section 7 of the uncertainty protocol);
- (c) the quantity of fuel combusted (as worked out in accordance with subsection (3) or as worked out in accordance with item 1, 2 or 3 of section 7 of the uncertainty protocol).

Item	**Fuel Combusted**	**Energy content uncertainty level (%)**	**Carbon dioxide emission factor uncertainty level (%)**
1	Bituminous coal	28	5
1A	Sub-bituminous coal	28	5
1B	Anthracite	28	5
2	Brown coal	50	12
3	Coking coal	12	7

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Item	Fuel Combusted	Energy content uncertainty level (%)	Carbon dioxide emission factor uncertainty level (%)
4	Coal briquettes	40	11
5	Coal coke	9	11
6	Coal tar	50	17
7	Solid fossil fuels other than those mentioned in items 1 to 5	50	15
8	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	50	26
9	Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	50	26
10	Dry wood	50	NA
11	Green and air-dried wood	50	NA
12	Sulphite lyes	50	NA
13	Bagasse	50	NA
14	Biomass municipal and industrial materials, if recycled and combusted to produce heat or energy	50	NA
15	Charcoal	50	NA
16	Primary solid biomass fuels other than those mentioned in items 10 to 15	50	NA
17	Natural gas if distributed in a pipeline	4	4
18	Coal seam methane that is captured for combustion	4	4
19	Coal mine waste gas that is captured for combustion	4	4
20	Compressed natural gas that has reverted to standard conditions	4	4
21	Unprocessed natural gas	4	4
22	Ethane	4	10
23	Coke oven gas	50	19
24	Blast furnace gas	50	17
25	Town gas	4	4
26	Liquefied natural gas	7	4
27	Gaseous fossil fuels other than those mentioned in items 17 to 26	50	10
28	Landfill biogas that is captured for combustion (methane only)	50	NA
29	Sludge biogas that is captured for combustion (methane only)	50	NA
30	A biogas that is captured for combustion, other than those mentioned in items 28 and 29 (methane only)	50	NA
31	Petroleum based oils (other than petroleum based oils used as fuel)	11	2

Item	Fuel Combusted	Energy content uncertainty level (%)	Carbon dioxide emission factor uncertainty level (%)
32	Petroleum based greases	11	2
33	Crude oil including crude oil condensates	6	3
34	Other natural gas liquids	7	9
35	Gasoline (other than for use as fuel in an aircraft)	3	4
36	Gasoline for use as fuel in an aircraft	3	4
37	Kerosene (other than for use as fuel in an aircraft)	3	2
38	Kerosene for use as fuel in an aircraft	3	3
39	Heating oil	5	2
40	Diesel oil	2	2
41	Fuel oil	2	2
42	Liquefied aromatic hydrocarbons	5	2
43	Solvents if mineral turpentine or white spirits	18	2
44	Liquid petroleum gas	8	3
45	Naphtha	5	5
46	Petroleum coke	19	17
47	Refinery gas and liquids	19	18
48	Refinery coke	19	17
49	Petroleum based products other than: (a) petroleum based oils and petroleum based greases mentioned in items 31 and 32; and (b) the petroleum based products mentioned in items 33 to 48	18	2
50	Biodiesel	50	NA
51	Ethanol for use as a fuel in an internal combustion engine	50	NA
52	Biofuels other than those mentioned in items 50 and 51	50	NA

(2) In the table in subsection (1), ***NA*** means not applicable.

(3) For a fuel type specified in column 2 of an item of the following table:

(a) column 3 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion A in Chapter 2; and

(b) column 4 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion AA in Chapter 2; and

(c) column 5 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion AAA in Chapter 2; and

(d) column 6 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion BBB in Chapter 2.

Note: Division 2.2.5 sets out the relevant criteria for solid fuels; Division 2.3.6 sets out the relevant criteria for gaseous fuels; and Division 2.4.6 sets out the relevant criteria for liquid fuels.

Item	**Fuel type**	**Uncertainty levels for quantities of fuel combusted (%)**			
		Criterion used for estimation of quantity of fuel combusted			
		A	**AA**	**AAA**	**BBB**
1	Solid fuel	2.5	2.5	1.5	7.5
2	Liquid fuel	1.5	1.5	1.5	7.5
3	Gaseous fuel	1.5	1.5	1.5	7.5

8.7 Assessment of uncertainty for estimates of methane and nitrous oxide emissions from combustion of fuels

(1) In assessing uncertainty of the estimates of methane and nitrous oxide emissions estimated using method 1 for a source that involves the combustion of a fuel specified in column 2 of an item in the table in subsection 8.6(1):

  (a) the uncertainty level of the energy content factor is:
    (i) as specified in column 3 for the item; or
    (ii) as worked out in accordance with section 7 of the uncertainty protocol; and
  (b) the uncertainty level of the emissions factor is:
    (i) 50%; or
    (ii) as worked out in accordance with section 7 of the uncertainty protocol.

(2) In assessing uncertainty of the estimates of methane and nitrous oxide emissions estimated using method 1 for a source that involves the combustion of a fuel type specified in column 2 of an item in the table in subsection 8.6(3):

  (a) column 3 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion A in Chapter 2; and
  (b) column 4 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion AA in Chapter 2; and
  (c) column 5 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion AAA in Chapter 2; and
  (d) column 6 for the item sets out the uncertainty level for the estimated quantities of fuel combusted using criterion BBB in Chapter 2.

Note: Division 2.2.5 sets out the relevant criteria for solid fuels; Division 2.3.6 sets out the relevant criteria for gaseous fuels; and Division 2.4.6 sets out the relevant criteria for liquid fuels.

8.8 Assessment of uncertainty for estimates of fugitive emissions

The aggregated uncertainty of the estimates of fugitive emissions estimated using method 1 for a source mentioned in column 2 of an item of the following table is:

  (a) as specified in column 3 for the item; or

(b) as worked out in accordance with the uncertainty protocol.

Item	**Sources**	**Aggregated uncertainty level (%)**
1	Underground mines	50
2	Open cut mines	50
3	Decommissioned underground mines	50
4	Oil or gas exploration	50
5	Crude oil production	50
6	Crude oil transport	50
7	Crude oil refining	50
8	Natural gas production or processing (other than emissions that are flared)	50
9	Natural gas transmission	50
10	Natural gas distribution	50
11	Natural gas production or processing—flaring	25

8.9 Assessment of uncertainty for estimates of emissions from industrial process sources

(1) In assessing uncertainty of the estimates of emissions estimated using method 1 for the industrial process sources mentioned in column 2 of an item of the following table, the assessment must include the uncertainty level for the emission factor and activity data associated with the source:

(a) as specified:

(i) for the emission factor—in column 3 for the item; and

(ii) for the activity data—in column 4 for the item; or

(b) as worked out in accordance with the uncertainty protocol.

Item	**Industrial process sources**	**Emission factor uncertainty level (%)**	**Activity data uncertainty (%)**
1	Cement clinker production	6	1.5
2	Lime production	6	1.5
3	Soda ash use	5	1.5
4	Use of carbonates for the production of a product other than cement clinker, lime or soda ash	5	1.5
5	Nitric acid production	40	1.5
6	Adipic acid production	10	1.5
7	Aluminium (carbon anode consumption)	5	1
8	Aluminium production (perfluoronated carbon compound emissions)	6	1

(2) In assessing uncertainty of the estimates of emissions estimated using method 1 for industrial process sources mentioned in column 2 of an item of the following table, column 3 for the item sets out the aggregated uncertainty level associated with the source.

Item	Industrial process sources	Aggregated uncertainty level (%)
1	Emissions of hydrofluorocarbons and sulphur hexafluoride gas	30

(3) The uncertainty of estimates of emissions for industrial process sources that are not mentioned in subsections (1) or (2) must be assessed:

(a) if the industrial process source involves the combustion of fuel—in accordance with: (i) for carbon dioxide emissions—section 8.6; and

(ii) for methane and nitrous oxide emissions—section 8.7; and

(b) if the industrial process source does not involve the combustion of fuel—in accordance with the uncertainty protocol.

8.10 Assessment of uncertainty for estimates of emissions from waste

In assessing uncertainty of the estimates of emissions from waste estimated using method 1 for the activities mentioned in column 2 of an item of the following table, the assessment must include the aggregated uncertainty level:

(a) as specified in column 3 for the item; or

(b) as worked out in accordance with the uncertainty protocol.

Item	Activities	Aggregated uncertainty level (%)
1	Solid waste disposal on land	35
2	Wastewater handling (industrial)	65
3	Wastewater handling (domestic or commercial)	40
4	Waste incineration	40

8.11 Assessing uncertainty of emissions estimates for a source by aggregating parameter uncertainties

(1) For section 8.5 and subject to subsections (2) and (3), in assessing uncertainty of the estimates of scope 1 emissions that are estimated using method 1 for a source, the aggregated uncertainty for emissions from the source is to be worked out in accordance with the following formula:

$$D = \pm\sqrt{A^2 + B^2 + C^2}$$

where:

D is the aggregated percentage uncertainty for the emission source.

A is the uncertainty associated with the emission factor for the source, expressed as a percentage.

B is the uncertainty associated with the energy content factor for the source, expressed as a percentage.

C is the uncertainty associated with the activity data for the source, expressed as a percentage.

(2) If an assessment of uncertainty of emissions for the source does not require the use of emissions factor uncertainty, energy content factor uncertainty or activity data uncertainty, then A, B or C, as appropriate, in the formula in subsection (1) is taken to be zero.

Example: If energy content factor uncertainty is not required for an industrial process source, then B would be taken to be zero in the formula in subsection (1) when assessing the aggregated uncertainty for the source.

(3) Subsection (1) does not apply to:

(a) estimates of fugitive emissions that are assessed by using the aggregated uncertainty level in column 3 of the table in section 8.8; or

(b) estimates of emissions from industrial processes that are assessed by using the aggregated uncertainty level in column 3 of the table in subsection 8.9(2); or

(c) estimates of emissions from waste activities that are assessed by using the aggregated uncertainty level in column 3 of the table in section 8.10.

Part 8.4—How to assess uncertainty levels when using method 2, 3 or 4

8.14 Purpose of Part

This Part sets out rules that apply in the assessment of uncertainty of scope 1 emissions for a source that are estimated using method 2, 3 or 4.

8.15 Rules for assessment of uncertainty using method 2, 3 or 4

(1) Subject to this section:
  (a) the uncertainty of the following must be assessed in accordance with the uncertainty protocol:
    (i) scope 1 emissions estimates that are estimated using method 2, 3 or 4;
    (ii) scope 1 fugitive emissions estimates for open cut coal mines that are estimated using method 4; and
  (b) the uncertainty of scope 1 fugitive emissions estimates for open cut coal mines that are estimated using method 2 or 3 must be:
    (i) assessed in accordance with the uncertainty protocol; and
    (ii) estimated using the method included in section 5 of the ACARP Guidelines.

(2) Item 4 of Part 7 of the uncertainty protocol must not be used when emissions are estimated using method 2, 3 or 4.

(2A) Subsection (2) does not apply to assessing the uncertainty of scope 1 fugitive emissions estimates for open cut coal mines using method 2, 3 or 4.

(3) Estimates need only provide for statistical uncertainties in accordance with the uncertainty protocol.

Chapter 9—Application and transitional provisions

9.10 Amendments made by the *National Greenhouse and Energy Reporting (Measurement) Amendment (Energy) Determination 2017*

The amendments made by the *National Greenhouse and Energy Reporting (Measurement) Amendment (Energy) Determination 2017* apply in relation to:

(a) the financial year starting on 1 July 2017; and

(b) later financial years.

9.11 Amendments made by the *National Greenhouse and Energy Reporting (Measurement) Amendment (2018 Update) Determination 2018*

The amendments made by the *National Greenhouse and Energy Reporting (Measurement) Amendment (2018 Update) Determination 2018* apply in relation to:

(a) the financial year starting on 1 July 2018; and

(b) later financial years.

Schedule 1—Energy content factors and emission factors

(section 2.4, subsections 2.5(1), 2.6(1), 2.20(1) and 2.21(1), paragraph 2.38(2)(b), section 2.41, subsections 2.42(1) and 2.48(2), section 3.14, subsections 4.31(1), 4.42(1) and 4.55(1), section 4.60 and subsections 4.71(2), 4.94(2), 5.19(1), 5.37(1), 5.48(1), 5.53(2), 6.3(1) and (3), 6.5(1) and (4), 7.2(1) and 7.3(1))

Note: Under the 2006 IPCC Guidelines, the emission factor for CO_2 released from combustion of biogenic carbon fuels is zero.

Part 1—Fuel combustion—solid fuels and certain coal-based products

Item	**Fuel combusted**	**Energy content factor GJ/t**	**Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)**		
			CO_2	**CH_4**	**N_2O**
1	Bituminous coal	27.0	90.0	0.03	0.2
1A	Sub-bituminous coal	21.0	90.0	0.03	0.2
1B	Anthracite	29.0	90.0	0.03	0.2
2	Brown coal	10.2	93.5	0.02	0.4
3	Coking coal	30.0	91.8	0.02	0.2
4	Coal briquettes	22.1	95.0	0.07	0.3
5	Coal coke	27.0	107.0	0.04	0.2
6	Coal tar	37.5	81.8	0.03	0.2
7	Solid fossil fuels other than those mentioned in items 1 to 5	22.1	95.0	0.07	0.3
8	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	26.3	81.6	0.02	0.2
9	Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	10.5	87.1	0.7	1.1
10	Dry wood	16.2	0.0	0.10	1.2
11	Green and air dried wood	10.4	0.0	0.10	1.2
12	Sulphite lyes	12.4	0.0	0.07	0.6
13	Bagasse	9.6	0.0	0.2	1.2
14	Biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	12.2	0.0	0.7	1.1
15	Charcoal	31.1	0.0	4.8	1.1

Item	**Fuel combusted**	**Energy content factor GJ/t**	**Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)**		
			CO_2	**CH_4**	**N_2O**
16	Primary solid biomass fuels other than those mentioned in items 10 to 15	12.2	0.0	0.7	1.1

Note: Energy content and emission factors for coal products are measured on an as combusted basis. The energy content for black coal and coking coal (metallurgical coal) is on a washed basis.

Part 2—Fuel combustion—gaseous fuels

Item	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_2O
17	Natural gas distributed in a pipeline	39.3×10^{-3}	51.4	0.1	0.03
18	Coal seam methane that is captured for combustion	37.7×10^{-3}	51.4	0.2	0.03
19	Coal mine waste gas that is captured for combustion	37.7×10^{-3}	51.9	4.1	0.03
20	Compressed natural gas that has reverted to standard conditions	39.3×10^{-3}	51.4	0.1	0.03
21	Unprocessed natural gas	39.3×10^{-3}	51.4	0.1	0.03
22	Ethane	62.9×10^{-3}	56.5	0.03	0.03
23	Coke oven gas	18.1×10^{-3}	37.0	0.03	0.05
24	Blast furnace gas	4.0×10^{-3}	234.0	0.0	0.03
25	Town gas	39.0×10^{-3}	60.2	0.0	0.03
26	Liquefied natural gas	25.3 GJ/kL	51.4	0.1	0.03
27	Gaseous fossil fuels other than those mentioned in items 17 to 26	39.3×10^{-3}	51.4	0.1	0.03
28	Landfill biogas that is captured for combustion (methane only)	37.7×10^{-3}	0.0	4.8	0.03
29	Sludge biogas that is captured for combustion (methane only)	37.7×10^{-3}	0.0	4.8	0.03
30	A biogas that is captured for combustion, other than those mentioned in items 28 and 29 (methane only)	37.7×10^{-3}	0.0	4.8	0.03

Part 3—Fuel combustion—liquid fuels and certain petroleum-based products for stationary energy purposes

Item	**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_2O**
31	Petroleum based oils (other than petroleum based oil used as fuel)	38.8	13.9	0.0	0.0
32	Petroleum based greases	38.8	3.5	0.0	0.0
33	Crude oil including crude oil condensates	45.3 GJ/t	69.6	0.1	0.2
34	Other natural gas liquids	46.5 GJ/t	61.0	0.1	0.2
35	Gasoline (other than for use as fuel in an aircraft)	34.2	67.4	0.2	0.2
36	Gasoline for use as fuel in an aircraft	33.1	67.0	0.2	0.2
37	Kerosene (other than for use as fuel in an aircraft)	37.5	68.9	0.0	0.2
38	Kerosene for use as fuel in an aircraft	36.8	69.6	0.02	0.2
39	Heating oil	37.3	69.5	0.03	0.2
40	Diesel oil	38.6	69.9	0.1	0.2
41	Fuel oil	39.7	73.6	0.04	0.2
42	Liquefied aromatic hydrocarbons	34.4	69.7	0.02	0.2
43	Solvents if mineral turpentine or white spirits	34.4	69.7	0.02	0.2
44	Liquefied petroleum gas	25.7	60.2	0.2	0.2
45	Naphtha	31.4	69.8	0.00	0.01
46	Petroleum coke	34.2 GJ/t	92.6	0.07	0.2
47	Refinery gas and liquids	42.9 GJ/t	54.7	0.02	0.0
48	Refinery coke	34.2 GJ/t	92.6	0.07	0.2
49	Petroleum based products other than: (a) petroleum based oils and petroleum based greases mentioned in items 31 and 32; and (b) the petroleum based products mentioned in items 33 to 48.	34.4	69.8	0.0	0.2
50	Biodiesel	34.6	0.0	0.07	0.2

Item	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_2O
51	Ethanol for use as a fuel in an internal combustion engine	23.4	0.0	0.07	0.2
52	Biofuels other than those mentioned in items 50 and 51	23.4	0.0	0.07	0.2

Part 4—Fuel combustion—fuels for transport energy purposes

Division 4.1—Fuel combustion—fuels for transport energy purposes

Item	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_2O
53	Gasoline (other than for use as fuel in an aircraft)	34.2	67.4	0.5	1.8
54	Diesel oil	38.6	69.9	0.1	0.5
55	Gasoline for use as fuel in an aircraft	33.1	67.0	0.05	0.7
56	Kerosene for use as fuel in an aircraft	36.8	69.6	0.01	0.6
57	Fuel oil	39.7	73.6	0.07	0.6
58	Liquefied petroleum gas	26.2	60.2	0.6	0.7
59	Biodiesel	34.6	0.0	0.7	1.9
60	Ethanol for use as fuel in an internal combustion engine	23.4	0.0	0.7	1.9
61	Biofuels other than those mentioned in items 59 and 60	23.4	0.0	0.7	1.9
62	Compressed natural gas that has reverted to standard conditions (light duty vehicles)	39.3 × 10-3 GJ/m3	51.4	6.5	0.3
63	Compressed natural gas that has reverted to standard conditions (heavy duty vehicles)	39.3 × 10-3 GJ/m3	51.4	2.5	0.3
63A	Liquefied natural gas (light duty vehicles)	25.3	51.4	6.5	0.3
63B	Liquefied natural gas (heavy duty vehicles)	25.3	51.4	2.5	0.3

Division 4.2—Fuel combustion—liquid fuels for transport energy purposes for post-2004 vehicles

Item	**Fuel combusted**	**Energy content factor** GJ/kL	**Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)**		
			CO_2	**CH_4**	**N_2O**
64	Gasoline (other than for use as fuel in an aircraft)	34.2	67.4	0.02	0.2
65	Diesel oil	38.6	69.9	0.01	0.6
66	Liquefied petroleum gas	26.2	60.2	0.4	0.3
67	Ethanol for use as fuel in an internal combustion engine	23.4	0.0	0.2	0.2

Division 4.3—Fuel combustion—liquid fuels for transport energy purposes for certain trucks

Item	Fuel type	Heavy vehicles design standard	Energy content factor GJ/kL	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
				CO_2	CH_4	N_2O
68	Diesel oil	Euro iv or higher	38.6	69.9	0.06	0.5
69	Diesel oil	Euro iii	38.6	69.9	0.1	0.5
70	Diesel oil	Euro i	38.6	69.9	0.2	0.5

Part 5—Consumption of fuels for non-energy product purposes

Item	Fuel consumed	Energy content factor (GJ/t unless otherwise indicated)	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	CH_4	N_2O
71	Solvents if mineral turpentine or white spirits	34.4 GJ/kL	Not applicable		
72	Bitumen	43.2	Not applicable		
73	Waxes	45.8	Not applicable		
74	Carbon black if used as a petrochemical feedstock	37.1	Not applicable		
75	Ethylene if used as a petrochemical feedstock	50.3	Not applicable		
76	Petrochemical feedstock other than those mentioned in items 74 and 75		Not applicable		

Part 6—Indirect (scope 2) emission factors from consumption of electricity purchased or lost from grid

Indirect (scope 2) emissions factors from consumption of electricity purchased or lost from grid

Item	Column 1 State, Territory or grid description	Column 2 Emission factor kg CO_2-e/kWh
77	New South Wales and Australian Capital Territory	0.82
78	Victoria	1.07
79	Queensland	0.80
80	South Australia	0.51
81	South West Interconnected System in Western Australia	0.70
82	Tasmania	0.19
83	Northern Territory	0.64

Part 7—Energy commodities

Item	Energy commodity	Energy content factor (GJ/t unless otherwise indicated)
84	Uranium (U_3O_8)	470 000
85	Sulphur	4.9
86	Hydrogen	143

Schedule 2—Standards and frequency for analysing energy content factor etc for solid fuels

(subsections 2.5(1), 2.6(1) and 2.8(1) and (2))

Item	Fuel combusted	Parameter	Standard	Frequency
1	Bituminous coal	Energy content factor	AS 1038.5—1998	Monthly sample composite
		Carbon	AS 1038.6.1—1997 AS 1038.6.4—2005	Monthly sample composite
		Moisture	AS 1038.1—2001 AS 1038.3—2000	Each delivery
		Ash	AS 1038.3—2000	Each delivery
1A	Sub-bituminous coal	Energy content factor	AS 1038.5—1998	Monthly sample composite
		Carbon	AS 1038.6.1—1997 AS 1038.6.4—2005	Monthly sample composite
		Moisture	AS 1038.1—2001 AS 1038.3—2000	Each delivery
		Ash	AS 1038.3—2000	Each delivery
1B	Anthracite	Energy content factor	AS 1038.5—1998	Monthly sample composite
		Energy content factor	AS 1038.5—1998	Monthly sample composite
		Carbon	AS 1038.6.1—1997 AS 1038.6.4—2005	Monthly sample composite
		Moisture	AS 1038.1—2001 AS 1038.3—2000	Each delivery
		Ash	AS 1038.3—2000	Each delivery
2	Brown coal	Energy content factor	AS 1038.5—1998	Monthly sample composite
		Carbon	AS 2434.6—2002	Monthly sample composite
		Moisture	AS 2434.1—1999	Each delivery
		Ash	AS 2434.8—2002	Each delivery
3	Coking coal	Energy content factor	AS 1038.5—1998	Monthly sample composite
		Carbon	AS 1038.6.1—1997 AS 1038.6.4—2005	Monthly sample composite
		Moisture	AS 1038.1—2001 AS 1038.3—2000	Each delivery

Item	Fuel combusted	Parameter	Standard	Frequency
		Ash	AS 1038.3—2000	Each delivery
4	Coal briquettes	Energy content factor	AS 1038.5—1998	Monthly sample composite
		Carbon	AS 2434.6—2002	Monthly sample composite
		Moisture	AS 2434.1—1999	Each delivery
		Ash	AS 2434.8—2002	Each delivery
5	Coal coke	Energy content factor	AS 1038.5—1998	Monthly sample composite
		Carbon	AS 1038.6.1—1997 AS 1038.6.4—2005	Monthly sample composite
		Moisture	AS 1038.2—2006	Each delivery
		Ash	AS 1038.3—2000	Each delivery
6	Coal tar	Energy content factor	N/A	Monthly sample composite
		Carbon	N/A	Monthly sample composite
		Moisture	N/A	Each delivery
		Ash	N/A	Each delivery
7	Solid fuels other than those mentioned in items 1 to 5	N/A	N/A	N/A
8	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery
9	Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery
10	Dry wood	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006 CEN/TS 14774-3:2004	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery

Item	Fuel combusted	Parameter	Standard	Frequency
11	Green and air dried wood	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006 CEN/TS 14774-3:2004	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery
12	Sulphite lyes	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006 CEN/TS 14774-3:2004	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery
13	Bagasse	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006 CEN/TS 14774-3:2004	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery
14	Biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery
15	Charcoal	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery
16	Primary solid biomass fuels other than those items mentioned in items 10 to 15	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
		Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006 CEN/TS 14774-3:2004	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery

Schedule 3—Carbon content factors

(subsection 2.61(1), sections 3.65, 4.66 and subsections 4.67(2) and 4.68(2))

Note 1: Under the 2006 IPCC Guidelines, the emission factor for CO_2 released from combustion of biogenic carbon fuels is zero.

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

Part 1—Solid fuels and certain coal-based products

Item	**Fuel type**	**Carbon content factor tC/t fuel**
Solid fossil fuels		
1	Bituminous coal	0.663
1A	Sub-bituminous coal	0.515
1B	Anthracite	0.712
2	Brown coal	0.260
3	Coking coal	0.752
4	Coal briquettes	0.574
5	Coal coke	0.789
6	Coal tar	0.837
7	Solid fossil fuels other than those mentioned in items 1 to 5	0.574
Fuels derived from recycled materials		
8	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	0.585
9	Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	0.250
Primary solid biomass fuels		
10	Dry wood	0
11	Green and air dried wood	0
12	Sulphite lyes	0
13	Bagasse	0
14	Biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	0
15	Charcoal	0
16	Primary solid biomass fuels other than those mentioned in items 10 to 15	0

Part 2—Gaseous fuels

Item	**Fuel type**	**Carbon content factor (tC/m^3 of fuel unless otherwise specified)**
Gaseous fossil fuels		
17	Natural gas if distributed in a pipeline	5.52×10^{-4}
17A	Natural gas, if: (a) distributed in a pipeline; and (b) measured in units of gigajoules only	1.40×10^{-2} tC/GJ of fuel
18	Coal seam methane that is captured for combustion	5.52×10^{-4}
19	Coal mine waste gas that is captured for combustion	5.34×10^{-4}
20	Compressed natural gas	5.52×10^{-4}
21	Unprocessed natural gas	5.52×10^{-4}
22	Ethane	9.70×10^{-4}
23	Coke oven gas	1.83×10^{-4}
24	Blast furnace gas	2.55×10^{-4}
25	Town gas	6.41×10^{-4}
26	Liquefied natural gas	0.355 tC/kL of fuel
27	Gaseous fossil fuels other than those mentioned in items 17 to 26	5.52×10^{-4}
Biogas captured for combustion		
28	Landfill biogas (methane) that is captured for combustion	0
29	Sludge biogas (methane) that is captured for combustion	0
30	A biogas (methane) that is captured for combustion, other than those mentioned in items 28 and 29	0

Part 3—Liquid fuels and certain petroleum-based products

Item	Fuel type	Carbon content factor (tC/kL of fuel unless otherwise specified)
Petroleum based oils and petroleum based greases		
31	Petroleum based oils (other than petroleum based oils used as fuel)	0.737
32	Petroleum based greases	0.737
Petroleum based products other than petroleum based oils and petroleum based greases		
33	Crude oil including crude oil condensates	0.861 tC/t fuel
34	Other natural gas liquids	0.774 tC/t fuel
35	Gasoline (other than for use as fuel in an aircraft)	0.629
36	Gasoline for use as fuel in an aircraft	0.605
37	Kerosene (other than for use as fuel in an aircraft)	0.705
38	Kerosene for use as fuel in an aircraft	0.699
39	Heating oil	0.708
40	Diesel oil	0.736
41	Fuel oil	0.797
42	Liquefied aromatic hydrocarbons	0.654
43	Solvents if mineral turpentine or white spirits	0.654
44	Liquefied petroleum gas	0.422
45	Naphtha	0.598
46	Petroleum coke	0.856 tC/t fuel
47	Refinery gas and liquids	0.641 tC/t fuel
48	Refinery coke	0.864 tC/t fuel
49	Bitumen	0.951 tC/t fuel
50	Waxes	0.871 tC/t fuel
51	Petroleum based products other than: (a) petroleum based oils and petroleum based greases mentioned in items 31 and 32; and (b) the petroleum based products mentioned in items 33 to 50	0.655
Biofuels		
52	Biodiesel	0
53	Ethanol for use as a fuel in an internal combustion engine	0
54	Biofuels other than those mentioned in items 52 and 53	0

Part 4—Petrochemical feedstocks and products

Item	Fuel type	Carbon content factor (tC/t fuel unless otherwise specified)
Petrochemical feedstocks		
55	Carbon black if used as a petrochemical feedstock	1
56	Ethylene if used as a petrochemical feedstock	0.856
57	Petrochemical feedstock other than those mentioned in items 55 and 56	0.856
Petrochemical products		
58	Propylene	0.856
59	Polyethylene	0.856
60	Polypropylene	0.856
61	Butadiene	0.888
62	Styrene	0.923

Part 5—Carbonates

Item	Carbonate type	Carbon content factor (tC/t pure carbonate material unless otherwise specified)
63	Calcium carbonate	0.120
64	Magnesium carbonate	0.142
65	Sodium carbonate	0.113
66	Sodium bicarbonate	0.143

Endnotes

Endnote 1—About the endnotes

The endnotes provide information about this compilation and the compiled law.

The following endnotes are included in every compilation:

Endnote 1—About the endnotes
Endnote 2—Abbreviation key
Endnote 3—Legislation history
Endnote 4—Amendment history

Abbreviation key—Endnote 2
The abbreviation key sets out abbreviations that may be used in the endnotes.

Legislation history and amendment history—Endnotes 3 and 4
Amending laws are annotated in the legislation history and amendment history.

The legislation history in endnote 3 provides information about each law that has amended (or will amend) the compiled law. The information includes commencement details for amending laws and details of any application, saving or transitional provisions that are not included in this compilation.

The amendment history in endnote 4 provides information about amendments at the provision (generally section or equivalent) level. It also includes information about any provision of the compiled law that has been repealed in accordance with a provision of the law.

Editorial changes
The *Legislation Act 2003* authorises First Parliamentary Counsel to make editorial and presentational changes to a compiled law in preparing a compilation of the law for registration. The changes must not change the effect of the law. Editorial changes take effect from the compilation registration date.

If the compilation includes editorial changes, the endnotes include a brief outline of the changes in general terms. Full details of any changes can be obtained from the Office of Parliamentary Counsel.

Misdescribed amendments
A misdescribed amendment is an amendment that does not accurately describe the amendment to be made. If, despite the misdescription, the amendment can be given effect as intended, the amendment is incorporated into the compiled law and the abbreviation “(md)” added to the details of the amendment included in the amendment history.

If a misdescribed amendment cannot be given effect as intended, the abbreviation “(md not incorp)” is added to the details of the amendment included in the amendment history.

Endnote 2—Abbreviation key

ad = added or inserted
am = amended
amdt = amendment
c = clause(s)
C[x] = Compilation No. x
Ch = Chapter(s)
def = definition(s)
Dict = Dictionary
disallowed = disallowed by Parliament
Div = Division(s)
ed = editorial change
exp = expires/expired or ceases/ceased to have effect
F = Federal Register of Legislation
gaz = gazette
LA = *Legislation Act 2003*
LIA = *Legislative Instruments Act 2003*
(md) = misdescribed amendment can be given effect
(md not incorp) = misdescribed amendment cannot be given effect
mod = modified/modification
No. = Number(s)
o = order(s)
Ord = Ordinance
orig = original
par = paragraph(s)/subparagraph(s) /sub-subparagraph(s)
pres = present
prev = previous
(prev…) = previously
Pt = Part(s)
r = regulation(s)/rule(s)
reloc = relocated
renum = renumbered
rep = repealed
rs = repealed and substituted
s = section(s)/subsection(s)
Sch = Schedule(s)
Sdiv = Subdivision(s)
SLI = Select Legislative Instrument
SR = Statutory Rules
Sub-Ch = Sub-Chapter(s)
SubPt = Subpart(s)
underlining = whole or part not commenced or to be commenced

Endnote 3—Legislation history

Name	**Registration**	**Commencement**	**Application, saving and transitional provisions**
National Greenhouse and Energy Reporting (Measurement) Determination 2008	27 June 2008 (F2008L02309)	1 July 2008	
National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2009 (No. 1)	26 June 2009 (F2009L02571)	27 June 2009	s 4
National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2010 (No. 1)	29 June 2010 (F2010L01855)	30 June 2010	s 4
National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2011 (No. 1)	29 June 2011 (F2011L01315)	s 1–4 and Sch 1: 1 July 2011 Sch 2: 1 July 2012	s 4
National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2012 (No. 1)	29 June 2012 (F2012L01439)	1 July 2012	—
National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2013 (No. 1)	27 June 2013 (F2013L01191)	1 July 2013	—
National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2014 (No. 1)	26 June 2014 (F2014L00828)	s 1–4: 27 June 2014 (s 2 item 1) Sch 1: 1 July 2014 (s 2 item 2) Sch 2: 1 July 2015 (s 2 item 3)	—
National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2015 (No. 1)	27 Apr 2015 (F2015L00598)	1 July 2015 (s 2)	—
National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2015 (No. 2)	30 June 2015 (F2015L01017)	Sch 1 and Sch 3 (item 1): 1 July 2015 (s 2(1) items 2, 4) Sch 2 and Sch 3 (item 2); 1 July 2016 (s 2(1) items 3, 5)	—
National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2016 (No. 1)	17 May 2016 (F2016L00809)	1 July 2016 (s 2(1) item 1)	—
National Greenhouse and Energy Reporting (Measurement) Amendment (Energy) Determination 2017	30 June 2017 (F2017L00829)	1 July 2017 (s 2(1) item 1)	—

Endnote 3—Legislation history

Name	**Registration**	**Commencement**	**Application, saving and transitional provisions**
National Greenhouse and Energy Reporting (Measurement) Amendment (2018 Update) Determination 2018	28 June 2018 (F2018L00923)	1 July 2018 (s 2(1) item 1)	—

Endnote 4—Amendment history

Provision affected	How affected
Chapter 1	
Part 1.1	
s 1.2	rep LA s 48D
Division 1.1.1	
s 1.3	am 2009 No. 1; 2012 No. 1; 2013 No. 1; 2015 No 2; 2016 No 1; F2018L00923
s 1.4	am 2012 No. 1; 2013 No. 1; 2015 No 1
Division 1.1.2	
s 1.8	am 2009 No. 1; 2010 No. 1; 2011 No. 1; 2012 No. 1; 2013 No. 1; 2014 No. 1; 2015 No 2; 2016 No 1; F2018L00923
s 1.9	am 2009 No. 1; 2010 No. 1; 2012 No. 1; 2014 No. 1
s 1.9A	ad 2013 No. 1
s 1.9B	ad 2013 No. 1
s 1.10	rs 2009 No. 1
	am 2011 No. 1; 2012 No. 1; 2015 No 2
Part 1.1A	ad 2012 No. 1
	rep 2015 No 1
s 1.10A	ad 2012 No. 1
	rep 2015 No 1
s 1.10B	ad 2012 No. 1
	rep 2015 No 1
s 1.10C	ad 2012 No. 1
	rep 2015 No 1
s 1.10D	ad 2012 No. 1
	rep 2015 No 1
s 1.10E	ad 2012 No. 1
	rep 2015 No 1
s 1.10F	ad 2012 No. 1
	rep 2015 No 1
Division 1.1A.3	ad 2013 No. 1
	rep 2015 No 1
s 1.10G	ad 2013 No. 1
	rep 2015 No 1
Division 1.1A.4	ad 2013 No. 1
	rep 2015 No 1
s 1.10H	ad 2013 No. 1
	rep 2015 No 1
Part 1.1B	

Endnote 4—Amendment history

Provision affected	How affected
Part 1.1B	ad 2013 No. 1
	rep 2015 No 1
s 1.10J	ad 2013 No. 1
	rep 2015 No 1
s 1.10JA	ad 2013 No. 1
	rep 2015 No 1
s 1.10JB	ad 2013 No. 1
	rep 2015 No 1
s 1.10JC	ad 2013 No. 1
	rep 2015 No 1
s 1.10JD	ad 2013 No. 1
	rep 2015 No 1
s 1.10JE	ad 2013 No. 1
	rep 2015 No 1
s 1.10JF	ad 2013 No. 1
	rep 2015 No 1
s 1.10JG	ad 2013 No. 1
	rep 2015 No 1
s 1.10JH	ad 2013 No. 1
	rep 2015 No 1
s 1.10JI	ad 2013 No. 1
	rep 2015 No 1
s 1.10JJ	ad 2013 No. 1
	rep 2015 No 1
s 1.10JK	ad 2013 No. 1
	am 2014 No. 1
	rep 2015 No 1
s 1.10JL	ad 2013 No. 1
	rep 2015 No 1
s 1.10JM	ad 2013 No. 1
	rep 2015 No 1
s 1.10JN	ad 2013 No. 1
	rep 2015 No 1
s 1.10JO	ad 2013 No. 1
	rep 2015 No 1
s 1.10JP	ad 2013 No. 1
	rep 2015 No 1
s 1.10JQ	ad 2013 No. 1
	rep 2015 No 1
Part 1.1C	ad 2013 No. 1

Provision affected	How affected
	rep 2015 No 1
s 1.10K	ad 2013 No. 1
	rep 2015 No 1
s 1.10KA	ad 2013 No. 1
	rep 2015 No 1
s 1.10KB	ad 2013 No. 1
	rep 2015 No 1
s 1.10KC	ad 2013 No. 1
	rep 2015 No 1
s 1.10KD	ad 2013 No. 1
	rep 2015 No 1
s 1.10KE	ad 2013 No. 1
	rep 2015 No 1
s 1.10KF	ad 2013 No. 1
	rep 2015 No 1
s 1.10KG	ad 2013 No. 1
	rep 2015 No 1
s 1.10KH	ad 2013 No. 1
	rep 2015 No 1
s 1.10KI	ad 2013 No. 1
	rep 2015 No 1
s 1.10KJ	ad 2013 No. 1
	rep 2015 No 1
s 1.19KK	ad 2013 No. 1
	rep 2015 No 1
s 1.10KL	ad 2013 No. 1
	rep 2015 No 1
s 1.10KM	ad 2013 No. 1
	rep 2015 No 1
	rep 2015 No 1
s 1.10KN	ad 2013 No. 1
	rep 2015 No 1
Part 1.2	
s 1.11	am 2016 No 1; F2018L00923
Division 1.2.1	
s 1.12	rs F2018L00923
s 1.13	am 2011 No. 1; No. 2013 No. 1
	rs F2018L00923
Division 1.2.2	
s 1.18	am 2012 No. 1; 2013 No. 1; F2018L00923

Endnote 4—Amendment history

Provision affected	How affected
s 1.18A	ad 2012 No. 1
s 1.19	am 2012 No. 1; 2013 No. 1; 2014 No. 1; 2016 No 1; F2018L00923
Division 1.2.3	
Division 1.2.3	ad 2010 No. 1
s 1.19A	ad 2010 No. 1
	am 2016 No 1
s 1.19B	ad 2010 No. 1
	am 2016 No 1
s 1.19C	ad 2010 No. 1
	am 2016 No 1
s 1.19D	ad 2010 No. 1
	am 2016 No 1
s 1.19E	ad 2010 No. 1
	am 2016 No 1
s 1.19F	ad 2010 No. 1
	am 2016 No 1
s 1.19G	ad 2010 No. 1
	am 2014 No. 1; 2016 No 1
s 1.19GA	ad 2016 No 1
s 1.19H	ad 2010 No. 1
	am 2012 No. 1; 2016 No 1
s 1.19I	ad 2010 No. 1
	am 2016 No 1
	ed C7
s 1.19J	ad 2010 No. 1
	am 2012 No. 1
s 1.19K	ad 2010 No. 1
	am 2012 No 1
	ed C7
s 1.19L	ad 2010 No. 1
s 1.19M	ad 2010 No. 1
	ed C7
s 1.19N	ad 2010 No. 1
	rep 2016 No 1
Part 1.3	
Division 1.3.2	
Subdivision 1.3.2.1	
s 1.21	am 2011 No. 1
s 1.21A	ad 2013 No. 1
Division 1.3.3	

Provision affected	How affected
Subdivision 1.3.3.1	
s 1.27	am 2011 No. 1
s 1.27A	ad 2013 No. 1
s 1.28	am 2009 No. 1
Chapter 2	
Chapter 2 heading	rs 2009 No. 1
Part 2.1	
s 2.1	rs 2009 No. 1
Part 2.2	
Division 2.2.1	
s 2.2	am 2009 No. 1
	rs 2013 No. 1
s 2.3	am 2009 No. 1; 2011 No. 1; 2012 No. 1
Division 2.2.2	
s 2.4	am 2009 No. 1
Division 2.2.3	
Subdivision 2.2.3.1	
s 2.5	am 2009 No. 1; 2010 No. 1; 2015 No 1
Subdivision 2.2.3.2	
s 2.6	am 2009 No. 1; 2010 No. 1
Subdivision 2.2.3.3	
s 2.7	am 2009 No. 1
s 2.8	am 2009 No. 1
s 2.9	am 2009 No. 1
s 2.10	am 2011 No. 1
s 2.11	am 2009 No. 1
	rs 2011 No. 1
Division 2.2.4	
s 2.12	am 2011 No. 1; 2013 No. 1; 2014 No. 1
Division 2.2.5	
s 2.14	am 2009 No. 1
s 2.15	am 2011 No. 1; 2013 No. 1
s 2.16	am 2011 No. 1
s 2.17	am 2009 No. 1
Part 2.3	
Division 2.3.1	
s 2.18	am 2009 No. 1
	rs 2013 No. 1
s 2.19	am 2009 No. 1; 2011 No. 1; 2012 No. 1
Division 2.3.2	

Endnote 4—Amendment history

Provision affected	How affected
s 2.20	am 2009 No. 1; 2010 No. 1
Division 2.3.3	
Subdivision 2.3.3.1	
s 2.21	am 2009 No. 1; 2010 No. 1
s 2.22	am 2009 No. 1; 2010 No. 1; 2012 No. 1; 2015 No 1
Subdivision 2.3.3.2	
s 2.24	am 2012 No. 1
s 2.25	am 2010 No. 1; 2013 No. 1; F2018L00923
Division 2.3.6	
s 2.29	am 2009 No. 1
s 2.30	am 2011 No. 1; 2013 No. 1
s 2.31	am 2011 No. 1; 2012 No. 1; 2013 No. 1; 2014 No. 1
s 2.32	am 2009 No. 1; 2010 No. 1; 2012 No. 1; 2014 No. 1
s 2.33	rs 2012 No. 1
s 2.34	am 2012 No. 1
s 2.35	am 2010 No. 1; 2012 No. 1
s 2.36	rs 2012 No. 1
s 2.37	rs 2012 No. 1
s 2.38	am 2009 No. 1; 2011 No. 1; 2014 No. 1
Part 2.4	
Division 2.4.1	
s 2.39	am 2009 No. 1
	rs 2013 No. 1
s 2.39A	ad 2009 No. 1
Subdivision 2.4.1.1	
Subdivision 2.4.1.1 heading	ad 2009 No. 1
s 2.40	am 2009 No. 1
Subdivision 2.4.1.2	
Subdivision 2.4.1.2	ad 2009 No. 1
s 2.40A	ad 2009 No. 1
Division 2.4.2	
Division 2.4.2 heading	rs 2009 No. 1
s 2.41	am 2009 No. 1; 2010 No. 1
Division 2.4.3	
Division 2.4.3 heading	rs 2009 No. 1
Subdivision 2.4.3.1	
Subdivision 2.4.3.1 heading	rs 2009 No. 1
s 2.42	am 2009 No. 1; 2010 No. 1
s 2.43	am 2009 No. 1; 2010 No. 1; 2015 No 1
Subdivision 2.4.3.2	

Provision affected	How affected
s 2.45	am 2010 No. 1
Division 2.4.4	
Division 2.4.4 heading	rs 2009 No. 1
Division 2.4.5	
Division 2.4.5	rs 2009 No. 1
s 2.48	am 2012 No. 1
Division 2.4.5A	
Division 2.4.5A	ad 2009 No. 1
s 2.48A	ad 2009 No. 1
	am 2011 No. 1
s 2.48B	ad 2009 No. 1
s 2.48C	ad 2009 No. 1
Division 2.4.6	
s 2.50	am 2009 No. 1
s 2.51	am 2010 No. 1; 2013 No. 1
s 2.52	am 2010 No. 1; 2013 No. 1
s 2.53	am 2009 No. 1; 2010 No. 1
Part 2.5	
s 2.54	rs 2009 No. 1
Division 2.5.1	
s 2.55	am 2009 No. 1
Division 2.5.2	
Division 2.5.2 heading	rs 2011 No. 1
s 2.57	am 2009 No. 1; 2011 No. 1
s 2.58	am 2009 No. 1; 2011 No. 1
Division 2.5.3	
s 2.59	am 2009 No. 1
s 2.60	am 2009 No. 1
s 2.62	am 2010 No. 1
s 2.63	am 2010 No. 1
Part 2.6	
s 2.66	am 2009 No. 1; 2011 No. 1
s 2.67	am 2009 No. 1; 2011 No. 1
Part 2.7	
s 2.68	rs 2012 No. 1
	am 2013 No. 1; F2018L00923
s 2.71	am 2013 No. 1; F2018L00923
Chapter 3	
Chapter 3 heading	rs 2009 No. 1; 2010 No. 1
Part 3.1	

Endnote 4—Amendment history

Provision affected	How affected
s 3.1	rs 2009 No. 1; 2010 No. 1
Part 3.2	
Part 3.2 heading	rs 2009 No. 1
Division 3.2.1	
s 3.2	rs 2009 No. 1
Division 3.2.2	
Subdivision 3.2.2.1	
s 3.3	am 2009 No. 1
s 3.4	am 2009 No. 1; 2013 No. 1
s 3.5	am 2015 No 1
Subdivision 3.2.2.2	
s 3.6	am 2011 No. 1; 2014 No 1; 2015 No 2
s 3.13	am 2015 No 2
Subdivision 3.2.2.3	
s 3.14	am 2009 No. 1; 2015 No 1
s 3.15	rs 2011 No. 1; 2013 No. 1
	am 2015 No 1
s 3.15A	ad 2013 No. 1
	am 2015 No 1
s 3.16	rs 2011 No. 1
	am 2013 No. 1
s 3.17	am 2015 No 1
Division 3.2.3	
Subdivision 3.2.3.1	
s 3.18	am 2009 No. 1
s 3.19	am 2009 No. 1
Subdivision 3.2.3.2	
s 3.20	am 2013 No. 1; 2015 No 1
s 3.21	am 2012 No. 1; 2015 No 1
s 3.22	am 2010 No. 1; 2012 No. 1
s 3.23	am 2012 No. 1
s 3.24	am 2012 No. 1
s 3.25	am 2012 No. 1
s 3.25A	ad 2012 No. 1
s 3.25B	ad 2012 No. 1
s 3.25C	ad 2012 No. 1
s 3.25D	ad 2012 No. 1
Division 3.2.4	
Subdivision 3.2.4.1	
s 3.30	am 2009 No. 1

Provision affected	How affected
	rs F2018L00923
s 3.31	am 2009 No. 1; F2018L00923
Subdivision 3.2.4.2	
s 3.32	am 2010 No. 1; F2018L00923
s 3.33	am F2018L00923
s 3.34	rs 2010 No. 1
	am F2018L00923
Part 3.3	
Division 3.3.1	
s 3.40A	ad 2009 No. 1
	am 2014 No. 1; 2016 No 1
s 3.41	rs 2009 No. 1
Division 3.3.2	
Division 3.3.2 heading	rs 2009 No. 1
Subdivision 3.3.2.1	
Subdivision 3.3.2.1	ad 2010 No. 1
s 3.42	rs 2009 No. 1
	am 2010 No. 1; 2013 No. 1
Subdivision 3.3.2.2	
Subdivision 3.3.2.2 heading	ad 2010 No. 1
s 3.43	am 2009 No. 1; 2011 No. 1; 2015 No 2
s 3.44	am 2009 No. 1; 2015 No 1
s 3.45	am 2009 No. 1
	rs 2011 No. 1
	am 2015 No 1; 2015 No 2
s 3.45A	ad 2015 No 2
s 3.46	am 2009 No. 1
	rs 2011 No. 1
Subdivision 3.3.2.3	
Subdivision 3.3.2.3	ad 2010 No. 1
s 3.46A	ad 2010 No. 1
	rs 2012 No. 1
	am 2013 No. 1; 2014 No. 1
s 3.46B	ad 2013 No. 1
	am 2015 No 1
Division 3.3.3	
Subdivision 3.3.3.1	
s 3.47	rs 2009 No. 1
Subdivision 3.3.3.2	
Subdivision 3.3.3.2 heading	rs 2010 No. 1

Endnote 4—Amendment history

Provision affected	How affected
s 3.48	am 2009 No. 1; 2010 No. 1
s 3.49	am 2010 No. 1; 2012 No. 1; 2015 No 1
s 3.50	am 2010 No. 1; 2012 No. 1
Subdivision 3.3.3.3	
s 3.51	am 2009 No. 1; 2011 No. 1; 2015 No 2
s 3.52	am 2015 No 1
s 3.53	rs 2011 No. 1
	am 2015 No 1
s 3.53A	ad 2015 No 2
s 3.54	rs 2011 No. 1
s 3.55	am 2011 No 1
	rep 2015 No 2
s 3.56	am 2010 No. 1
	rep 2011 No. 1
Subdivision 3.3.3.4	
Subdivision 3.3.3.4	ad 2010 No. 1
s 3.56A	ad 2010 No. 1
	rs 2012 No. 1
Division 3.3.4	
s 3.57	rs 2009 No. 1
s 3.58	am 2009 No. 1
s 359	am 2015 No 2
Division 3.3.5	
s 3.61	rs 2009 No. 1
s 3.62	am 2009 No. 1; 2011 No. 1; 2015 No 2
s 3.63	am 2015 No 1
Subdivision 3.3.5.2	
s 3.65	am 2009 No. 1
Subdivision 3.3.5.3	
s 3.67	am 2011 No. 1
s 3.68	rs 2011 No. 1
	am 2015 No 1
s 3.68A	ad 2015 No 2
s 3.69	am 2011 No 1
Division 3.3.6	
Division 3.3.6 heading	rs 2009 No. 1
s 3.70	rs 2009 No. 1
s 3.71	am 2009 No. 1
s 3.72	am 2010 No. 1; 2012 No. 1; 2015 No 1
s 3.73	am 2010 No. 1; 2012 No. 1

Provision affected	How affected
Division 3.3.7	
s 3.74	rs 2009 No. 1
s 3.75	am 2009 No. 1
s 3,76	am 2015 No 1
s 3.77	am 2012 No. 1
Division 3.3.8	
s 3.78	rs 2009 No. 1
s 3.79	am 2009 No. 1
s 3.80	am 2011 No. 1; 2015 No 1
s 3.81	am 2009 No. 1
Division 3.3.9	
Division 3.3.9 heading	rs 2009 No. 1
s 3.82	rs 2009 No. 1
s 3.83	am 2009 No. 1; 2010 No. 1; 2011 No. 1; 2015 No 2
Subdivision 3.3.9.1	
s 3.84	rs 2010 No. 1
	am 2012 No. 1
Subdivision 3.3.9.2	
s 3.86	rs 2011 No. 1
	am 2015 No 1; 2015 No 2
s 3.86A	ad 2015 No 2
s 3.87	am 2011 No. 1
Part 3.4	
Part 3.4	ad 2010 No. 1
Division 3.4.1	
s 3.88	ad 2010 No. 1
Division 3.4.2	
Division 3.4.2 heading	rs 2016 No 1
Subdivision 3.4.2.1	
s 3.89	ad 2010 No. 1
	am 2016 No 1
s 3.90	ad 2010 No. 1
	am 2016 No 1
Subdivision 3.4.2.2	
Subdivision 3.4.2.2 heading (first occurring)	rs 2016 No 1
s 3.91	ad 2010 No. 1
	rs 2016 No 1
	am F2018L00923
Subdivision 3.4.2.3	

Endnote 4—Amendment history

Provision affected	How affected
Subdivision 3.4.2.2 heading (second occurring)	rep 2016 No 1
Subdivision 3.4.2.3 heading	ad 2016 No 1
s 3.92	ad 2010 No. 1
	rs 2016 No 1
	am F2018L00923
Division 3.4.3	
Division 3.4.3	ad 2016 No 1
Subdivision 3.4.3.1	
s 3.93	ad 2016 No 1
s 3.94	ad 2016 No 1
Subdivision 3.4.3.2	
s 3.95	ad 2016 No 1
Subdivision 3.4.3.3	
s 3.96	ad 2016 No 1
s 3.97	ad 2016 No 1
Division 3.4.4	
Division 3.4.4	ad 2016 No 1
Subdivision 3.4.4.1	
s 3.98	ad 2016 No 1
s 3.99	ad 2016 No 1
Subdivision 3.4.4.2	
s 3.100	ad 2016 No 1
Chapter 4	
Chapter 4 heading	rs 2009 No. 1
Part 4.1	
s 4.1	am 2009 No. 1; 2011 No. 1; 2012 No. 1
Part 4.2	
Division 4.2.1	
s 4.2	am 2009 No. 1
s 4.3	am 2009 No. 1
s 4.5	am 2009 No. 1
	rs 2010 No. 1
s 4.7	am 2010 No. 1
s 4.8	am 2010 No. 1
s 4.10	am 2010 No. 1
Division 4.2.2	
s 4.11	am 2009 No. 1
s 4.12	am 2009 No. 1
s 4.13	rs 2011 No. 1

Provision affected	How affected
s 4.14	am 2010 No. 1
	rs 2011 No. 1
s 4.15	am 2011 No. 1
s 4.16	am 2010 No. 1
s 4.17	am 2010 No. 1
Division 4.2.3	
Division 4.2.3 heading	rs 2009 No. 1
s 4.20	rs 2009 No. 1; 2010 No. 1
	am 2011 No. 1; 2012 No. 1
s 4.21	am 2009 No. 1; 2012 No. 1
s 4.22	am 2009 No. 1 (Sch 1 item 92 md not incorp); 2010 No. 1
s 4.22A	ad 2012 No. 1
s 4.23	am 2009 No. 1; 2010 No. 1
s 4.23A	ad 2012 No. 1
s 4.23B	ad 2012 No. 1
s 4.23C	ad 2012 No. 1
s 4.25	am 2010 No. 1
Division 4.2.4	
s 4.26	am 2009 No. 1
	rs 2010 No. 1
Subdivision 4.2.4.1	
s 4.28	am 2009 No. 1; 2010 No. 1
Subdivision 4.2.4.2	
s 4.30	am 2009 No. 1; 2010 No. 1
s 4.31	am 2009 No. 1
	rs 2010 No. 1
	am 2011 No. 1; 2012 No. 1
s 4.32	rs 2010 No. 1
	am 2011 No. 1; 2012 No. 1
s 4.33	rs 2010 No. 1
	am 2011 No. 1
Division 4.2.5	
s 4.34	am 2012 No. 1
s 4.35	am 2009 No. 1
s 4.38	am 2009 No. 1
Part 4.3	
Division 4.3.1	
s 4.40	am 2009 No. 1
s 4.41	am 2009 No. 1
s 4.42	am 2009 No. 1; 2014 No. 1

Endnote 4—Amendment history

Provision affected	How affected
s 4.43	rs 2010 No. 1
	am 2012 No. 1; 2014 No. 1
s 4.44	rs 2010 No. 1
Division 4.3.2	
s 4.45	am 2009 No. 1
s 4.46	am 2009 No. 1
s 4.47	am 2015 No 1
Division 4.3.3	
s 4.49	am 2009 No. 1
s 4.50	am 2009 No. 1
Division 4.3.4	
s 4.51	am 2009 No. 1
s 4.52	am 2009 No. 1
Division 4.3.5	
Division 4.3.5 heading	rs 2009 No. 1; 2011 No. 1
s 4.53	rs 2009 No. 1; 2011 No. 1
s 4.54	am 2009 No. 1
s 4.55	am 2009 No. 1
	rs 2011 No. 1
	am 2012 No. 1
s 4.56	am 2009 No. 1
	rs 2011 No. 1
s 4.57	am 2009 No. 1
	rs 2011 No. 1
Division 4.3.6	
Division 4.3.6	rep 2009 No. 1
	ad 2012 No. 1
s 4.58	rep 2009 No. 1
	ad 2012 No. 1
s 4.59	rep 2009 No. 1
	ad 2012 No. 1
s 4.60	rep 2009 No. 1
s 4.61	rep 2009 No. 1
s 4.62	rep 2009 No. 1
Part 4.4	
Division 4.4.1	
Division 4.4.1 heading	rs 2009 No. 1
s 4.63	rs 2009 No. 1; 2011 No. 1
s 4.64	am 2009 No. 1
s 4.65	am 2009 No. 1

Provision affected	How affected
s 4.66	am 2009 No. 1; 2011 No. 1; 2012 No. 1; 2016 No 1; F2018L00923
s 4.67	am 2009 No. 1; 2010 No. 1; 2011 No. 1
s 4.68	am 2009 No. 1; 2010 No. 1
Division 4.4.2	
Heading to Div. 4.4.2 of Part 4.4	rs 2009 No. 1
s 4.69	am 2009 No. 1
	rs 2010 No. 1
s 4.70	am 2009 No. 1; 2010 No. 1
s 4.71	am 2009 No. 1
	rs 2011 No. 1
	ed C7
s 4.72	rs 2011 No. 1
s 4.73	rs 2011 No. 1
Division 4.4.3	
Division 4.4.3 heading	rs 2009 No. 1
s 4.74	am 2009 No. 1
Subdivision 4.4.3.1	
Subdivision 4.4.3.1 heading	rs 2010 No. 1
s 4.75	am 2009 No. 1; 2010 No. 1
s 4.76	am 2009 No. 1; 2010 No. 1
s 4.77	am 2009 No. 1; 2010 No. 1
s 4.78	am 2010 No. 1
Subdivision 4.4.3.2	
s 4.79	am 2009 No. 1
s 4.80	am 2009 No. 1
Division 4.4.4	
Division 4.4.4 heading	rs 2009 No. 1
s 4.83	am 2009 No. 1
Subdivision 4.4.4.1	
s 4.84	am 2009 No. 1
s 4.85	am 2015 No 1
Subdivision 4.4.4.2	
s 4.88	am 2009 No. 1
s 4.89	am 2015 No 1
Division 4.4.5	
Division 4.4.5 heading	rs 2009 No. 1
s 4.92	rs 2009 No. 1; 2010 No. 1
s 4.93	am 2009 No. 1
s 4.94	am 2009 No. 1

Endnote 4—Amendment history

Provision affected	How affected
	rs 2011 No. 1
	ed C7
s 4.95	rs 2011 No. 1
s 4.96	rs 2011 No. 1
Part 4.5	
s 4.97	am 2009 No. 1
s 4.98	am 2009 No. 1
s 4.99	am 2013 No. 1
s 4.100	am 2012 No. 1; 2014 No. 1; 2016 No 1
s 4.102	am 2009 No. 1; 2012 No. 1
s 4.103	ad 2009 No. 1
s 4.104	ad 2009 No. 1
Chapter 5	
Chapter 5 heading	rs 2009 No. 1
Part 5.1	
s 5.1	rs 2009 No. 1
Part 5.2	
Division 5.2	
s 5.2	rs 2009 No. 1
	am 2012 No. 1
	rs 2015 No 2
s 5.3	am 2009 No. 1; 2013 No. 1; 2015 No 2; 2016 No 1
	ed C7
Division 5.2.2	
s 5.4	am 2009 No. 1; 2011 No. 1; 2012 No. 1; 2014 No. 1; 2015 No 1
s 5.4A	ad 2012 No. 1
s 5.4B	ad 2012 No. 1
	am 2015 No 1
s 5.4C	ad 2012 No. 1
s 5.4D	ad 2012 No. 1
	am 2015 No 1
s 5.5	am 2009 No. 1
s 5.8	am 2014 No. 1
s 5.9	am 2009 No. 1; 2012 No. 1
	rs 2013 No. 1
	am 2014 No. 1
s 5.10	am 2009 No. 1; 2012 No. 1; 2013 No. 1; 2014 No. 1
s 5.10A	ad 2013 No. 1
	am 2014 No. 1
s 5.11	am 2009 No. 1; 2013 No. 1; 2014 No. 1; 2016 No 1

Provision affected	How affected
s 5.11A	ad 2009 No. 1
	am 2014 No. 1
s 5.12	am 2012 No. 1; 2013 No. 1
s 5.13	am 2009 No. 1; 2012 No. 1; 2014 No. 1; 2015 No 1
s 5.14	rs 2012 No. 1
	am 2013 No. 1
s 5.14A	ad 2011 No. 1
	am 2012 No. 1; 2013 No. 1
s 5.14B	ad 2012 No. 1
s 5.14C	ad 2012 No. 1
s 5.14D	ad 2012 No. 1
Division 5.2.3	
Subdivision 5.2.3.1	
s 5.15	am 2009 No. 1
	rs 2012 No. 1
	am 2013 No. 1; 2015 No 1
s 5.15A	ad 2012 No. 1
	am 2013 No. 1; 2015 No 1
s 5.15B	ad 2012 No. 1
	am 2013 No. 1
s 5.15C	ad 2013 No. 1
Subdivision 5.2.3.2	
Subdivision 5.2.3.2	rs 2009 No. 1
s 5.16	rs 2009 No. 1
	am 2012 No. 1
s 5.17	rs 2009 No. 1; 2012 No. 1
s 5.17AA	ad 2012 No. 1
	am 2015 No 1; 2016 No 1
s 5.17A	ad 2009 No. 1
	rs 2012 No. 1
	am 2013 No. 1
s 5.17B	ad 2009 No. 1
	am 2012 No. 1
s 5.17C	ad 2009 No. 1
s 5.17D	ad 2009 No. 1
	am 2012 No. 1
s 5.17E	ad 2009 No. 1
s 5.17F	ad 2009 No. 1
	am 2012 No. 1
s 5.17G	ad 2009 No. 1

Endnote 4—Amendment history

Provision affected	How affected
	am 2012 No. 1
s 5.17H	ad 2009 No. 1
s 5.17I	ad 2009 No. 1
s 5.17J	ad 2009 No. 1
s 5.17K	ad 2009 No. 1
s 5.17L	ad 2009 No. 1
	am 2011 No. 1
	rs 2012 No. 1
	am 2015 No 1; 2016 No 1
Division 5.2.4	
s 5.18	am 2009 No. 1; 2013 No. 1
Division 5.2.5	
s 5.19	am 2012 No. 1
Division 5.2.6	
s 5.22	rs 2013 No. 1
	am 2015 No 1; 2015 No 2
s 5.22AA	ad 2013 No. 1
	am 2015 No 2
Division 5.2.7	ad 2012 No. 1
	rep 2015 No 1
s 5.22A	ad 2012 No. 1
	rep 2015 No 1
s 5.22B	ad 2012 No. 1
	rep 2015 No 1
s 5.22C	ad 2012 No. 1
	rep 2015 No 1
s 5.22D	ad 2012 No. 1
	rep 2015 No 1
s 5.22E	ad 2012 No. 1
	rep 2015 No 1
s 5.22F	ad 2012 No. 1
	rep 2015 No 1
s 5.22G	ad 2012 No. 1
	rep 2015 No 1
s 5.22H	ad 2012 No. 1
	rep 2015 No 1
s 5.22I	ad 2012 No. 1
	rep 2015 No 1
s 5.22J	ad 2012 No. 1
	rep 2015 No 1

Provision affected	How affected
s 5.22K	ad 2012 No. 1
	rep 2015 No 1
s 5.22L	ad 2012 No. 1
	rep 2015 No 1
Division 5.2.7	
Division 5.2.7	ad 2016, No 1
s 5.22A	ad 2016 No 1
s 5.22B	ad 2016 No 1
s 5.22C	ad 2016 No 1
s 5.22D	ad 2016 No 1
s 5.22E	ad 2016 No 1
s 5.22F	ad 2016 No 1
s 5.22G	ad 2016 No 1
s 5.22H	ad 2016 No 1
s 5.22J	ad 2016 No 1
s 5.22K	ad 2016 No 1
s 5.22L	ad 2016 No 1
s 5.22M	ad 2016 No 1
Part 5.3	
Part 5.3 heading	rs 2009 No. 1
Division 5.3.1	
s 5.23	rs 2009 No. 1
	am F2018L00923
s 5.24	am 2009 No. 1
Division 5.3.2	
s 5.25	am 2009 No. 1; 2010 No. 1; 2011 No. 1; 2015 No 1
Division 5.3.3	
s 5.26	am 2009 No. 1
	rs 2014 No. 1
	am 2015 No 1
s 5.26A	ad 2014 No. 1
Division 5.3.5	
s 5.31	rs 2011 No. 1
	am 2012 No. 1; 2015 No 1
Division 5.3.6	
s 5.32	am 2012 No. 1
Division 5.3.8	
s 5.37	am 2012 No. 1
Part 5.4	
Part 5.4 heading	rs 2009 No. 1

Endnote 4—Amendment history

Provision affected	How affected
Division 5.4.1	
s 5.40	rs 2009 No. 1
	am 2011 No. 1; 2013 No. 1; 2014 No. 1
s 5.41	am 2009 No. 1
Division 5.4.2	
s 5.42	am 2009 No. 1; 2011 No. 1; 2013 No. 1; 2014 No. 1; 2015 No 1
Division 5.4.3	
s 5.43	am 2009 No. 1; 2010 No. 1; 2014 No. 1
Division 5.4.5	
s 5.48	am 2012 No. 1
Part 5.5	
Part 5.5 heading	rs 2009 No. 1
s 5.51	am 2009 No. 1; 2014 No. 1
s 5.52	am 2010 No. 1; 2011 No. 1
s 5.53	am 2009 No. 1
Chapter 6	
Part 6.1	
s 6.1	am 2013 No 1
s 6.2	am 2009 No. 1; 2010 No. 1; 2014 No. 1; F2017L00829
s 6.3	am F2017L00829
Part 6.2	
s 6.4	am 2014 No. 1; 2016 No 1
s 6.5	am 2009 No. 1; 2013 No. 1; F2017L00829
Chapter 7	
s 7.1	am 2009 No. 1
	rs 2013 No. 1
	am F2017L00829
s 7.2	am 2009 No 1; 2015 No 2; F2017L00829
s 7.3	ad 2009 No. 1
	am F2017L00829
Chapter 8	
Chapter 8	rs 2009 No. 1
Part 8.1	
s 8.1	rs 2009 No. 1
	am 2016 No 1
Part 8.2	
s 8.2	rs 2009 No. 1
s 8.3	rs 2009 No. 1
	am 2016 No 1
Part 8.3	

Provision affected	How affected
s 8.4	rs 2009 No. 1
	am 2016 No 1
s 8.5	rs 2009 No. 1
	am 2016 No 1
s 8.6	rs 2009 No. 1
	am 2010 No. 1; 2011 No. 1; 2013 No. 1
s 8.7	rs 2009 No. 1
	am 2010 No. 1; 2011 No. 1
s 8.8	rs 2009 No. 1
	am 2011 No. 1
s 8.9	rs 2009 No. 1
	am 2011 No. 1
s 8.10	ad 2009 No. 1
s 8.11	ad 2009 No. 1
	am 2016 No 1
s 8.12	ad 2009 No. 1
	am 2010 No. 1
	rep 2016 No 1
s 8.13	ad 2009 No. 1
	am 2010 No. 1
	rep 2016 No 1
Part 8.4	
s 8.14	ad 2009 No. 1
	am 2016 No 1
s 8.15	ad 2009 No. 1
	am 2012 No. 1
Chapter 9	
Chapter 9	ad 2014 No 1
	rs 2016 No 1
	am 2015 No 2
s 9.1	ad 2014 No 1
	rep 1 Nov 2014 (s 9.1(2))
	ad 2016 No 1
	rep 1 Nov 2016 (s 9.1(2))
s 9.2	ad 2014 No 1
	rep 2016 No 1
s 9.3	ad 2015 No 2
	rep 1 Nov 2015 (s 9.3(2))
s 9.4	ad 2015 No 2
	rep 1 Nov 2015 (s 9.4(2))

Endnote 4—Amendment history

Provision affected	How affected
s 9.5	ad 2015 No 2
	rep 1 Nov 2016 (s 9.5(2))
s 9.10	ad F2017L00829
s 9.11	ad F2018L00923
Schedule 1	
Schedule 1	am 2009 No. 1; 2010 No. 1; 2011 No. 1; 2012 No. 1; 2013 No. 1; 2014 No. 1; 2015 No 1; 2015 No 2; 2016 No 1; F2017L00829; F2018L00923
Schedule 2	
Schedule 2	am 2011 No. 1; 2013 No. 1
Schedule 3	
Schedule 3 heading	rs 2010 No. 1
Schedule 3	am 2009 No. 1; 2010 No. 1; 2011 No. 1; 2012 No. 1; 2013 No. 1; 2015 No 1