

## Australian Government

**Department of the Environment and Energy** 

# National Greenhouse and Energy Reporting Scheme Measurement

# Technical Guidelines for the estimation of emissions by facilities in Australia

Applies to the estimation of emissions in the 2017-18 reporting year

October 2017



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## **Chapter 1—General**

## Part 1.1—Preliminary

## **Division 1.1.1—Overview**

The National Greenhouse and Energy Reporting Act 2007, the Regulations under that Act and the National Greenhouse and Energy Reporting (Measurement) Determination 2008 establish the legislative framework for a national greenhouse and energy reporting system.

These Technical Guidelines embody the latest methods for estimating emissions and are based on the *National Greenhouse and Energy Reporting (Measurement)* Determination 2008 as amended (the Determination)<sup>1</sup> and the *National Greenhouse* and Energy Reporting (Measurement) Amendment (Energy) Determination 2017).

The Technical Guidelines provide additional guidance and commentary to assist Reporters in estimating greenhouse gas emissions for reporting under the NGER system and in general are applicable to the 2017-18 reporting year.

The NGER System has two objectives which are set out in the National Greenhouse and Energy Reporting Act 2007 (the Act).

The first set of objectives comprise:

- a) informing government policy formulation and the Australian public;
- b) meeting Australia's international reporting obligations;
- c) assisting Commonwealth, State and Territory government programs and activities; and

<sup>&</sup>lt;sup>1</sup> The Determination is available at http://www.cleanenergyregulator.gov.au/NGER/Legislation. In these Guidelines, indented text is based on the text of the Determination.

d) avoiding the duplication of similar reporting requirements in the States and Territories.

## Thresholds for reporting

The Act makes reporting mandatory for corporations whose energy production, energy consumption, or greenhouse gas emissions meet certain specified thresholds. These thresholds are detailed in section 13 of the NGER Act and in supporting material available on the Clean Energy Regulator website at: http://www.cleanenergyregulator.gov.au/NGER/Forms-and-resources.

The Determination is made under section 7B and subsection 10 of the Act. It provides methods, and criteria for methods, 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; and
- (d) potential greenhouse gas emissions embodied in an amount of natural gas.

The structure of the Determination is designed to facilitate the integration of corporate and facility level data provided under the Act with international data standards on greenhouse emissions estimates. Descriptions of emissions sources are based on those provided in the *IPCC Guidelines for National Greenhouse Gas Inventories*, while estimation methods are based on those used by the Department on the Environment in preparing the Government's annual submission to the United Nations Framework Convention on Climate Change (UNFCCC) in the *National Inventory Report*.

These Technical Guidelines do not provide guidance on issues concerning the definition of a facility or who should report the emissions from a particular facility. For guidance on these questions, consult the supporting material available on the Clean Energy Regulator website at: http://www.cleanenergyregulator.gov.au/NGER/Forms-and-resources

### Emissions

Scope 1 and scope 2 emissions are defined in the Regulations as the release of greenhouse gas emissions into the atmosphere either as a direct result of an activity that constitute the facility (scope 1) or as a result of activities that consume electricity, heat or steam at the facility (scope 2).

The Determination and Technical Guidelines deal with scope 1 emissions and scope 2 emissions. Gaseous designated fuels are natural gas and liquefied natural gas. The Technical Guidelines are largely concerned with scope 1 emissions. Scope 1 emissions concern emissions released from a facility as a direct result of the activities of the facility.

The greenhouse gases covered by these Guidelines are defined in the Regulations and include:

- carbon dioxide;
- methane;
- nitrous oxide;
- specified hydrofluorocarbons
- specified perfluorocarbons; and
- sulphur hexafluoride.

Scope 2 emissions are a form of indirect emission and are activities that generate electricity, heating, cooling or steam that is consumed by the facility but that do not form part of the facility. They occur principally at electricity generators as a result of electricity consumption at another facility. Scope 2 emissions are covered only in Chapter 7.

Natural gas is defined in the Regulations.

Coverage of Scope 1 emission sources in the Determination is given by the following categories:

 (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 (Chapter 3); and
- (c) industrial processes emissions, which deals with emissions released from the consumption of carbonates and the use of fuels as feedstocks 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 wastewater handling facilities (see Chapter 5).

The most important source is emissions from fuel combustion, which accounts for over 60 per cent of the emissions reported in the national greenhouse gas inventory.

The scope of the Determination does not include land based emissions covered by the UNFCCC categories 'Agriculture' and 'Land Use, Land Use Change and Forestry'. However, emissions from fuel combustion or any other emission source listed above and which occurs from a facility operating within a land-based industry are, nonetheless, covered by the Determination.

#### Updates of these Guidelines

It is recognised that these Technical Guidelines will need to be updated as new information on emissions estimation methods becomes available. This will need to be balanced against the need to maintain time-series consistency of the emissions data as far as possible. Reflecting the need for this balance, it is planned that these Guidelines will be updated each year only for updated Scope 2 emission factors (see Chapter 7), while other revisions will occur on a periodic basis. It is planned that the Technical Guidelines will be updated periodically to:

- provide Methods for emission sources where currently there are gaps or omissions in the Methods currently available;
- take account of new documentary standards applicable to the estimation of emissions under Methods 2, 3 and 4;
- take account of new information in relation to Method 1 emission factors; and

• take account of new information in relation to the Methods detailed in the Determination.

The Department will continue to refine and elaborate the Determination as other issues arise from ongoing consultation, and domestic and international developments.

## 1.4 Overview—methods for measurement

Emissions are rarely measured through direct observation and are most often estimated by reference to readily observable variables that are closely related to greenhouse gas emissions such as the quantity of fossil fuels consumed.

These Guidelines provide Methods that allow for both direct emissions monitoring and the estimation of emissions through the tracking of observable, closely-related variables. This framework reflects the approaches of the international guidelines governing the estimation of national greenhouse gas inventories and, similarly, national practice such as for the *EU Guidelines for the Monitoring and Reporting of Greenhouse Gas Emissions* and the *US EPA Mandatory Greenhouse Gas Reporting Rule.* 

At its simplest, emissions may be estimated by reference to reportable data such as fossil fuel consumption, evidenced by invoices, and the use of specified emission factors provided in these Guidelines. For emissions from fuel combustion, for example, data on consumption of a particular fuel would be multiplied by a specific emission factor for that fuel to generate an emissions estimate.

Greater levels of complexity and measurement effort may in some circumstances produce better estimates of emissions at facility level. This may result from, for example, sampling and analysis of a fuel consumed for its carbon content and other qualities that will affect actual emissions generated by its combustion at a facility. In Australia, this kind of approach to emissions estimation has been used for a number of years in the electricity industry.

Direct monitoring of emissions is also potentially an important approach to emissions estimation. While not common, such direct monitoring already occurs in some form in some instances such as in the coal industry, where state legislation requires the monitoring of methane levels for health and safety reasons.

Each of these broad approaches has been incorporated into the Guidelines as Methods for the estimation of emissions.

In particular four Methods have been described which provide a framework for emissions estimation for a range of purposes.

By drawing on existing emission estimation practices where possible, the Guidelines aim to allow reporters to meet their obligations efficiently. As indicated above, there are many instances where higher order methods (2, 3 and 4 set out below) already reflect current commercial or regulatory practice.

The provision for Reporters to select Methods for the estimation of emissions also allows Reporters to make their own judgements to balance the costs of using the higher-order methods with the benefits of potentially improved emission estimates.

#### A Framework for Method selection

For scope 1 emissions, the four Methods can be broadly described by the following:

#### Method 1: the National Greenhouse Accounts default method

Method 1 provides a class of estimation procedures derived directly from the methodologies used by the Department of the Environment and Energy for the preparation of the *National Greenhouse Accounts*. The use of methodologies from the *National Greenhouse Accounts* also anchors Method 1 within the international guidelines adopted by the UNFCCC for the estimation of greenhouse emissions.

Method 1 specifies the use of designated emission factors in the estimation of emissions. These emission factors are national average factors determined by the Department of the Environment and Energy using the Australian Greenhouse Emissions Information System (AGEIS).

Method 1 is likely to be most useful for emission sources where the source is relatively homogenous, such as from the combustion of standard liquid fossil fuels, where the emissions resulting from combustion will be very similar across most facilities.
Estimates of emissions will be able to be calculated under Method 1 by Reporters using tools provided by the Department of the Environment and Energy.

Method 2: generally a facility-specific method using industry sampling and Australian or international standards listed in the Determination or equivalent for analysis of fuels and raw materials to provide more accurate estimates of emissions at facility level.

Method 2 enables corporations to undertake additional measurements - for example, the qualities of fuels consumed at a particular facility - in order to gain more accurate estimates for emissions for that particular facility.

Method 2 draws on the large body of Australian and international documentary standards prepared by standards organisations to provide the benchmarks for procedures for the analysis of, typically, the critical chemical properties of the fuels being combusted.

Method 2 is likely to be most useful for fuels which exhibit some variability in key qualities, such as carbon content, from source to source. This is the case for coal in Australia.

Method 2 is based on technical guidelines that were used by reporters under the Generator Efficiency Standards program. The possibility to report using this, higher order, approach is extended by the Determination from the electricity industry to all major consumers of fossil fuels.

# Method 3: generally a facility-specific method using Australian or international standards listed in the Determination or equivalent standards for both sampling and analysis of fuels and raw materials

Method 3 is very similar to Method 2, except that it requires, additionally, Reporters to comply with Australian or international documentary standards for sampling (of fuels or raw materials) or equivalent as well as documentary standards for the analysis of fuels.

# Method 4: direct monitoring of emission systems, either on a continuous or periodic basis.

Method 4 provides for a different approach to the estimation of emissions. Rather than analysing the chemical properties of inputs (or in some case, products), Method 4 provides approaches to enable direct monitoring of greenhouse gas emissions arising from an activity. This can provide a higher level of accuracy in certain circumstances, depending on the type of emission process although it is more data intensive than other approaches. Such direct monitoring already occurs, for example, in underground coal mines reflecting the nature of the emission process and the importance of relatively accurate data to support health and safety objectives.

As for Methods 2 and 3, there is a substantial body of documented procedures on monitoring practices and state and territory government regulatory experience that provide the principal sources of guidance for the establishment of such systems.

It is intended that the Reporter may select different methods for each source. For example, the Reporter may select different methods for different fuels and different methods for individual gases, subject to certain restrictions. In part, these differences reflect Method availability. For example, for solid fuels, only Method 1 has been provided for methane and nitrous oxide, reflecting the minor nature of the emission sources, whereas four methods are available for carbon dioxide.

# 1.5 Overview—energy

Methods for the estimation of the energy content of fuels produced and fuels consumed are addressed in Chapter 6. Data collected for the estimation of emissions from fuel combustion as set out in Chapter 2 will serve a dual purpose as the data for the consumption of energy. Separate collections are required, however, for the quantities of production of energy which, in general, do not enter directly into emission estimations.

# 1.6 Overview—scope 2 emissions

These Guidelines principally deal with Scope 1 emissions. These are direct emissions that arise on-site from the activities of a corporation. There are a wide variety of emission sources that require a range of procedures to be described to cover the complexity of the emission pathways. Scope 2 emissions arise principally at an electricity generator, or through the loss of electricity from an electricity transmission network or distribution network, as a result of the purchase of electricity by a corporation. The method for the estimation of scope 2 emissions is given in Chapter 7. Scope 2 emission factors for the consumption of purchased electricity from Australia's major electricity grids are updated annually to reflect the latest data on the mix of electricity generation sources, which is a major determinant of the factors.

# 1.7 Overview—assessment of uncertainty

Chapter 8 deals with the assessment of statistical uncertainty for scope 1 emissions estimates. It is recognised that these calculations of uncertainty can be complex and relatively imprecise. A standardised approach to estimation of uncertainty of emissions estimates has been provided in Chapter 8.

Proposed changes to the NGER Regulations will only require reporters with emissions of more than 25 kilotonnes of  $CO_2$ -e from the combustion of a fuel type, or a source other than fuel combustion to calculate and report the statistical uncertainty associated with their scope 1 emissions. Sources are defined in section 1.10 of the Measurement Determination and fuel types are set out in Schedule 1 of the NGER Regulations.

# **Division 1.1.2—Definitions and interpretation**

Definitions of key terms used in these Guidelines are to be found at Appendix B. These definitions are drawn from both the Regulations and the Determination.

Many of the estimation methods reference documentary standards developed by, inter alia, standards organisations. Section 1.9 indicates that any standard, instrument or other writing must have been in force at 1 July 2012 to be applicable to an emissions estimation method. This means that any standard or similar instrument released after 1 July 2012 is not able to be referenced in a higher-order method. However, it is intended that the Determination will be reviewed at periodic intervals to consider recognition of such newly developed documentary standards.

# **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

Sources of emissions are based on those provided in the *IPCC Guidelines for National Greenhouse Gas Inventories* and are defined in the Determination. The categories of source are listed in the table below and also correspond to a chapter heading in the Determination while the source of emissions in column 3 relate to the divisions within the chapters.

ltem	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
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

ltem	Category of source	Source of emissions				
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 and carbon anode				
3K		Iron, steel or other metal production using an integrated metalworks				
3L		Ferroalloys production				
3M		Aluminium production				
3N		Other metals production				
30		Emissions of hydrofluorocarbons and sulphur hexafluoride gases				
3P		Sodium cyanide production				
4	Waste					
4A		Solid waste disposal on land				
4B		Wastewater handling (industrial)				
4C		Wastewater handling (domestic or commercial)				
4D		Waste incineration				

# 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 also deals with standards;
- (b) Division 1.2.2 provides for methods for measuring emissions.

# **Division 1.2.1—Measurement and standards**

#### 1.12 Measurement of emissions

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

#### **1.13** General principles for measuring emissions

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

- (a) transparency—emission estimates must be documented and verifiable;
- (b) comparability—emission estimates using a particular method and produced by a registered corporation or liable entity in an industry sector must be comparable with emission estimates produced by similar corporations or entities in that industry sector using the same method and consistent with the emission 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 liable entity and the requirements of this Determination, uncertainties in emission 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.

Time series consistency is also an important principle for measuring emissions. Chapter 5 of Volume 1 of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories provides a detailed discussion of the issue. In short reporters should aim to estimate emissions in a time series consistently, which means that as far as possible, the time series should be calculated using a consistent method and data sources over time. Restrictions on the method to be used for a source, provided in Division 1.2.2, and the criteria for measurement, provided in Part 1.3, and Divisions 2.2.5, 2.3.6, 2.4.6 and 4.2.5, have been put in place to promote time series consistency. These principles are derived from those that apply to the preparation of national inventories.

Note that there is a difference in meaning between the common usage of the word "confidence" and its statistical usage in relation to '95% confidence level'. For an explanation of '95% confidence level' please refer to Chapter 8.

# 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.

A standardised approach to estimation of uncertainty of emissions estimates has been provided in Chapter 8.

Proposed changes to the NGER Regulations will only require reporters with emissions of more than 25 kilotonnes of  $CO_2$ -e from the combustion of a fuel type, or a source other than fuel combustion to calculate and report the statistical uncertainty associated with their scope 1 emissions. Sources are defined in section 1.10 of the Measurement Determination and fuel types are set out in Schedule 1 of the NGER Regulations.

# 1.15 Units of measurement

Standard units of measurement are prescribed for the standard reportable items.

Emissions of each greenhouse gas should be estimated and reported in tonnes of CO<sub>2</sub>-equivalent. Conversion factors from tonnes of emissions of each greenhouse gas to tonnes of emissions of carbon dioxide equivalent for that gas are called Global Warming Potentials and are listed in the Regulations and reproduced in Appendix C.

Emission estimation methods utilise standard units of measurement for solid, gaseous and liquid fuels, unless otherwise specified. For gaseous fuels, the standard unit of measurement is cubic metres, although allowance is made for measurement in gigajoules if data is available in those units.

The standard units for fuels should also be used for reporting. For example, solid fuels should be reported in tonnes.

- (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<sub>2</sub>-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 liable entity 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

- 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 sourcemust 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 liable entity 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 entity 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 liable entity 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

The National Greenhouse and Energy Reporting Regulations currently require facilities involved in carbon capture and storage to report fugitive emissions from transport, injection and the storage site as well as the stock of carbon dioxide stored and the amount of carbon dioxide captured, imported and injected (see Regulation 4.12).

This division sets out methods to support the requirements of the regulations for carbon capture and storage.

This division defines the meaning of 'captured for permanent storage' and the requirements allowing facilities that capture carbon dioxide for permanent storage in an underground geological formation to deduct that amount of carbon dioxide in the emissions estimation process for that facility. The storage must be *permanent* and is defined as such only if the carbon dioxide is transferred to an underground geological formation at the requirement of the transferred to an underground geological formation that is regulated under national or State legislation.

Other requirements for carbon capture and storage (CCS) define how the deductions are to be attributed where there are multiple sources or fuels consumed and the measurement criteria to be applied for the carbon dioxide captured.

Methods to estimate fugitive emissions from transport of the carbon dioxide for permanent storage can be found in Part 3.4.

The scope of the amendments for CCS reflects the status of the regulatory framework as well as the technology available for permanent storage of carbon dioxide. The CCS regulatory framework is under development and is not yet comprehensive.

The provisions for CCS should be considered to be a first step in the process of the development of a comprehensive provision for the treatment of carbon capture and storage in the NGER system.

# 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

The amount of carbon dioxide captured for permanent storage may be deducted from the emissions estimate for the relevant source. Where method 4 is used to measure emissions from a facility a deduction for carbon dioxide captured for permanent storage is not required since emissions are measured directly under this method and do not include the carbon dioxide captured for permanent storage. In determining the amount of carbon dioxide that is captured for permanent storage it is considered good practice to measure the volume of the carbon dioxide stream and the concentration of carbon dioxide in the stream at the point of capture.

- (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<sub>2</sub>-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<sub>2</sub>-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

- 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.

#### **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:

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

- (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.

# 1.191 Volumetric measurement—super-compressed greenhouse gas stream

- 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  $\pm 1.5\%$ .

- 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  $\pm 1.5\%$ .
- (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  $\pm 1.5\%$ .
  - 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  $\pm 1.5\%$ .
- (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  $\pm 1.5\%$ .
- (4) If the measuring equipment uses any other type of flow device, the maximum uncertainty of flow measurement must not be greater than  $\pm 1.5\%$ .
- (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  $\pm 0.25\%$  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

Method 4 provides for direct measurement of emissions of greenhouse gases. Such measurement systems can be established, for example, in flues, stacks, pipes or ducts and may be applicable in a number of industries, although not all.

Method 4 establishes a framework for the design, installation, performance and maintenance of direct emissions measurement systems for stationary emission sources and a guide to measurement, recording, and standardised reporting for estimating greenhouse gas emissions.

Two systems for direct emissions monitoring are available including:

- (a) Continuous emissions monitoring (CEM);
- (b) Periodic emissions monitoring (**PEM**).

The use of Method 4 by corporations will likely depend on a number of factors including the type of emissions process, the structures of the facility and any current direct measurement systems that corporations may have in place for measuring pollutants for other purposes.

The general framework for Method 4 draws on the following publications:

- U.S. Environmental Protection Agency. 2003. Code of Federal Regulations: Standards of Performance for New Stationary Sources. Appendix A – *Test Methods*. 40 CFR 60 Appendix A. Washington, D.C. These methods can be obtained from: http://www.epa.gov/ttn/emc/promgate.html
- The Commission of the European Communities, Commission Decision establishing guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and

of the Council. Brussels, 2006. This document can be obtained from: http://ec.europa.eu/index\_en.htm

- The Environmental Protection Agency, Load Calculation Protocol for use by holders of NSW environment protection licenses when calculating assessable pollutant loads. Department of Environment and Conservation (NSW), February 2005. This document can be obtained from: http://www.environment.nsw.gov.au/licensing/lblprotocol/
- Department of Environment and Heritage, National Pollutant Inventory Emission Estimation Manual for Fossil Fuel Electric Power Generation, Version 2.4, March 2005. This document can be obtained from: http://www.npi.gov.au/
- West Australian Department of Environment and Conservation, Department of Environment and Conservation Continuous Emissions Monitoring System (CEMS) Code for Stationary Source Air Emissions, October 2006. This document can be obtained from http://www.dec.wa.gov.au/
  - (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)**

Continuous Emissions Monitoring (CEM) systems are designed to monitor real-time occurrence of emissions. The aim of the CEM method is to provide the framework for calculating emissions and also to provide standards for the location of sampling positions, measurement of flow rates and gas concentrations and the frequency of measurements.

# Subdivision 1.3.2.1—Method 4 (CEM)

# 1.21 Method 4 (CEM)—estimation of emissions

CEM systems may record emissions automatically via a computer or it may be necessary for emissions to be calculated manually. The equation in 1.21 (1) provides a method to be used to calculate emissions manually from direct emissions monitoring under CEM systems. The equation uses the data gathered from flow rate and gas analyser equipment to calculate mass emissions.

In order to convert volumetric flow rates to mass flow rates accurately, direct measurement also requires the measurement of temperature and pressure to reduce the amount of error that is associated with the variability of density factors used to convert from volume of a gas to the mass of a gas. The equation in 1.21 (1) is cited from the report:

 Mark, M., Worrall, R., Mallett, C., and Xue, S. (2001). Measuring and Reporting Greenhouse Gas Emissions. ACARP Project C8061. CSIRO Exploration and Mining Report 805C.

This report can be obtained from: http://www.acarp.com.au/reports.aspx.

(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:

$$\mathbf{M}_{jct} = \frac{\mathbf{M}\mathbf{M}_{j} \times \mathbf{P}_{ct} \times \mathbf{F}\mathbf{R}_{ct} \times \mathbf{C}_{jct}}{8.314 \mathrm{T}_{ct}}$$

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  $16.04 \times 10^{-3}$ ; or
- (b) for carbon dioxide is  $44.01 \times 10^{-3}$ ; or
- (c) for nitrous oxide is  $44.01 \times 10^{-3}$ .

 $P_{ct}$  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<sub>2</sub>-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.

with underground coal mining. Step 1. Calculate the emission rate for each measurement period using the equation in section 1.21.									
Measurement (time)	MM <sub>ct</sub> (CO <sub>2</sub> tonnes per kilomole)	P <sub>ct</sub> (kPa)	FR <sub>ct</sub> (M <sup>3</sup> /sec)	Cjet (v/v)	Gas constant	T <sub>ct</sub> (degrees Kelvin)	Emission rate (CH4 tonnes per sec)	Emission rate (CO2-e tonnes per sec)	
	а	b	с	d	е	f	g	Н	
1.00PM	0.01604	101.300	300	0.009	8.314	295.0	1.79E-03	4.47E-02	
1.15PM	0.01604	101.320	310	0.012	8.314	295.5	2.46E-03	6.15E-02	
1.30PM	0.01604	101.315	307	0.011	8.314	295.4	2.23E-03	5.59E-02	
1.45PM	0.01604	101.315	305	0.010	8.314	295.1	2.02E-03	5.05E-02	
2.00PM	0.01604	101.310	303	0.010	8.314	295.2	2.01E-03	5.02E-02	
2.15PM	0.01604	101.315	304	0.011	8.314	295.3	2.21E-03	5.53E-02	
2.30PM	0.01604	101.320	308	0.011	8.314	295.3	2.24E-03	5.61E-02	
2.45PM	0.01604	101.320	311	0.012	8.314	295.4	2.47E-03	6.17E-02	

Example: Continuous emissions monitoring of CH4 from fugitive emissions associated

Step 2. Calculate the average emissions rate for an hour by summing the emission estimates in column h of the table and divide by the number of sample periods for the hour:

Average emission rate for the first hour (1.00PM to 2.00PM)

= (4.47E-02+6.15E-02+5.59E-02+5.05E-02)/4

 $= 5.32E-02 CO_2$ -e tonnes per second

Average emission rate for the second hour (2.00PM to 3.00PM)

= (5.02E-02+5.53E-02+5.61E-02+6.17E-02)/4

 $= 4.69E-02 CO_2$ -e tonnes per second

Step 3. The mass emissions for the hour is then calculated by multiplying the average emission rate for the hour in step 1 by the number of seconds in an hour, which is 3600.

Therefore:

Emissions for the first hour =  $5.32E-02 \times 3600$ 

191.3 tonnes CO<sub>2</sub>-e for the hour

Emissions for the second hour =  $5.58E-02 \times 3600$ 

201.0 tonnes CO<sub>2</sub>-e for the hour

To aggregate emissions for a period, the hourly emissions estimates are summed together. For example, total emissions between 1.00 and 3.00pm in the above example is calculated by adding together 191.3 and 201.0 tonnes of CO<sub>2</sub>-e which equals 392.3 tonnes of CO<sub>2</sub>-e.

#### 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.

Example: Attributing CO<sub>2</sub> emissions from fuel combustion measured using method 4 where diesel oil and natural gas is consumed

A facility combusts 5,000 kilolitres of diesel oil and 1,800,000 GJ of natural gas in a gas turbine during the reporting year.

The facility elects to use continuous emissions monitoring (CEM) under Method 4 to estimate emissions of carbon dioxide. The reporter estimates a total of 104,852 tonnes  $CO_2$  from this source using continuous emissions monitoring (CEM) during the year.

In order to attribute these emissions to each fuel the carbon content of the two fuels are estimated using the default carbon content factors published in Schedule 3 of the NGER (Measurement) Determination.

 $CO_2$  emissions attributed to fuel x = total CEM emission estimate \* carbon content of fuel x/ carbon content of all fuels

Carbon content of diesel oil = 5,000 kL \* 0.736 t C/kL = 3,680 t C

Carbon content of natural gas = 1,800,000 GJ \* 0.014 t C/GJ = 25,200 t C

 $CO_2$  emissions attributed to diesel oil = total CEM emission estimate \* carbon content of diesel oil/ (carbon content of diesel oil+ carbon content of natural gas)

Emissions attributed to diesel oil = 104852 t CO<sub>2</sub> \* 3,680 t C/ 28,880 t C = 13,361 t CO<sub>2</sub>

Emissions attributed to natural gas = total CEM emission estimate \* carbon content of natural gas/ (carbon content of diesel oil+ carbon content of natural gas)

Emissions attributed to natural gas =  $104852 \text{ t } \text{CO}_2 * 25,200 \text{ t } \text{C}/ 28,880 \text{ t } \text{C} = 91,491 \text{ t } \text{CO}_2$ 

# 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.

CEM systems have a number of specific requirements, including the location of sampling positions, measuring flow rates and gas concentrations and the frequency of measurement. These specific components of CEM systems are founded on internationally recognised standards or methods. The organisations that have been cited include:

- Standards Australia (AS)
- International Organization for Standardization (ISO)
- United States Environmental Protection Agency (US EPA)

A detailed list of the standards cited and how to obtain them can be found in Appendix D.

# 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)

Whereas CEM systems are designed to measure real-time emissions estimates, Periodic Emissions Monitoring (PEM) systems are designed to measure emissions at periodic intervals (e.g. daily, weekly, monthly measurements) over a specified period. The equations for calculating emissions from flow rate and gas concentration data is closely related to that of the CEM approach, however the frequency of measurement and operational time of PEM is less than for CEM.

# 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<sub>2</sub>-e tonnes.
- (3) The average mass emissions rate for the gas measured in CO<sub>2</sub>-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.

Example: Periodic (e.g. monthly sampling regime) emissions monitoring of CH <sub>4</sub> from fugitive emissions associated with underground coal mining								
Measurement (time)	MM <sub>ct</sub> (CO <sub>2</sub> tonnes per kilomole)	P <sub>ct</sub> (kPa)	FR <sub>ct</sub> (M <sup>3</sup> /sec)	C <sub>jct</sub> (v/v)	Gas constant	T <sub>ct</sub> (degrees Kelvin)	Emission estimate (CH4 tonnes per sec)	Emission estimate (CO <sub>2</sub> -e tonnes per sec)
	а	b	с	d	е	f	g	Н
January	0.01604	101.320	270	0.009	8.314	296.0	1.60E-03	4.01E-02
February	0.01604	101.290	255	0.008	8.314	295.6	1.35E-03	3.37E-02
March	0.01604	101.280	260	0.009	8.314	295.4	1.55E-03	3.87E-02
April	0.01604	101.350	275	0.009	8.314	295.1	1.64E-03	4.10E-02
May	0.01604	101.400	280	0.010	8.314	295.5	1.85E-03	4.63E-02
June	0.01604	101.320	265	0.008	8.314	294.3	1.41E-03	3.52E-02
July	0.01604	101.260	260	0.008	8.314	294.0	1.38E-03	3.46E-02
August	0.01604	101.400	285	0.011	8.314	294.4	2.08E-03	5.21E-02
September	0.01604	101.500	295	0.012	8.314	295.5	2.35E-03	5.86E-02
October	0.01604	101.330	270	0.009	8.314	295.6	1.61E-03	4.02E-02
November	0.01604	101.450	290	0.013	8.314	296.2	2.49E-03	6.23E-02
December	0.01604	101.280	255	0.007	8.314	296.5	1.18E-03	2.94E-02

To obtain the annual emission estimate the following steps are then taken.

Step 1. Calculate the average emissions rate for the year by summing the monthly emission rate estimates in column h of table 1 and divide by the number of sample periods:

= (4.01E-02 + 3.37E-02 + 3.87E-02 + 4.10E-02 + 4.63E-02 + 3.52E-02 + 3.46E-02 + 5.21E-02 + 5.86E-02 + 4.02E-02 + 6.23E-02 + 2.94E-02)/12

 $= 4.27E-02 \text{ CO}_2$ -e tonnes per second

Step 2. The emissions for the year are calculated by multiplying the average emission rate for the year in step 1 by the number of seconds in a year, which is 31,536,000. Therefore:

Emissions for the year =  $4.27E-02 \times 31,536,000$ 

= 1,346,062 tonnes CO<sub>2</sub>-e

#### 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.

Example: Attributing  $CO_2$  emissions from fuel combustion measured using method 4 where diesel oil and natural gas is consumed

A facility combusts 5,000 kilolitres of diesel oil and 1,800,000 GJ of natural gas in a gas turbine during the reporting year.

The facility elects to use periodic emissions monitoring (PEM) under Method 4 to estimate emissions of carbon dioxide. The reporter estimates a total of 104,852 tonnes  $CO_2$  from this source during the year.

In order to attribute these emissions to each the carbon content of the two fuels are estimated using the default carbon content factors published in schedule 3 of the NGER (Measurement) Determination.

 $CO_2$  emissions attributed to fuel x = total PEM emission estimate \* carbon content of fuel x/ carbon content of all fuels

Where carbon content of diesel oil = 5,000 kL \* 0.736 t C/kL = 3,680 t C

Where carbon content of natural gas = 1,800,000 GJ \* 0.014 t C/GJ = 25,200 t C

Emissions attributed to diesel oil = total PEM emission estimate \* carbon content of diesel oil/ (carbon content of diesel oil+ carbon content of natural gas)

Emissions attributed to diesel oil =  $104,852t \text{ CO}_2 * 3,680 \text{ t} \text{ C}/ 28,880 \text{ t} \text{ C} = 13,361t \text{ CO}_2$ 

Emissions attributed to natural gas = total PEM emission estimate \* carbon content of natural gas/ (carbon content of diesel oil+ carbon content of natural gas)

Emissions attributed to natural gas =  $104,852t \text{ CO}_2 * 25,200 \text{ t C}/ 28,880 \text{ t C} = 91,491t \text{ CO}_2$ 

# 1.28 Calculation of emission factors

PEM data calculated in Method 4 can be used to calculate emission factors for use in Method 2 by dividing the emissions estimated from a PEM system by the amount of fuel combusted or raw material produced during the year.

- (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.

#### Example

If the annual methane emissions from an underground coal mine was 1,130,729 tonnes CO<sub>2</sub>-e and 2,500,000 tonnes of Run-of-mine (ROM) coal was extracted from the mine, the emission factor would be:

EF = 1 130 729 tonnes  $CO_2$ -e / 2 500 000 tonnes ROM coal

EF = 0.45 tonnes  $CO_2$ -e / tonne ROM coal

The calculation of emission factors may apply to a number of industries including electricity generation and production of industrial products (e.g. nitric acid).

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

# 1.29 Overview

PEM systems have a number of specific requirements, including the location of sampling positions, measuring flow rates and gas concentrations and the frequency of measurement. These specific components of PEM systems are founded on internationally recognised standards or methods. The organisations that have been cited include:

- Standards Australia (AS)
- International Organization for Standardization (ISO)
- United States Environmental Protection Agency (US EPA)

A detailed list of the standards cited and how to obtain them can be found in Appendix D.

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

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

The principle purpose of the combustion of fossil fuels in the Australian economy is for the consumption or use of energy. This chapter addresses the general case of the estimation of emissions from the combustion of fossil fuels for that purpose.

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).

### Reporting context

Under subdivision 4.4.5 of the *Regulations,* Reporters should submit data for each individual fuel type on the quantity of fuel consumed for:

- (a) electricity generation;
- (b) transport (excluding international bunker fuels);
- (c) carbon reductants or feedstocks;
- (d) other stationary energy purposes; and

(e) fuels consumed without combustion.

For each fuel type the Reporter should also submit:

- i) the amount of fuel consumed for each purpose (a) to (e);
- ii) the emissions of each greenhouse gas for each purpose (a) to (d);
- iii) the Method used to estimate the emissions (a) to (d); and
- iv) the criterion used to estimate the amount of fuel consumed (a) to (e).

More detail on the reporting requirements are set out in Part 2.7A.

# Part 2.2—Emissions released from the combustion of solid fuels

### **Division 2.2.1—Preliminary**

### 2.2 Application

From the 2013-14 reporting year the measurement and reporting of emissions and energy associated with the combustion of a solid fuel is optional if the quantity of solid fuel combusted in a separate instance of a source is 1 tonne or less. Separate instance of a source is defined in section 1.9A. Amounts below the reporting threshold may still be reported if doing so is more efficient for the reporter.

> 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

Method 1 is derived from the *National Greenhouse Accounts* national methodology as published in the *National Inventory Report*. Estimates of emissions from the combustion of individual solid fuel types are made by multiplying a (physical) quantity of fuel combusted by a fuel-specific energy content factor and a fuel-specific emission factor for each relevant greenhouse gas (in this case, carbon dioxide, methane and nitrous oxide).

The list of solid fuels for which emissions must be calculated is given in Table 2.2.2 (taken from Schedule 1 of the *Regulations*).

Energy content and emission factors required for the estimation of emissions from the combustion of solid fuels using this approach are given below. These factors are intended to be default factors – to be used in the absence of better information about the qualities of the fuels combusted at a particular facility. (If better information on fuel qualities or emissions is available, the Reporter may utilise Method 2, 3 or 4).

Once selected the energy content factor  $(EC_i)$  for a particular fuel must be applied to all calculations of energy emissions from that fuel for a facility in the reporting year.

The emission factors for use in Method 1 have been estimated using the Australian Greenhouse Emissions Information System (AGEIS) operated by the Department on the Environment. Consequently, they are determined simultaneously with the production of Australia's National Greenhouse Accounts ensuring that inventories of emissions at both facility and corporate levels are consistent with those of the national accounts.

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<sub>2</sub>-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<sub>2</sub>-e per gigajoule according to source as mentioned in Schedule 1.

### Table 2.2.2:Emission and energy content factors — solid

### fuels and certain coal-based products

ltem	Fuel combusted	Energy content factor	Emission factor kg CO₂-e/GJ		tor J
		GJ/t	(RELEVANT OXIDATION FACTORS INCORPORATED)		OATION ORATED)
			CO <sub>2</sub>	CH₄	N <sub>2</sub> O
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

ltem	Fuel combusted	Energy content factor GJ/t	Emission factor kg CO2-e/GJ (RELEVANT OXIDATION FACTORS INCORPORATED)		ctor GJ DATION ORATED)
			CO <sub>2</sub>	CH₄	N <sub>2</sub> O
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
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 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. Notes on the sources of the factors listed above can be found at Appendix 2A.

Additional coal classifications were introduced in the 2012-13 reporting year. The classifications are defined in the NGER Regulations (Regulation 1.03) and are based on Australian Standard AS2096-1987.

The new classifications are defined in NGER Regulation 1.03 as follows:

- Anthracite means coal having a volatile matter of less than 14.0% on a dry ash-free basis.
- **Bituminous** coal means coal having:

(a) a volatile matter of not less than 14.0% on a dry ash-free basis; and

- (b) gross specific energy of either:
  - (i) not less than 26.50 megajoules per kilogram on an ash-free moist basis; or
  - (ii) not less than 24.00 megajoules per kilogram on an ash-free moist basis if the crucible swelling number is not less than one.
- **Sub-bituminous coal** means coal having a gross specific energy of:
  - (a) 19.00–23.99 megajoules per kilogram on an ash-free moist basis; or
  - (b) if the crucible swelling number is 0 or 1/2 19.00–26.49 megajoules per kilogram on an ash-free moist basis.

### Example

A facility consumes 20,000 tonnes of washed bituminous coal for a purpose other than for the production of electricity or coke. The Reporter elects to use Method 1 (*Division 2.2.2*) for each of the three greenhouse emission gases (j) (carbon dioxide, methane and nitrous oxide), for the fuel type bituminous coal. Emissions are estimated as follows:

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

where:

 $E_{ij}$  is the emissions of gas type (*j*) released from the combustion of fuel type (*i*) from the operation of the facility during the year measured in CO<sub>2</sub>-e tonnes.

 $Q_i$  is the quantity of fuel type (*i*) estimated under Division 2.2.5 measured in tonnes. In this case it is 20,000 tonnes of bituminous coal.

 $EC_i$  is the energy content factor of fuel type (*i*) estimated under section 6.5. In this case it is assumed to be 27 gigajoules per tonne for bituminous coal.

 $EF_{ijaxec}$  is the emission factor for each gas (which includes the effect of a default oxidation factor) released from the combustion of fuel type (*i*) measured in kilograms of CO<sub>2</sub>-e per gigajoule according to source as mentioned in Schedule 1. In this case, for carbon dioxide, it is 90.0 kg CO<sub>2</sub>-e per gigajoule for bituminous coal. For methane, the emission factor is 0.03 kilograms per gigajoule and for nitrous oxide, 0.2 kilograms per gigajoule.



### **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

Method 1 applies national emission factors to the estimation of emissions. This approach produces accurate estimates for each facility in the sense that they are expected to be neither over nor under-estimates, but the approach effectively averages out the variations in emission factors for the fuels that might be applicable for a particular facility. Better estimates of emissions at a particular facility may be obtained by sampling and analysing the fuels actually combusted at the facility for the intrinsic qualities of the fuels themselves that affect actual emission levels. These qualities include the carbon, ash and moisture content of a fuel and may vary reasonably significantly from source to source, particularly for coals.

Method 2 is derived from the methodologies published in the *Technical Guidelines for the Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage and is designed to enable more accurate estimates of emissions to be made at a particular facility.

Under Method 2, representative and unbiased samples of fuels consumed must be obtained for analysis. Analysis of the fuels for carbon, energy, ash or moisture content must be done in accordance with listed Australian or international documentary standards or equivalent.

In order to deduct carbon dioxide captured for permanent storage reporters are required to use Method 2 or higher. These higher order methods provide a more accurate estimate of the carbon dioxide emissions than under Method 1, the default method. As the carbon dioxide captured is deducted from the emissions estimate it is necessary to have a greater level of accuracy in the emissions estimate than is achieved using Method 1.

Division 2.2.3 also sets out a further choice for the estimation of emissions from solid fuel combustion, which is to estimate emissions with a) an assumed oxidation factor (sub-division 2.2.3.1) or b) to estimate the oxidation level by reference to additional information about the fuels combusted by the facility (Sub-division 2.2.3.2).

For sub-division 2.2.3.1, oxidation factors are drawn from default factors utilised in the National Greenhouse Accounts.

Once the analysis of the fuel for carbon, ash and moisture has been completed, emissions may then be estimated in accordance with the equations specified in Section 2.5 (1) or 2.6 (1).

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

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

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<sub>2</sub>-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 carbon dioxide emission factor for fuel type (*i*) measured in kilograms of CO<sub>2</sub>-e per gigajoule as worked out under subsection (2).

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-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  $EF_{ico_{2}oxec}$  in subsection (1), estimate as follows:

$$EF_{ico_2 oxec} = \frac{EF_{ico_2 ox,kg}}{EC_i} \times 1000$$

where:

 $EF_{ico_2ox,kg}$  is the carbon dioxide emission factor for fuel type (*i*) measured in kilograms of CO<sub>2</sub>-e per kilogram 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), work out as follows:

$$\mathrm{EF}_{\mathrm{ico}_{2}\mathrm{ox},\mathrm{kg}} = \frac{\mathrm{C}_{\mathrm{ar}}}{100} \times \mathrm{OF}_{\mathrm{s}} \times 3.664$$

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.

# Table 2.2.3Analysis of solid fuels: standards andfrequency of analysis for energy, carbon, moisture and ash

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
1 <b>B</b>	Anthracite	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

ltem	Fuel combusted	Parameter	Standard	Frequency
		Moisture	AS 1038.1—2001 AS 1038.3—2000	Each delivery
		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	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
	from fossil fuels, if recycled and combusted to produce heat or	Carbon	CEN/TS 15407:2006	Monthly sample composite
	electricity	Moisture	CEN/TS 15414-3:2006	Each delivery
		Ash	CEN/TS 15403:2006	Each delivery
9	Non-biomass municipal materials, if recycled	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
	and combusted to produce heat or	Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery

ltem	Fuel combusted	Parameter	Standard	Frequency
		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
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

ltem	Fuel combusted	Parameter	Standard	Frequency
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	Energy content factor	CEN/TS 15400:2006	Monthly sample composite
	items mentioned in items 10 to 15	Carbon	CEN/TS 15407:2006	Monthly sample composite
		Moisture	CEN/TS 15414-3:2006	Each delivery
			CEN/TS 14774-3:2004	
		Ash	CEN/TS 15403:2006	Each delivery

**Example:** A facility consumes 100,000 tonnes of bituminous coal with a carbon content of 75 per cent and an energy content of 28.5 gigajoules per tonne for purposes other than coke or electricity production. The Reporter elects to use Method 2 (*Division 2.2.3*) for the estimation of emissions of carbon dioxide and Method 1 (*Division 2.2.2*) for the estimation of emissions from methane and nitrous oxide.

Carbon dioxide emissions are estimated according to Method 2 as follows:

1. Estimate the carbon dioxide emission factor  $(EF_{ico2ox,kg})$  for fuel type (i) as follows:

$$EF_{ico_2 ox,kg} = \frac{C_{ar}}{100} \times OF_s \times 3.664$$

where:

\_

 $EF_{ico2ox,kg}$  the carbon dioxide emission factor for fuel type (*i*) in kilograms of CO<sub>2</sub>-e per kilogram of fuel;

 $C_{ar}$  is the percentage of carbon in fuel type (*i*) as received for the facility. In this case the percentage of carbon in bituminous coal is estimated to be 75.

 $OF_{s}$ , or oxidation factor, is:

- (a) if the principal activity of the facility is electricity generation -0.99; or
- (b) in any other case -0.98.

 $= 75/100 \ge 0.98 \ge 3.664$ 

= 2.69 kg of CO<sub>2</sub>-e per kg of fuel

2. Estimate the carbon dioxide emission factor for fuel type (i) measured in kilograms of

CO<sub>2</sub>-e per gigajoule as follows: 
$$EF_{ico_2 oxec} = \frac{EF_{ico_2 ox,kg}}{EC_i} \times 1000$$

### where:

 $EF_{ico2ox,kg}$  is the carbon dioxide emission factor for fuel type (i) measured in kilograms of CO<sub>2</sub>-e per kilogram of fuel.

 $EC_i$  is the energy content factor of fuel type (i) estimated under section 6.5. In this case the energy content factor of bituminous coal is estimated to be 28.5 GJ/t.

= 2.69/28.5 x 1 000

= 94.4 kg of CO<sub>2</sub>-e per gigajoule

3. Estimate emissions as follows:

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

### where:

 $E_{ico2}$  means the emissions of carbon dioxide released from the combustion of a fuel type (*i*) from the operation of the facility during the year measured in CO<sub>2</sub>-e tonnes.

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

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

 $\gamma$  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<sub>2</sub> e tonnes.

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

*EF<sub>ico20xec</sub>* is the carbon dioxide emission factor for fuel type (*i*) measured in kilograms of CO<sub>2</sub>-e per gigajoule.

= 100,000 x 28.5 x 96.8/1 000

= 269,040tonnes of carbon dioxide emissions (CO<sub>2</sub>-e).

Methane and nitrous oxide emissions are estimated according to Method 1 as follows:

$$\mathbf{E}_{ij} = \frac{\mathbf{Q}_i \times \mathbf{E} \mathbf{C}_i \times \mathbf{E} \mathbf{F}_{ijoxec}}{1\ 000}$$

where:

 $E_{ij}$  is the emissions of gas type (*j*) released from the combustion of fuel type (*i*) from the operation of the facility during the year measured in CO<sub>2</sub>-e tonnes.

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

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

 $EF_{ijoxee}$  is the emission factor for each gas (which includes the effect of a default oxidation factor) released from the combustion of fuel type (*i*) measured in kilograms of CO<sub>2</sub>-e per gigajoule (Schedule 1).

Emissions of methane from combustion of bituminous coal:

= (100,000 x 28.5 x 0.03)/1 000

= 86 t CO<sub>2</sub>-e

Emissions of nitrous oxide from combustion of bituminous coal:

= (100,000 x 28.5 x 0.2)/1 000

= 570 t CO<sub>2</sub>-e

## 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

Sub-division 2.2.3.2 sets out the second option for the estimation of emissions from solid fuel combustion using an estimated oxidation level by reference to additional information about the fuels combusted by the facility. An alternative approach, using an assumed oxidation factor, is set out in sub-division 2.2.3.1.

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

$$\mathbf{E}_{ico_2} = \frac{\mathbf{Q}_i \times \mathbf{E}\mathbf{C}_i \times \mathbf{E}\mathbf{F}_{ico_2 \text{oxec}}}{1\ 000} - \gamma \mathbf{RCCS}_{co_2}$$

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<sub>2</sub>-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).

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-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:

$$EF_{ico_2 oxec} = \frac{EF_{ico_2 ox,kg}}{EC_i} \times 1\ 000$$

where:

 $EF_{ico_2ox,kg}$  is the carbon dioxide emission factor for the type of fuel measured in kilograms of CO<sub>2</sub>-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:

$$\mathsf{EF}_{\mathsf{i}\mathsf{c}\mathsf{o}_2\mathsf{o}\mathsf{x},\mathsf{k}\mathsf{g}} = \left(\frac{\mathsf{C}_{\mathsf{a}\mathsf{r}}}{100} - \frac{\mathsf{C}_{\mathsf{a}} \times \mathsf{A}_{\mathsf{a}\mathsf{r}}}{(100 - \mathsf{C}_{\mathsf{a}}) \times 100}\right) \times 3.664$$

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:

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

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

Under Method 2, representative and unbiased samples of fuels consumed must be obtained for analysis.

As coal is a heterogeneous material, for the sample to be truly representative it must contain the correct proportions of each particle size present, as well as the correct proportions of particles of varying impurity content. Therefore, in the process of collecting a representative sample, each particle in the lot must have an equal probability of being sampled ('equal selection probability'); the representativeness of the sample being a function of the mass of the sample, or more correctly, the number of particles in the sample.

A mechanical sampling system, designed and operated in accordance with AS 4264 should be used to sample the coal or solid fuel. Ideally, this type of sampling system would be set up to obtain coal as it is either being loaded at the coal source or unloaded at the facility. One lot of coal will normally represent one day or one trainload of coal. If necessary, manual sampling of the coal may be used provided that the sampling equipment and procedure used is in accordance with AS 4264.

Sample preparation as required providing a laboratory sample for analysis is normally carried out in two steps:

Step 1: Initial crushing and subdivision of the samples as part of an operation that is integrated with the coal sampling;

Step 2: Final crushing and subdivision at the laboratory to provide the analysis sample.

Precision is defined as a measure of the extent to which the observations within a set agree with each other; usually expressed as twice the standard deviation (95% confidence level). Precision checks should be carried out on the sampling process to confirm that the sampling rate is acceptable. The procedure for determining the precision of coal sampling and sample preparation is prescribed in AS 4264.5. It is recommended that precision tests be undertaken on a yearly basis and whenever there is a change in the fuel source or a significant change in the quality characteristics of a particular fuel.

If several sources of fuels are being sampled through a given plant, sampling conditions and sample precision checks should be carried out on the source that exhibits the highest degree of heterogeneity.

Bias can be defined as the tendency to obtain a value that is either consistently higher or consistently lower than the reference value; in practice this is the difference between the reference value and the average result obtained from a large number of determinations. The recommended procedure for the estimation of bias in a coal sampling system is given in AS 4264.4. In the case of bias testing of mechanical samplers, the reference samples are usually stopped belt samples off a conveyor belt. For the purposes of verification of a coal sampling system, the coal samples taken for bias testing (pairs consisting of a reference sample and a sample taken by the coal sampler) should be analysed for total moisture and ash.

Bias testing should always be carried out on a new sampling system. For an existing system, the following verification procedure may be followed if there is some doubt about the conformance of the sampling system:

- 1. conduct a detailed technical audit of the sampling system;
- 2. correct any non-conformances that have been observed;
- conduct a limited bias test on the system, usually with the coal that exhibits the widest stochastic variability in total moisture or ash, to provide a more quantitative verification that the sampling system is performing correctly.

Analysis of the fuels for carbon, energy, ash or moisture content must be done in accordance with listed Australian or international documentary standards or by an on-line analyser in accordance with section 2.8 (3). The listing of applicable standards for the analysis of solid fuels is given below. Equivalent standards to those listed may also be used. Examples of equivalent standards include those produced by AS, NZ, ASTM, ISO and CEN standards organisations. The standards must be in force on the date stated in section 1.9. A NATA (National Association of Testing Authorities) accredited laboratory or similar laboratory complying with ISO 17025 should be used to conduct the analysis.

Minimum frequencies of analysis for solid fuels are also provided for in the table below.

### 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

Sampling of furnace and fly ash is needed if the method of sub-division 2.2.3.2 is adopted rather than the alternative method of sub-division 2.2.3.1.

It is recognised that the configuration of plant varies and measurement of carbon in ash should be based on representative operating conditions for the plant.

Furnace ash includes ash collected at the bottom of the furnace hopper of the coal unit and ash collected within the economiser hopper at the rear pass of the coal fired power plant. There is no standard procedure to collecting furnace ash or economiser hopper ash; however, in a wet extraction system, reasonable samples may be obtained by using sampling ladles to collect material from sluiceways. In a dry extraction system, good representative samples can be obtained directly from the conveyor. Particular care should be taken in attempting to obtain samples of furnace ash because of the inherent dangers associated with such operations. The Determination allows for alternative collection methods to be used to obtain samples where it is not feasible due to safety and operational considerations

The legislation sets out the minimum frequency for sampling for carbon in fly ash. It is acknowledged that some facilities sample on a more regular basis and these more frequent measurements should be incorporated into a facilities estimates.

Additional sampling should be undertaken for furnace and fly ash after a significant change in operating conditions as the amount and type of ash produced can vary significantly as a result of the change.

For facilities where load profiles vary significantly throughout the operation of the facility it is recommended that ash is sampled as a function of load.

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	At least every 2 years, or after significant changes in operating conditions

Item	Procedure	Frequency
	4323.2—1995, or in a standard that is equivalent to one of those standards	
2	By using standard industry 'cegrit' extraction equipment	At least every year, or after significant changes in operating conditions
3	<ul><li>By collecting fly ash from:</li><li>(a) the fly ash collection hoppers of a flue gas cleaning plant; or</li><li>(b) downstream of fly ash collection hoppers from ash silos or sluiceways</li></ul>	At least once a year, or after significant changes in operating conditions
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

Method 3 is a variation on Method 2. Method 3 provides for the same requirements as Method 2 except that sampling of fuels should also be conducted in accordance with the Australian or international standards listed in section 2.12 or by an equivalent standard. Once sampling of the fuel has been conducted in accordance with the standard, the analysis of the fuel for carbon, ash and moisture should be conducted as for Method 2. Emissions may then be estimated in accordance with the equations set out in sections 2.5 (1) or 2.6 (1) in Method 2.

## 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	CEN/TS 14778 – 1:2006
	produce heat or electricity	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

Item	Fuel	Standard
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
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.

Fuel types identified in the Determination are as specified in the Regulation, Schedule 1. The fuel types listed principally reflect the lists of fuels used by the Bureau of Resources and Energy Economics (BREE) to prepare Australia's Energy Statistics and report, inter alia, on behalf of the Australian Government to the International Energy Agency.

The quantities of fuels consumed should exclude those quantities consumed for international transport purposes to reflect international reporting requirements for the national inventory. It is intended that this may be achieved by excluding international bunker fuels as defined in *National Greenhouse and Energy Reporting Regulations 2008*, Regulation 1.03, and that the point of differentiation between domestic and international consumption will be identical to that provided by the Customs Act 1901 which is used also for excise and GST purposes.

Division 2.2.5 specifies the criteria for the estimation of the amounts of each solid fuel type combusted from the operation of a facility during a year.

There are four criteria available for the estimation of quantities combusted reflecting differing levels of measurement effort and precision.

Under the National Greenhouse and Energy Reporting Regulations 2008, the criterion chosen by the Reporter to estimate combustion is required to be reported. Measuring equipment calibrated to a measurement requirement mentioned in Sections 2.16 and 2.17 refers to the standards required for measurement to support all commercial transactions covered by the National Measurement Act 1960 and associated instruments.

In Section 2.17 it is intended that measured data for fuels delivered (at the point of sale) would also meet the Criterion AAA under certain circumstances. These circumstances are that stocks of the fuel consumed at the facility are less than 5% of fuel consumption for the facility during the year and that the stock changes by less than 1% during the year. It is intended that the analysis may be conducted by the supplier.

The simplified measurement of consumption criterion is available in those cases where the Reporter does not purchase their fuel and where the Reporter also does not have metering equipment installed that meets the requirements of criterion AAA. In these cases, it is intended that Reporters should estimate consumption using metering devices or measurement techniques in practice in the industry. Such measurements would need to meet the criteria set out in section 1.13 of transparency, comparability, accuracy and completeness. Such data would be classified and reported as 'BBB' data.

The restriction on the choice of criteria at 2.14 (3) is designed to ensure time series consistency of the measurements.

### 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  $Q_i$  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.	Mair	ntain 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		
		<ul> <li>(ii) solid fuel sampling and measurements provided by measuring equipment calibrated to a measurement requirement; and</li> </ul>		
	(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.			

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 providedby measuring equipment calibrated to a measurementrequirement; 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.

#### Example - Estimating coal consumption using the survey approach

A facility reports consumption of sub-bituminous coal using the survey approach under criteria AA.

Step 1: At 2pm on 27 June, near the end of the reporting year, the facility measures the bulk density of the stockpile and estimates the volume of solid fuel in the stockpile. The resulting estimate is a stockpile of 52,000 tonnes of sub-bituminous coal.

Step 2: The current book value is now 52,000 tonnes.

Step 3:

- a) On 28 June a delivery of 21,530 tonnes is received by train and on 30 June a delivery of 25,690 tonnes is received by train. The deliveries are evidenced by invoices.
- b) Sub bituminous coal consumption from 2pm-midnight on 27 June was estimated to be 6,543 tonnes. Consumption was estimated to be 15,128, 16,425 and 15,303 tonnes on 28, 29 and 30 June respectively. Fuel consumption was estimated based on the measured 'as fired' belt weigher readings adjusted for stocks held in unit bunkers.

The book value as at 30 June is = Book value reported at step 2 +deliveries – fuel consumed.

The book value as at 30 June is = 52,000 + 21,530 + 25,690 - 6,543 - 15,128 - 16,425 - 15,303 = 45,821 tonnes of sub-bituminous coal.

Step 4:

The book value at the end of the reporting period is 45,821 tonnes. This value is used to estimate the change in the quantity of the stockpile of the fuel over the reporting year.

(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.

### Example A Estimating coal consumption using the error allowance approach – stockpile estimate within error tollerence

A facility reports consumption of sub-bituminous coal using the error allowance approach under criteria AA. The book quantity of the stockpile as at 2pm on 27 June is 51,917 tonnes.

Step 1: At 2pm on 27 June, near the end of the reporting year, the facility measures the bulk density of the stockpile and worked out the volume of solid fuel in the stockpile. The resulting estimate is a stockpile of 52,851 tonnes of sub-bituminous coal.

Step 2: The error tolerance for the stockpile at this facility is estimated to be 4%.

Step 3: The current book value is 51,917 tonnes and the quantity of sub-bituminous coal in the stockpile estimated under step 1 is estimated to be 52,851 tonnes. The difference between the two estimates is 1.8%.

Step 4: The difference worked out under step 3 is less than the error tolerance of 4%. Therefore the book value of is retained 51,917 tonnes is maintained.

On 28 June a delivery of 21,530 tonnes is received by train and on 30 June a delivery of 25,690 tonnes is received by train. The deliveries are evidenced by invoices.

Sub bituminous coal consumption from 2pm-midnight on 27 June was estimated to be 6,543 tonnes. Consumption was estimated to be 15,128, 16,425 and 15,303 tonnes on 28, 29 and 30 June respectively. Fuel consumption was estimated based on the measured 'as fired' belt weigher readings adjusted for stocks held in unit bunkers.

The book value as at 30 June is = Book value as at 2pm on 27 June + deliveries – fuel consumed. The book value as at 30 June is = 51,917 + 21,530 + 25,690 - 6,543 - 15,128 - 16,425 - 15,303 = 45,738 tonnes of sub-bituminous coal.

The book value at the end of the reporting period is 45,738 tonnes. This value is used to estimate the change in the quantity of the stockpile of the fuel over the reporting year.

### Example B Estimating coal consumption using the error allowance approach - stockpile estimate greater then error tollerence

A facility reports consumption of sub-bituminous coal using the error allowance approach under criteria AA. The book quantity of the stockpile as at 2pm on 27June is 51,917 tonnes.

Step 1: At 2pm on 27 June, near the end of the reporting year, the facility measures the bulk density of the stockpile and worked out the volume of solid fuel in the stockpile. The resulting estimate is a stockpile of 54,625 tonnes of sub-bituminous coal.

Step 2: The error tolerance for the stockpile at this facility is estimated to be 4%.

Step 3: The current book value is 51,917 tonnes and the quantity of sub-bituminous coal in the stockpile estimated under step 1 is estimated to be 54,625 tonnes. The stockpile estimate is 5.2% greater than the current book value.

Step 4: Step 4 is not applicable because the difference worked out under step 3 is greater than the error tolerance of 4.0%.

Step 5: The difference worked out under step 3 is greater than the error tolerance of 4%. Therefore the book value is adjusted by the difference between the percentage worked out under step 3 (5.2%) and the error tolerance worked out under step 2 (4.0%).

Revised book quantity = Current book value + Difference between estimated stockpile and the book value – error tolerance \* book value

Revised book quantity = 51,917 + (54,625-51,917) - (0.04 \* 51,917) = 52,548 tonnes of subbituminous coal.

On 28 June a delivery of 21,530 tonnes is received by train and on 30 June a delivery of 25,690 tonnes is received by train. The deliveries are evidenced by invoices.

Sub bituminous coal consumption from 2pm-midnight on 27 June was estimated to be 6,543 tonnes. Consumption was estimated to be 15,128, 16,425 and 15,303 tonnes on 28, 29 and 30 June respectively. Fuel consumption was estimated based on the measured 'as fired' belt weigher readings adjusted for stocks held in unit bunkers.

The book value as at 30 June is = Book value as at 2pm on 27 June + deliveries – fuel consumed.

The book value as at 30 June is = 52,548 + 21,530 + 25,690 - 6,543 - 15,128 - 16,425 - 15,303 = 46,369 tonnes of sub-bituminous coal.

The book value at the end of the reporting period is 46,369 tonnes of sub-bituminous coal. This value is used to estimate the change in the quantity of the stockpile of the fuel over the reporting year.

- (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.

For AAA, calibration of the weighing system should be carried out as per the manufacturer's instructions and at least on an annual basis. Some types of weighing systems, such as belt weighers, will require more frequent calibration. Calibration masses should be traceable to the appropriate National Standard of measurement.

The maximum permissible errors for weighers set out in the *National Measurement Act 1960* and associated instruments are given in the table.

### Maximum permissible errors for hopper weighers, belt weighers and automatic rail weighbridges for initial verification and when the equipment is in-service

Weigher	Accuracy Class	Maximum Permissible Error	
		I.V.	I.S.
Hopper weighers <sup>1</sup>	Class 0.2	±0.10%	±0.2%
	Class 0.5	±0.25%	±0.5%
	Class 1	±0.50%	±1.0%
	Class 2	±1.00%	±2.0%
Belt weighers (dynamic	Class 0.5	±0.25%	±0.5%
conditions) <sup>2</sup>	Class 1.0	±0.5%	±1.0%
	Class 2.0	±1.0%	±2.0%
Automatic Rail-weighbridges (%	Class 0.2	±0.10%	±0.2%
or weight of single wagon or	Class 0.5	±0.25%	±0.5%
total train, as appropriate) <sup>2</sup>	Class 1	±0.50%	±1.0%
	Class 2	±1.00%	±2.0%

I.V. = Initial verification

I.S. = In-service

Source: National Measurement Institute NMI R 107 Discontinuous Totalising Automatic Weighing Instruments (Totalising Hopper Weighers)<sup>1</sup>

National Measurement Regulations 1999<sup>2</sup>

Accuracy classes are defined in the National Measurement Regulations 1999 and NMI R 107 document

### Maximum permissible errors for weigh bridges (static conditions) for initial verification and when the equipment is in-service

Maximum permissible errors	for loads m expressed in verification scale intervals e				
initial verification	Class I	Class II	Class III	Class IIII	
±0.5 e	0 ≤ m ≤ 50 000	0 ≤ m ≤ 5 000	0 ≤ m ≤ 500	0 ≤ m ≤ 50	
±1 e ±1.5 e	50 000 < m ≤ 200 000 200 000 < m	5 000 < m ≤ 20 000 20 000 < m ≤ 100 000	500 < m ≤ 2 000 2 000 < m ≤ 10 000	50 < m ≤ 200 200 < m ≤ 1 000	
In service	Class I	Class II	Class III	Class IIII	
±1.0 e	0 ≤ m ≤ 50 000	0 ≤ m ≤ 5 000	0 ≤ m ≤ 500	0 ≤ m ≤ 50	
±2.0 e ±3.0 e	50 000 < m ≤ 200 000	5 000 < m ≤ 20 000 20 000 < m ≤ 100 000	500 < m ≤ 2 000 2 000 < m ≤ 10 000	50 < m ≤ 200 200 < m ≤ 1 000	
	200 000 < m				

Source: National Measurement Institute NMI R 76-1 Non-automatic Weighing Instruments. Part 1:

Metrological and Technical Requirements - Tests

Accuracy classes for weigh bridges as defined in NMI R 76-1 document are:

Special accuracy – Class I

High accuracy - Class II

Medium accuracy - Class III

Ordinary accuracy - Class IIII

### 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

From the 2013-14 reporting year the measurement and reporting of emissions and energy associated with the combustion of a gaseous fuel is optional if the quantity of gaseous fuel combusted in a separate instance of a source is 1,000 cubic metres or less. Separate instance of a source is defined in section 1.9A. Amounts below the reporting threshold may still be reported if doing so is more efficient for the reporter.

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

As for solid fuels, Method 1 for gaseous fuels is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report.* Emissions for each gas type - carbon dioxide, methane or nitrous oxide - are estimated for individual fuel types by multiplying a (physical) quantity of fuel combusted by a fuel-specific energy content factor and a fuel-specific emission factor for each relevant greenhouse gas.

The list of gaseous fuels for which emissions must be calculated is given in Table 2.3.2A and 2.3.2B (taken from Schedule 1 of the National Greenhouse and Energy Reporting Regulations 2008).

Energy content and emission factors required for the estimation of emissions using this approach are given below. These factors are intended to be default factors – to be used in the absence of better information.

Once selected the energy content factor (ECi) for a particular fuel must be applied to all calculations of energy emissions from that fuel for a facility in the reporting year. The emission factors listed have been estimated using the Australian Greenhouse Emissions Information System (AGEIS) operated by the Department on the Environment. Consequently, they are determined simultaneously with the production of Australia's National Greenhouse Accounts ensuring that Reporter inventories are consistent with those national accounts.

### 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<sub>2</sub>-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<sub>2</sub>-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.

(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.

# Table 2.3.2AEmission and energy content factors —gaseous fuels

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

ltem	Fuel combusted	Energy content factor (GJ/m <sup>3</sup> unless otherwise indicated)	E (RELE FACTOF	mission fac kg CO <sub>2</sub> -e/G EVANT OXID RS INCORP(	tor J IATION DRATED)
			CO <sub>2</sub>	CH₄	N <sub>2</sub> O
17	Natural gas distributed in a pipeline	$39.3 \times 10^{-3}$	51.4	0.1	0.03
18	Coal seam methane that is captured for combustion	$37.7 \times 10^{-3}$	51.4	0.2	0.03
19	Coal mine waste gas that is captured for combustion	$37.7 \times 10^{-3}$	51.9	4.1	0.03
20	Compressed natural gas that has reverted to standard conditions	$39.3 \times 10^{-3}$	51.4	0.1	0.03
21	Unprocessed natural gas	$39.3  imes 10^{-3}$	51.4	0.1	0.03
22	Ethane	$62.9  imes 10^{-3}$	56.5	0.03	0.03
23	Coke oven gas	$18.1  imes 10^{-3}$	37.0	0.03	0.05
24	Blast furnace gas	$4.0  imes 10^{-3}$	234.0	0.0	0.03
25	Town gas	$39.0  imes 10^{-3}$	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	$39.3 \times 10^{-3}$	51.4	0.1	0.03
28	Landfill biogas that is captured for combustion (methane only)	$37.7 \times 10^{-3}$	0.0	4.8	0.03
29	Sludge biogas that is captured for combustion (methane only)	$37.7 \times 10^{-3}$	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)	$37.7 \times 10^{-3}$	0.0	4.8	0.03

Notes on the sources of the factors listed above can be found at Appendix 2A.

# Table 2.3.2BEmissions and energy content factors —<br/>gaseous fuels for transport energy<br/>purposes

ltem	Fuel combusted	Energy content factor (GJ/kL unless otherwise	E (RELE FACTOF	mission fac kg CO₂-e/G EVANT OXIE RS INCORP(	tor J DATION ORATED)
		indicated)	CO2	CH₄	N <sub>2</sub> O
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

Notes on the sources of the factors listed above can be found at Appendix 2A.

Definitions of the light and heavy duty vehicles for the purposes of applying gaseous fuels emissions factors can be found in

Appendix B: Definitions and interpretation.

### 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

As for solid fuels, Method 1 applies national average factors to the estimation of emissions. More accurate estimates of emissions at a facility level may be obtained by sampling and analysing fuels for qualities that affect emission levels when the fuel is combusted. These qualities include the composition of the constituent gases of the fuel combusted – for example, the share of methane in the combusted gas.

Method 2 is designed to enable more accurate estimates of emissions at a particular facility.

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

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

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<sub>2</sub>-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<sub>2</sub>-e per gigajoule and calculated in accordance with section 2.22.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-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  $EF_{i,CO_2ox,kg}$  in accordance with the following formula:

$$\mathrm{EF}_{i, \mathrm{CO2,ox,kg}} = \Sigma_{y} \left[ \left( \frac{\mathrm{mol}_{y}\% \times (\frac{\mathrm{mW}_{y}}{\mathrm{V}}) \times 100}{\mathrm{d}_{y, \mathrm{total}}} \right) \times \left( \frac{44.010 \times \mathrm{f}_{y} \times \mathrm{OF}_{g}}{(\mathrm{mW}_{y} \times 100)} \right) \right]$$

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:

$$d_{y, total} = \Sigma_y \operatorname{mol}_y \% \times (\frac{mW_y}{V})$$

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
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:

$$EF_{i CO_2 \text{oxec}} = EF_{i,CO_2 \text{ox,kg}} \div \left(\frac{EC_i}{C_i}\right)$$

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

Under Method 2, representative and unbiased samples of fuels consumed must be obtained for analysis. Analysis of the fuels for composition of constituent gases must be done in accordance with listed Australian or international standards. A listing of applicable standards is given in Section 2.23. Equivalent standards may also be selected. Examples of equivalent standards include those produced by AS, NZ, ASTM, ISO and CEN standards organisations. The standards must be on the date stated in section 1.9.

A NATA (National Association of Testing Authorities) accredited laboratory or similar laboratory complying with ISO 17025 should be used to conduct the analysis.

Minimum frequencies of analysis of the gaseous fuels are also provided for in Section 2.25. With the results of the analysis, emissions may then be estimated in accordance the equations specified in Method 2.

### 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	ASTM D 1826—94 (2003)	ASTM D 1945—03 ASTM D 1946—90 (2006)
	pipeline	ASTM D 7164—05	ISO 6974
		ASTM 3588—98	part 1 (2000)
		(2003)	part 2 (2001)
		ISO 69/4	part 3 (2000)
		part 1 (2000)	part 4 (2000)
		part 2 (2001)	part 5 (2000)
		part 3 (2000)	part 6 (2002)
		part 4 (2000)	GPA 2145 – 03
		part 5 (2000)	GPA 2261 – 00
		part 6 (2002)	
		ISO 69/6:1995	
2	0.1	GPA 21/2—96	A GTN A D 1045 02
Ζ	Coal seam methane that is	ASTM D 1826—94 (2003)	ASTM D 1945—03
	captured for	(2005) ASTM D 7164—05	ASTM D 1946—90 (2006)
comb	combustion	ISO 6974	ISO 6974
		part 1 (2000)	part 1 (2000)
		part 2 (2001)	part 2 (2001)
		part 3 (2000)	part $3(2000)$
		part 4 (2000)	part = (2000)
		part 5 (2000)	part 6 (2002)
		part 6 (2002)	CPA 2145 03
		ISO 6976:1995	CPA 2261 = 00
		GPA 2172—96	GI A 2201 – 00
3	Coal mine	ASTM D 1826 – 94	ASTM D 1945 – 03
	waste gas that is	(2003)	ASTM D 1946 – 90 (2006)
	captured for	ASTM D 7164 – 05	ISO 6974
	combustion	ASTM 3588—98	part 1 (2000)
		(2003)	part 2 (2001)
		ISO 6974	part 3 (2000)
		part 1 (2000)	part 4 (2000)
		part 2 (2001)	part 5 (2000)
		part 3 (2000)	part 6 (2002)
		part 4 (2000)	GPA 2145 – 03
		part 5 (2000)	GPA 2261 – 00
		part 6 (2002)	

Item	Fuel type	Energy content	Gas Composition
		ISO 6976:1995	
		GPA 2172—96	
4	Compressed	ASTM 3588—98	N/A
	natural gas	(2003)	
5	Unprocessed	ASTM D 1826—94	ASTM D 1945—03
	natural gas	(2003)	ASTM D 1946—90 (2006)
		ASTM D 7164—05	ISO 6974
		ISO 6974	part 1 (2000)
		part 1 (2000)	part 2 (2001)
		part 2 (2001)	part 3 (2000)
		part 3 (2000)	part 4 (2000)
		part 4 (2000)	part 5 (2000)
		part 5 (2000)	part 6 (2002)
		part 6 (2002)	GPA 2145 – 03
		ISO 6976:1995	GPA 2261 – 00
		GPA 2172—96	
6	Ethane	ASTM D 3588 – 98	ASTM D 1945 – 03
		(2003)	ASTM D 1946 – 90 (2006)
		ISO 6976:1995	
7	Coke oven gas	ASTM D 3588—98	ASTM D 1945—03
		(2003)	ASTM D 1946—90 (2006)
0	Dlast from a sa	15U 0970:1995	ASTM D 1045 02
8	gas	ASTM D 5588—98 (2003)	ASTM D 1945—03
	Sus	(2005) ISO 6976·1995	ASTM D 1946—90 (2006)
9	Town gas	ASTM D 1826—94	ASTM D 1945-03
,	rown gus	(2003)	ASTM D 1945 - 00 (2006)
		ASTM D 7164—05	ISO 6974
		ISO 6974	nart 1 (2000)
		part 1 (2000)	part 2 (2001)
		part 2 (2001)	part $2(2001)$
		part 3 (2000)	part 4 (2000)
		part 4 (2000)	part $= (2000)$
		part 5 (2000)	part 6 (2002)
		part 6 (2002)	GPA 2145 = 03
		ISO 6976:1995	GPA 2261 = 00
		GPA 2172—96	GIA 2201 – 00
10	Liquefied	ISO 6976:1995	ASTM D 1945 – 03
-	natural gas		ISO 6974
	-		

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

Item	Fuel type	<b>Energy content</b>	Gas Composition	
		part 5 (2000)	part 6 (2002)	
		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.

1 Pipeline quality gases Gas composition Monthly   1 Pipeline quality gases Gas composition Monthly—if category 1 or 2 gas measuring equipment is used   1 Continuous—if category 3 or 4 gas measuring equipment is used	Item	Fuel	Parameter	Frequency
	1	Pipeline quality gases	Gas composition Energy content	Monthly Monthly—if category 1 or 2 gas measuring equipment is used Continuous—if category 3 or 4 gas measuring equipment is used

Item	Fuel	Parameter	Frequency
2	All other gases (including fugitive emissions)	Gas composition Energy content	Monthly, unless the reporting corporation or liable entity 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

As for solid fuels, Method 3 is a variation on Method 2. Method 3 provides for the same requirements as Method 2 except that sampling of fuels should also be conducted in accordance with the Australian or international standards listed below or by an equivalent standard. Once sampling of the fuel has been conducted in accordance with the standard, the analysis of the fuel should be conducted as for Method 2. Emissions may then be estimated in accordance with the equations specified in Section 2.21 (1) in Method 2.

### 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	

Item	Gaseous fuel	Standard	
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)	
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	ISO 10715:1997	
	for combustion	ASTM D 5287–97 (2002)	
		ASTM F 307-02 (2007)	
		ASTM D 5503–94 (2003)	
		GPA 2166–05	
12	Sludge biogas that is captured	ISO 10715:1997	
	for combustion	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	ISO 10715:1997	
	combustion, other than those	ASTM D 5287–97 (2002)	
	mentioned in items 11 and 12	ASTM F 307-02 (2007)	
		ASTM D 5503–94 (2003)	

Item	Gaseous fuel	Standard	
		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

Section 2.27 sets out a Method 2 for methane emissions from the combustion of gaseous fuels. The quantity of methane emissions from the combustion of fuels depends on the equipment used. In the case of gaseous fuels, small variations in emissions are possible. Consequently, in this Method emissions may be estimated by substituting equipment-specific methane emission factors drawn from 2006 IPCC Guidelines for National Greenhouse Gas Inventories (Volume 2) for the methane emission factors listed in the Table in Section 2.20.

### 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.

The quantity of consumption of each of the fuel types specified in the Regulations, Schedule 1, are to be estimated according to one of the criterion set out below.

The fuel types listed principally reflect the lists of fuels used by the Department of Industry to prepare Australia's Energy Statistics and report, inter alia, on behalf of the Australian Government to the International Energy Agency.

Separate estimates of the quantities of each fuel type consumed for the purpose of making electricity; for use as reductants or feedstocks; for use in transport (excluding international bunker fuels) and other stationary energy are required.

The quantities of fuels consumed for transport should exclude those quantities consumed for international transport purposes, if any, to reflect international reporting requirements for the national inventory. It is intended that this may be achieved by excluding international bunker fuels as defined in National Greenhouse and Energy Reporting Regulations 2008, Regulation 1.03, and that the point of differentiation between domestic and international consumption will be identical to that provided by the *Customs Act 1901* which is used also for excise and GST purposes.

As for solid fuels, there are four criteria available for the estimation of quantities combusted. Under the National Greenhouse and Energy Reporting Regulations 2008, the criterion chosen will need to be reported.

The criteria include:

(a) Criterion A - the amount of the fuel delivered for the facility during the year as evidenced by invoices or delivery records issued by the vendor of the fuel (2.29);

(b) Criterion AA - indirect measurement at the point of consumption - based on the amount of fuel delivered for the facility and adjusted for changes in stocks (2.30);

(c) Criterion AAA - direct measurement at the point of consumption - based on the amount of fuel combusted as estimated by measurement equipment that comply with specified standards (2.31 - 2.37);

(d) Criterion BBB - simplified measurement of consumption (2.38).

Measuring equipment requirements set out in Sections 2.31 to 2.37 are drawn from the requirements set out in the *Technical Guidelines for the Generator Efficiency Standards* program for gaseous fuels. These standards have been broadened to provide for a measurement threshold that is not technology-specific (2.35 (4)), reflecting comparable State-specific thresholds for small to medium-sized consumers.

In Sections 2.31 it is intended that measured data for fuels delivered would also meet the Criterion AAA under certain circumstances. These circumstances are that stocks of the fuel consumed at the facility are less than 5% of fuel consumption for the facility during the year and that the stock changes by less than 1% during the year.

The simplified measurement of consumption criterion is available in those cases where the Reporter does not purchase fuel and where the Reporter also does not have metering equipment installed that meets the requirements of criterion AAA. In these cases, it is intended that Reporters should estimate consumption using metering devices or measurement techniques in practice in the industry. Such measurements would need to meet the criteria set out 1.13 - of transparency, comparability, accuracy and completeness, and would be classified and reported as 'BBB' data.

For landfill gas, the BBB criterion includes provision for the estimation of gas quantities based on the practice available under the NSW GGAS scheme – see the notice, *Determining the energy content of waste methane under the generation rules*, NSW IPART, 1 December 2006.

The restriction on the choice of criteria at 2.29 (3) is designed to ensure time series consistency of the measurements.

### 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).

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%

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

- (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  $\pm 1.5\%$ .
    - 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  $\pm 1.5\%$ .
  - (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  $\pm 1.5\%$ .
    - 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  $\pm 1.5\%$ .
  - (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  $\pm 1.5\%$ .
    - 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  $\pm 1.5\%$ .
  - (4) If the measuring equipment uses any other type of flow device, the maximum uncertainty of flow measurement must not be greater than  $\pm 1.5\%$ .
  - (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)  $\pm 0.15\%$  for use in calculation of gross calorific value; and
  - (ii)  $\pm 0.25\%$  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.

	CO <sub>2</sub>	CH4	N <sub>2</sub> O
Method 1	Section 2.41	Section 2.41	Section 2.41
Method 2	Sections 2.42	Section 2.48	Section 2.48
Method 3	Section 2.47		
Method 4	Part 1.3		

Summary of available Methods by emissions of gas type (j)

### Subdivision 2.4.1.2—Liquid fuels—petroleum based oils and greases

### 2.40A Available methods

- 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

As for solid and gaseous fuels, Method 1 is derived from the *National Greenhouse Accounts* national methodology as published in the *National Inventory Report*. Emissions are estimated for individual fuel types by multiplying a (physical) quantity of fuel combusted by a fuel-specific energy content factor and a fuel-specific emission factor for each relevant greenhouse gas (in this case, carbon dioxide, methane and nitrous oxide).

The list of liquid fuels for which emissions must be calculated is given in Appendix A (taken from Schedule 1 of the National Greenhouse and Energy Reporting Regulations 2008).

Energy content and emission factors required for the estimation of emissions using this approach are given below. These factors are intended to be default factors – to be used in the absence of better information.

Once selected the energy content factor  $(EC_i)$  for a particular fuel must be applied to all calculations of energy emissions from that fuel for a facility in the reporting year.

The emission factors listed have been estimated using the *Australian Greenhouse Emissions Information System (AGEIS)* operated by the Department on the Environment. Consequently, they are determined simultaneously with the production of *Australia's National Greenhouse Accounts* ensuring that Reporter inventories are consistent with those *national accounts*.

Equipment specific factors for methane and nitrous oxide are provided for transport fleets. It is intended that the methane and nitrous oxide factors applicable to particular transport fleet should be utilised in the estimation of emissions for the fuel combusted for those fleets. No transport factors are provided for vehicles not registered for road use. Stationary energy factors for individual fuel types should be used in these cases.
# 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<sub>2</sub>-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<sub>2</sub>-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.

# Table 2.4.2AEmission and energy content factors — liquid<br/>fuels and certain petroleum-based products<br/>for stationary energy purposes

ltem	Fuel combusted	Energy content factor (GJ/kL unless otherwise indicated)	Emission factor kg CO <sub>2</sub> -e/GJ (RELEVANT OXIDATION FACTORS INCORPORATE		ctor SJ DATION PORATED)
			CO <sub>2</sub>	CH₄	N <sub>2</sub> O
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

ltem	Fuel combusted	Energy content factor	Emission factor kg CO <sub>2</sub> -e/GJ		ctor 3J
		(GJ/kL unless otherwise indicated)	(RELEVANT OXIDATION FACTORS INCORPORATED)		DATION ORATED)
			CO <sub>2</sub>	CH4	N <sub>2</sub> O
49	Petroleum based products other than:	34.4	69.8	0.0	0.2
	<ul><li>(a) petroleum based oils and petroleum based greases mentioned in items 31 and 32; and</li></ul>				
	(b) the petroleum based products mentioned in items 33 to 48.				
50	Biodiesel	34.6	0.0	0.07	0.2
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

Notes on the sources of the factors listed above can be found at Appendix 2A.

Note: The *National Greenhouse and Energy reporting Regulations 2008* makes reference to Petroleum Coke as being a solid substance under Section 1.03. However, for the purposes of estimating emissions under the NGER (Measurement) Determination 2008, Petroleum coke is classified in Part 3 of Schedule 1 under "Liquid and other certain petroleum-based products". This classification is consistent with IPCC Guidelines and the International Energy Agency fuel classification system.

# Table 2.4.2BEmissions and energy content factors —fuels for transport energy purposes

ltem	Fuel combusted	Energy content factor	Emission factor kg CO <sub>2</sub> -e/GJ		ictor GJ
		(GJ/kL unless otherwise indicated)	(RELEVANT OXIDATION FACTORS INCORPORATE		IDATION PORATED)
			CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
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

ltem	Fuel combusted	Energy content factor (GJ/kL unless otherwise indicated)	Emission factor kg CO2-e/GJ (RELEVANT OXIDATION FACTORS INCORPORATEI		ictor GJ IDATION PORATED)
			CO <sub>2</sub>	CH₄	N <sub>2</sub> O
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

Notes on the sources of the factors listed above can be found at Appendix 2A.

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

As for solid and gaseous fuels, Method 1 applies national average factors to the estimation of emissions. More accurate estimates of emissions at a facility level may be obtained by sampling and analysing fuels for qualities that affect emission levels when the fuel is combusted. These qualities include the fuel's carbon content which may vary from fuel to fuel, albeit reasonably marginally for standard commercial fuels.

The list of liquid fuels for which emissions must be calculated is given in Table 2.4.3 (taken from Schedule 1 of the National Greenhouse and Energy Reporting Regulations 2008).

# 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:

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

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<sub>2</sub>-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.

 $EF_{iCO_{2}oxec}$  is the carbon dioxide emission factor for fuel type (*i*) measured in kilograms of CO<sub>2</sub>-e per gigajoule.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-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

For section 2.42, the emission factor *EF<sub>i,CO2,ox,ec</sub>* from the combustion of fuel type (*i*) must allow for oxidation effects and must first estimate *EF<sub>i,co2,ox,kg</sub>* in accordance with the following formula:

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

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

Under Method 2, representative and unbiased samples of fuels consumed must be obtained for analysis. Analysis of the fuels for carbon, energy, ash or moisture content must be done in accordance with listed Australian or international standards.

A listing of applicable standards is given in Section 2.45. Examples of equivalent standards include those produced by AS, NZ, ASTM, ISO and CEN standards organisations. The standards must be in force on the date stated in section 1.9.

Unlike solid and gaseous fuels, standards for analysis have not been listed for a number of fuel types, reflecting the apparent absence of such standards particularly for volatile fuels. It is considered that for many liquid fuels that the use of Method 2 facility-specific emission factors would be likely to bring only marginal benefits in any case.

A NATA (National Association of Testing Authorities) accredited laboratory or similar laboratory complying with ISO 17025 should be used to conduct the analysis.

Minimum frequencies of analysis are also provided for in section 2.46.

#### 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)

Item	Fuel	Energy Content	Carbon	Density
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
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:	N/A	N/A	N/A
	(a) petroleum based oils and petroleum based greases mentioned in items 1 and 2			
	(b) the petroleum based products mentioned in items 3 to 18			
20	Biodiesel	N/A	N/A	N/A
21	Ethanol for use as a fuel in an	N/A	N/A	N/A

Item	Fuel	Energy Content	Carbon	Density
	internal combustion engine			
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

As for solid and gaseous fuels, Method 3 is a variation on Method 2. Method 3 provides for the same requirements of Method 2 except that sampling of fuels should also be conducted in accordance with listed Australian or international standards in section 2.47 or by an equivalent standard. Once sampling of the fuel has been conducted in accordance with the standard, the analysis of the fuel for carbon and other factors should be conducted as for Method 2. Emissions may then be estimated in accordance with Method 2.

# 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.

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

item	Liquid Fuel	Standard
6	Gasoline for use as fuel in an	ISO 3170:2004
	aircraft	ISO 3171:1988
		ASTM D 4057 – 06
		ASTM D 4177 – 95 (2005)
7	Kerosene (other than for use as	ISO 3170:2004
	fuel in an aircraft)	ISO 3171:1988
		ASTM D 4057 – 06
		ASTM D 4177 – 95 (2005)
8	Kerosene for use as fuel in an	ISO 3170:2004
	aircraft	ISO 3171:1988
		ASTM D 4057 – 06
		ASTM D 4177 – 95 (2005)
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:	ISO 3170:2004

item	Liquid Fuel	Standard
	(a) petroleum based oils and	ISO 3171:1988
	petroleum based greases mentioned in items 1 and 2; and	ASTM D 4057 – 06
	(b) the petroleum based products mentioned in items 3 to 18	
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	ISO 3170:2004
	mentioned in items 20 and 21	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

Method 2 for the estimation of methane and nitrous oxide emissions from the combustion of liquid fuels is very similar to Method 1 - however the Reporter uses an equipment-specific emission factor set out in Schedule 1 of the Determination. This approach is only available for post-2004 vehicles and certain trucks with specified engine designs.

No sampling and analysis of fuels are required for this Method 2 for non-carbon dioxide emissions. This is because the emissions of methane and nitrous oxide depend, in general, on combustion conditions and the equipment used to combust the fuel. In contrast, the carbon dioxide emissions depend on the chemical qualities of the fuels themselves which can only be ascertained by analysis.

# 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  $EF_{ijoxec}$  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.

# Table 2.4.5AFuel combustion — liquid fuels for<br/>transport energy purposes for post-2004<br/>vehicles

ltem	Fuel combusted	Energy content factor GJ/kL	Emission factor kg CO2-e/GJ (RELEVANT OXIDATION FACTORS INCORPORATED		actor GJ IDATION PORATED)
			CO <sub>2</sub>	CH₄	N <sub>2</sub> O
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

Notes on the sources of the factors listed above can be found at Appendix 2A.

## Table 2.4.5BFuel combustion — liquid fuels for

## transport energy purposes for certain

#### trucks

ltem	Fuel type	Heavy vehicles design standard	Energy content factor GJ/kL	Emission factor kg CO <sub>2</sub> -e/GJ (RELEVANT OXIDATION FACTORS INCORPORATED)		
				CO <sub>2</sub>	CH₄	N <sub>2</sub> O
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

Notes on the sources of the factors listed above can be found at Appendix 2A.

#### Example

A company consumes 35 000 kL (kilolitres) of diesel oil: 25 000 kL for transport purposes (with a post-2004 vehicle fleet) and 10 000 kL for stationary energy purposes. The Reporter elects to use Method 1 (*Division 2.4.2*) for each of the three greenhouse emission gases (*j*) (carbon dioxide, methane and nitrous oxide) for the diesel consumed for stationary energy purposes and Method 2 for methane and nitrous oxide emissions from diesel consumed for transport by post 2004 vehicles. Emissions are estimated as follows:

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

where:

 $E_{ij}$  is emissions of gas type (*j*) released from the combustion of fuel type (*i*) from the operation of the facility during the year measured in CO<sub>2</sub>-e tonnes.

 $Q_i$  is the quantity of the fuel type (i) combusted from the operation of the facility during the year measured in tonnes and estimated under Division 2.4.6. In this case 25 000 kL of diesel is used for transport purposes and 10 000kL of diesel is for stationary energy purposes.

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

- (a) for stationary energy purposes column 3 of the table 2.4.2A (Part 3 of Schedule 1 of the *Determination*). In this case being 38.6 GJ/kL.
- (b) for post-2004 vehicles column 3 of table 2.4.5A (Division 4.2 of Part 4 of Schedule 1 of the *Determination*). In this case being 38.6 GJ/kL.
- $EF_{oxij}$  is the emission factor for each gas type (*j*) released from the operation of the facility during the year (which includes the effect of a default oxidation factor) measured in kilograms CO<sub>2</sub>- e per gigajoule of the fuel type (*i*) according to source as mentioned in:
  - (a) for stationary energy purposes columns 4-6 of the table 2.4.2A (Part 3 of Schedule 1 of the *Determination*); and
  - (b) for post-2004 vehicles column 4-6 of table 2.4.5A (Division 4.2 of Part 4 of Schedule 1 of the *Determination*).

Therefore, emissions of greenhouse gases (carbon dioxide, methane and nitrous oxide) in tonnes of  $CO_2$ -e are estimated as follows:

Combustion of diesel oil for stationary energy purposes (Method 1): Emissions of carbon dioxide = (10 000 x 38.6 x 69.9)/1 000 = 26, 981 t CO<sub>2</sub>-e Emissions of methane = (10 000 x 38.6 x 0.1)/1 000 = 39 t CO<sub>2</sub>-e Emissions of nitrous oxide = (10 000 x 38.6 x 0.2)/1 000  $= 77 t CO_2-e$ Combustion of diesel oil for transport purposes for post-2004 vehicles: Emissions of carbon dioxide = (25 000 x 38.6 x 69.9)/1 000  $= 67,454 \text{ t CO}_2\text{-e}$ Emissions of methane (Method 2) = (25 000 x 38.6 x 0.01)/1 000  $= 10 t CO_2-e$ Emissions of nitrous oxide (Method 2) = (25 000 x 38.6 x 0.6)/1 000  $= 579 t CO_2-e$ 

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

This method applies to the consumption of petroleum based oils or greases (PBOGs) as lubricants or greases.

PBOGs that are consumed without combustion should be reported under section 2.68. Some scenarios to which section 2.68 of the Determination would apply include:

- coating of metal products with petroleum-based oils for corrosion protection;
- use of petroleum-based oils as hydraulic fluids (including brake fluids);
- greases used in electric motor applications;
- oils used in gearboxes;
- use of petroleum-based oils as components of products such as oil-extended polymers or elastomers, paints, solvents or sprays;
- use of oils in electrical equipment (e.g. transformer oil); and
- use of oils as heat transfer fluids or working fluids in industrial applications.

Depending on the operating conditions of the facility and the number and complexity of consumption points, reporters may wish to use the flash point of the fuel to identify whether or not the PBOG could be combusted. The flash point is the lowest temperature at which a product can form a vapour/air mixture capable of combustion. It is a measurable and testable physical property of all petroleum-based products and is stated on the Material Safety Data Sheet of every PBOG product sold.

By comparing the maximum operating temperature that each PBOG is likely to be exposed, it is possible to show that a given PBOG is appropriately reported as consumed without combustion.

# 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:

 $E_{pogco2}$  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<sub>2</sub>-e tonnes.

 $Q_{pog}$  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.

 $EC_{pogco2}$  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.

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

- (2) **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<sub>2</sub>-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:

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

 $EF_{pogco2ec}$  is 69.9.

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

$$OF_{pog} = \frac{Q_{pog} - Oil Transferred Offsite_{pog}}{Q_{pog}}$$

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.

*Oil Transferred Offsite*<sub>pog</sub> 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.

The quantity of consumption of each of the fuel types specified in the Regulations, Schedule 1, are to be estimated according to one of the criterion set out below.

The fuel types listed principally reflect the lists of fuels currently used by the Bureau of Resources and Energy Economics (BREE) to prepare Australia's Energy Statistics and report, inter alia, on behalf of the Australian Government to the International Energy Agency.

Separate estimates of the quantities of each fuel type consumed for the purpose of making electricity; for use as reductants or feedstocks; for use in transport (excluding international bunker fuels) and other stationary energy are required.

The quantities of fuels consumed for transport should exclude those quantities consumed for international transport purposes, if any, to reflect international reporting requirements for the national inventory. It is intended that this may be achieved by excluding international bunker fuels as defined in National Greenhouse and Energy Reporting Regulations 2008, Regulation 1.03, and that the point of differentiation between domestic and international consumption will be identical to that provided by the *Customs Act 1901* which is used also for excise and GST purposes.

Biogenic carbon fuels attract a zero carbon dioxide emission factor to ensure that the reporting system aligns with the reporting requirements of the IPCC reporting guidelines for national inventories and the practice, for example, of the EU for its Emissions Trading System. Non-carbon dioxide emissions from the combustion of biogenic fuels must be reported, however.

Division 2.4.6 specifies the criteria for the estimation of the amounts of liquid fuels combusted from the operation of a facility during a year. There are four criteria available for the estimation of quantities combusted. Under the National Greenhouse and Energy Reporting Regulations 2008, the criterion chosen will need to be reported.

The criteria include:

(a) Criterion A - the amount of the fuel delivered for the facility during the year as evidenced by invoices or delivery records issued by the vendor of the fuel (2.50);

(b) Criterion AA - indirect measurement at the point of consumption - based on the amount of fuel delivered for the facility and adjusted for changes in stocks (2.51);

(c) Criterion AAA - direct measurement at the point of consumption - based on the amount of fuel combusted as estimated by measurement equipment that comply with specified standards (2.52);

(d) Criterion BBB - simplified measurement of consumption (2.53).

Measuring equipment calibrated to a measurement requirement in Section 2.52 refers to the standards required for measurement to support excise taxation arrangements.

In Section 2.52 it is intended that measured data for fuels delivered would also meet the Criterion AAA under certain circumstances. These circumstances are that stocks of the fuel consumed at the facility are less than 5% of fuel consumption for the facility during the year and that the stock changes by less than 1% during the year.

The simplified measurement of consumption criterion is available in those cases where the Reporter does not purchase fuel and where the Reporter does not have metering equipment installed that meets the requirements of criterion AAA. In these cases, it is intended that Reporters should estimate consumption using metering devices or measurement techniques in practice in the industry. Such measurements would need to meet the criteria set out 1.13 of transparency, comparability, accuracy and completeness. These data would be classified and reported as BBB criterion data.

The restriction on the choice of criteria at 2.50 (3) is designed to ensure time series consistency of the measurements.

#### 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:

nere.

 $\Sigma_i$  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 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:

 $\Sigma_p$  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:

$$\Sigma_{\rm r} \rm CCF_{\rm r} \times Y_{\rm r}$$

where:

 $\Sigma_r$  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:

 $\Sigma_{i} \ \textbf{CCF}_{i} \times \Delta \textbf{S}_{qi} + \Sigma_{p} \ \textbf{CCF}_{p} \times \Delta \textbf{S}_{ap} + \Sigma_{r} \ \textbf{CCF}_{r} \times \Delta \textbf{S}_{yr}$ 

where:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

 $CCF_r$  has the same meaning as in step 3.

 $\Delta S_{yr}$  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<sub>2</sub>-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:

$$\Sigma_{i} \ \text{CCF}_{i} \ \times \Delta S_{qi} + \Sigma_{p} \ \text{CCF}_{p} \ \times \Delta S_{ap} + \Sigma_{r} \ \text{CCF}_{r} \ \times \Delta S_{yr} + \alpha \ \gamma \text{RCCS}_{co_{2}}$$

where:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

 $CCF_r$  has the same meaning as in step 3.

 $\Delta S_{yr}$  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.

 $\alpha$  is the factor <sup>3.664</sup> for converting the mass of carbon dioxide to a mass of carbon.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-e tonnes.

 $RCCS_{CO_2}$  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.

#### Estimating emissions from standalone coke production using method 1

An example for estimating emissions from a standalone coke production facility using the method 1 carbon mass balance approach is provided below. The example uses coking coal and fuel oil to produce coke. The facility also produces coal tar and waste in the form of un-oxidised carbon, in addition to experiencing stock changes during the year. The relevant data for the coke production facility is outlines in the table below:

Fuel or product type	Fuels delivered during the year	Products produced and leaving the activity during the year	Change (increase) in stocks during the year	Carbon content factor (CCF)
Coke oven coke		9,000 tonnes	-300 tonnes	0.789
Coking coal	14,500 tonnes		500 tonnes	0.752
Fuel oil	100 kilolitres			0.797
Coal tar		400 tonnes	20 tonnes	0.837

Step 1 Calculate the carbon content in fuel types (i) or carbonaceous input material delivered for the activity during the year measured in tonnes of carbon as follows:

Where:  $\Sigma_i CCF_i \times Q_i$ 

 $CCF_i$  is the carbon content factor mentioned in Appendix A 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.

The Method 1 default carbon content factors can be found in Schedule 3 of the NGER (Measurement) Determination and are shown in the table above.

 $Q_i$  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 Division 2.2.5, 2.3.6 and 2.4.6. In this case the quantities of input materials are shown in the table above:

#### To calculate the carbon content for the input materials:

Carbon content of coking  $coal = (14,500 \times 0.752) = 10,904$  tonnes of carbon

Carbon content of fuel oil =  $(100 \times 0.797) = 79.7$  tonnes of carbon

#### **Therefore, total carbon** = (10,904 + 79.7) **= 10,983.7 tonnes**

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

Where:

### $\Sigma_p \operatorname{CCF}_p \times A_p$

 $CCF_p$  is the carbon content factor measured in tonnes of carbon for each tonne of product type (p) produced during the year. In this case the carbon content factor of each product type is shown in the table above:

 $A_p$  is the quantity of product types (p) produced leaving the activity during the year measured in tonnes. In this case the quantity of products are shown in the table above:

To calculate the carbon content for the products leaving the activity during the year:

Carbon content of coke oven  $coke = (9,000 \times 0.789) = 7,101$  tonnes of carbon

Carbon content of coal tar =  $(400 \times 0.837) = 334.8$  tonnes of carbon

#### **Therefore, total carbon** = (7,101 + 334.8) = **7435.8 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:

Where:

## $\Sigma_r \operatorname{CCFr} \times \operatorname{Yr}$

 $CCF_r$  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. In this case the quantities of waste by-products are non-oxidised carbon, estimated in accordance with the NGER (Measurement) Determination as being 100 tonnes.

To calculate the carbon content for the waste products leaving the activity during the year:

Carbon content of non-oxidised carbon = 100 tonnes of carbon

Therefore, total carbon = 100 tonnes

Step 4 Calculate the carbon content in the amount of the increase in stocks of inputs, products and waste by products held within the boundary of the activity during the year in tonnes of carbon as follows:

Where:

$$\Sigma_{i} \operatorname{CCF_{i}} \times \Delta S_{qi} + \Sigma_{p} \operatorname{CCF_{p}} \times \Delta S_{ap} + \Sigma_{r} \operatorname{CCF_{r}} \times \Delta S_{yr}$$

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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. In this case the quantities of increases in stocks are shown in the table above:

#### To calculate the carbon content for increase of fuel types

Carbon content of coking  $coal = (500 \times 0.752) = 376$  tonnes of carbon

#### Therefore, total carbon = 376 tonnes

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  is the increase in stocks of product types (p) produced by the activity and held within the boundary of the activity during the year measured in tonnes. In this case the quantities of product types shown in the table above:

#### To calculate the carbon content for increase in stock of product type:

Carbon content of coal tar =  $(20 \times 0.837) = 16.74$  tonnes of carbon

Carbon content of coke oven  $coke = (-300 \times 0.789) = -236.7$  tonnes of carbon

#### **Therefore, total carbon** = (16.74 + -236.7) = -219.96 tonnes

*CCF<sup><i>r*</sup> has the same meaning as in step 3.

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

There was no change in waste product stock produced and held during the year.

To calculate the total carbon contained in the change of stock:

Carbon content of increase in fuel types = 376 tonnes

Carbon content of increase in product types = -219.96 tonnes

Carbon content of increase in waste by-products = 0 tonnes

**Therefore, total carbon** = (376 + -219.6 + 0) = **156.04 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);

In this case A is:

=7435.8 + 100 + 156.04

= 7,691.84 tonnes of carbon

(b) subtract amount A from the amount worked out under step 1 to work out a new amount (amount B);

In this case:

$$= 10,983.7 - 7,691.84$$

= 3,291.86 tonnes of carbon

(c) multiply amount B by 3.664 to work out the amount of emissions released from the operation of the activity during a year.

= 3,291.86 x 3.664

= 12,061.37504 tonnes CO<sub>2</sub>-e

Therefore, total carbon balance CO<sub>2</sub> emissions from the source = 12,061 tonnes

## **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

- 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:

 $\Sigma_i$  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:

$$\Sigma_p \operatorname{CCF}_p \times A_p$$
where:

 $\Sigma_p$  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:

 $\Sigma_r \operatorname{CCFr} \times \operatorname{Yr}$ 

where:

 $\Sigma_r$  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:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

 $CCF_r$  has the same meaning as in step 3.

 $\Delta S_{yr}$  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.

- 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:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

*CCF*<sub>r</sub> has the same meaning as in step  $3 \varDelta S_{yr}$  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.

 $\alpha$  is the factor <sup>3.664</sup> for converting the mass of carbon dioxide to a mass of carbon.

 $\gamma$  is the factor 1.861 x 10<sup>-3</sup> for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-e tonnes.

*RCCS<sub>co2</sub>* 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:

 $\sum_{i} CCF_{i} \times \Delta S_{qi} + \sum_{p} CCF_{p} \times \Delta S_{ap} + \sum_{r} CCF_{r} \times \Delta S_{yr} + \alpha \gamma RCCS_{co_{2}}$ 

where:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

 $CCF_r$  has the same meaning as in step 3.

 $\Delta S_{yr}$  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.

 $\alpha$  is the factor <sup>3.664</sup> for converting the mass of carbon dioxide to a mass of carbon.

 $\gamma$  is the factor 1.861 x 10<sup>-3</sup> for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-e tonnes.

 $RCCS_{CO_2}$  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.

These standards include the following approaches to quantification:

Manual sorting (CEN/TS 15440:2006)

The manual sorting technique involves a sample of the solid blended fuel being sorted by hand into sub-fractions of biomass and non-biomass matter.

This procedure however is limited to fuels with a minimum particle size greater than 1 cm and only applies to blends of solid fuels.

#### Selective dissolution (CEN/TS 15440:2006)

The selective dissolution method for the determination of the biomass content involves the treatment of a sample of blended solid fuel with concentrated sulphuric acid topped with hydrogen peroxide. The biomass in the solid recovered fuel will selectively dissolve and the non-biomass will remain in the residue.

This technique is not applicable to the following blended fuels:

- charcoal, peat and solid fossil fuels like hard coal, coke, brown coal and lignite and to mixtures of these and solid recovered fuels;
- solid recovered fuels that contain more than 10 % of natural and/or synthetic rubber residues;
- solid recovered fuels that contain a combination of more than 5 % by weight of:
  - o nylon, polyurethane or other polymers containing molecular amino groups;
  - o biodegradable plastics of fossil origin;
- solid recovered fuels that contain a combination of more than 5 % by weight of:
  - wool or viscose;
  - o non-biodegradable plastics of biogenic origin;
  - o oil or fat present as a constituent of biomass.

#### Radiocarbon Analysis

The ASTM D 6866-08 standard also provides for a radiocarbon analysis method. The standard describes techniques for determining the biogenic content of solid, liquid and gaseous samples using radiocarbon analysis. The basic premise is that Carbon-14 (<sup>14</sup>C), a radioactive isotope of carbon, has a half life of 5,730 years once it is no longer part of a living organism. This means that no <sup>14</sup>C will remain in fossil fuels because it has completely decayed, whereas in recent biomass, such as wood, a portion of <sup>14</sup>C still remains.

In effect, it is argued that biogenic matter contains a well characterized amount of carbon-14 that is easily distinguished from other materials such as fossil fuels that do not contain any carbon-14. Since the amount of carbon-14 in biomass is well known, a percentage of biogenic carbon can be calculated easily from the overall carbon atoms in the sample.

This technique may be applied to any type of blended fuel including gaseous, liquid and solid fuels. The technique may be used to analyse the fuels directly or can be used to analyse the combustion gases once the fuel has being burned. The latter technique may be useful where direct emissions monitoring systems are already in place to measure  $CO_2$  emissions and where sampling fuels can be difficult.

# 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 with a maximum capacity to produce less than 0.5 megawatts of electricity—100 000 kilowatt hours; or
  - (v) for all other electricity consumption—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.

#### Examples of non-combustive use of fuels

- When used directly in a non-fuel manner for example, fuels used directly as a solvent or a flocculent;
- When used as an ingredient in the manufacture of short-life products such as paints, cleaning agents and explosives manufactured for sale;
- When packaged for non-internal combustion engine use (restricted to containers less than 20 litres and kerosene, mineral turpentine, white spirit, liquid aromatic

hydrocarbons and other petroleum products as defined in 10.28 of the schedule to the Excise Tariff Act);

- When blended with other products and then packaged for non-internal combustion engine use;
- When unprocessed natural gas is consumed to create natural gas distributed in a pipeline.
- Some uses of petroleum based oils and greases. Division 2.4.5A provides more guidance on the reporting of petroleum based oils and greases.

Note the reporting thresholds in 2.68 apply to each fuel type individually. For example, where a facility consumes 10 kL of diesel and 10 kL of solvents for non-combustion purposes this facility is not required to report under this provision.

# 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

Cogeneration processes are situations where two products – electricity and another product – are produced from the consumption of a single quantity of fuel.

This section specifies that for the purpose of complying with the *National Greenhouse and Energy Reporting Regulations 2008*, subregulation 4.23 (3), the quantity of fuel consumed and allocated to the production of electricity should be estimated using the efficiency method as described in the Allocation of Emissions from a Combined Heat and Power (CHP) Plant Guide to calculation worksheets (September 2006) v1.0 (the cogeneration guide) issued by World Resource Institute and World Business Council for Sustainable Development unless the heat is to be used for producing mechanical work when the work potential method described in the cogeneration guide may be used.

The efficiency method is the preferred method of the World Resource Institute and World Business Council for Sustainable Development. Limiting the approaches that can be used provides for more consistent interpretation of reported data and establishes well-understood boundaries for all data reported.

- (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

Apportionment of fuels consumed between various purposes is considered to be less critical than the overall estimate of fuel consumed for a facility. Consequently, allocations of fuels consumed between purposes may be determined by facility records based on facility measurement techniques.

For the purpose of determining fuels consumed in transport, road transport means fuel consumed by a vehicle registered for road use.

Subject to section 2.70, the amount of fuel type (i) consumed by a reporting corporation or liable entity 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 liable entity if the records are based on the measurement equipment used by the corporation or the liable entity to measure consumption of the fuel types.

# Appendix 2A Notes on Energy and Emission Factors

The following notes apply to energy content and emission factors in the following tables:

- Table 2.2.2
- Table 2.3.2
- Table 2.4.2A
- Table 2.4.2B
- Table 2.4.5A
- Table 2.4.5B

 Energy value: Source – DCCEE analysis of NGER reporting data for reporting years 2008-09 to 2010-11 and industry advice. CO<sub>2</sub> emission factor: Source - National Inventory Report 2006, Department of Climate Change. . Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency and Energy Efficiency.

1A. Energy value: Source – DCCEE analysis of NGER reporting data for reporting years 2008-09 to 2010-11 and industry advice. CO<sub>2</sub> emission factor: Source - National Inventory Report 2006, Department of Climate Change. . Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency and Energy Efficiency.

1B. Energy value: Source – DCCEE analysis of NGER reporting data for reporting years 2008-09 to 2010-11 and industry advice. CO<sub>2</sub> emission factor: Source - National Inventory Report 2006, Department of Climate Change. . Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency and Energy Efficiency.

 Energy value: Source – AGEIS database, Department of Climate Change and Energy Efficiency (based on facility reports). CO<sub>2</sub> emission factor: Source - AGEIS database, Department of Climate Change and Energy Efficiency (based on facility reports). Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency.

 Energy value: Source – ABARE<sub>1</sub> (washed coking). CO<sub>2</sub> emission factor: Source - National Inventory Report 2006, Department of Climate Change. . Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency. Energy value: Source – ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source - AGEIS database, Department of Climate Change and Energy Efficiency (based on facility reports).
 Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency.

Energy value: Source – ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source – National Inventory Report
 2006, Department of Climate Change. Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of
 Climate Change and Energy Efficiency.

Energy value: Source – ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source – National Inventory Report
 2006, Department of Climate Change (coal tar). Non-CO2 factors: Source: AGEIS database,
 Department of Climate Change and Energy Efficiency.

7. See (4)

Energy value: Source – GHD Review of Sectoral Models, Internal report to the AGO, 2006.
 CO<sub>2</sub> emission factor: Source – National Inventory Report 2006, Department of Climate Change.
 Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency.

Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. CO<sub>2</sub> emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.
 Non-CO<sub>2</sub> factors: Source: IPCC 2006. Derived using conversion factor of 0.95.

Energy value: Source: ABARE<sub>1</sub> (dry wood). Non-CO<sub>2</sub> factors: Source: AGEIS database,
 Department of Climate Change and Energy Efficiency.

11. Energy value: Source: ABARE<sub>1</sub> (green wood). Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency.

12. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. Non-CO<sub>2</sub> factors: Source: IPCC 2006. Derived using conversion factor of 0.95.

13. Energy value: Source: ABARE<sub>1</sub>. Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency.

Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. Non-CO<sub>2</sub> factors: Source: IPCC 2006. Derived using conversion factor of 0.95.

15. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. Non-CO<sub>2</sub> factors: Source: IPCC 2006. Derived using conversion factor of 0.95.

16. See (14)

17. Energy value: Source: ABARE<sub>1</sub> (weighted average). CO<sub>2</sub> emission factor: Source - AGEIS database, Department of Climate Change and Energy Efficiency. Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency.

Energy value: Source: ABARE<sub>1</sub> (coal seam methane). CO<sub>2</sub> emission factor: Source - AGEIS database, Department of Climate Change and Energy Efficiency. Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency.

19. Energy value: Source: ABARE<sub>1</sub> (coal seam methane). CO<sub>2</sub> emission factor: Source - AGEIS database, Department of Climate Change and Energy Efficiency. Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency.

20. See (17)

21. See (17)

22. Energy value: Source: ABARE<sub>1</sub> (weighted average). CO<sub>2</sub> emission factor: Source – National Inventory Report 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency.

Energy value: Source: ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source – National Inventory Report
 2006, Department of Climate Change. Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of
 Climate Change and Energy Efficiency.

24. Energy value: Source – ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source: IPCC 2006. Derived using conversion factor of 0.90. Non-CO<sub>2</sub> factors: Source: IPCC 2006. Derived using conversion factor of 0.90.

25. Energy value: Source – ABARE<sub>2</sub> (synthetic natural gas). CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: Source: AGEIS database.

26. Energy value: Source – ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source - AGEIS database,
 Department of Climate Change and Energy Efficiency. Non-CO<sub>2</sub> factors: Source: AGEIS database,
 Department of Climate Change and Energy Efficiency.

27. See (17)

28. Energy value: Source – ABARE<sub>1</sub>. Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency.

29. Energy value: Source – ABARE<sub>1</sub>. Non-CO<sub>2</sub> factors: Source: AGEIS database, Department of Climate Change and Energy Efficiency.

30. See (28)

 Energy value: Source – ABARE<sub>2</sub> (lubricants and greases). CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change (lubricants). Oxidation factor 0.2. Non-CO<sub>2</sub> factors: nil.

32. Energy value: Source – ABARE<sub>2</sub> (lubricants and greases). CO<sub>2</sub> emission factor: Source:
 National Inventory Report 2006, Department of Climate Change (lubricants). Oxidation factor 0.2.
 Non-CO<sub>2</sub> factors: nil.

33. Energy value: Source – ABARE<sub>2</sub> (weighted average). CO<sub>2</sub> emission factor: Source: IPCC
 2006. Derived using conversion factor of 0.95. Non-CO<sub>2</sub> factors: IPCC 2006 (Energy Industries).
 Derived using conversion factor of 0.95.

Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. CO<sub>2</sub> emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95. Non-CO<sub>2</sub> factors: IPCC 2006 (Energy Industries). Derived using conversion factor of 0.95.

Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate
 Change and Energy Efficiency.

36. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change. Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate
 Change and Energy Efficiency.

37. Energy value: Source – ABARE<sub>2</sub> (power kerosene). CO<sub>2</sub> emission factor: Source: National
 Inventory Report 2006, Department of Climate Change. Non-CO<sub>2</sub> factors: AGEIS database,
 Department of Climate Change and Energy Efficiency.

Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate
 Change and Energy Efficiency.

Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate
 Change and Energy Efficiency.

40. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source National Inventory Report
 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate
 Change and Energy Efficiency.

 Energy value: Source – ABARE<sub>2</sub> (low sulphur). CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change. Derived using conversion factor of 0.95.
 Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate Change and Energy Efficiency.

42. Energy value: Source – ABARE<sub>2</sub>. Given same energy content as solvents. CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change (assumed same as solvents).. Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate Change and Energy Efficiency.

43. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: National Inventory Report 2006, Department of Climate Change. Derived using conversion factor of 0.95.. Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate Change and Energy Efficiency. 44. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate
 Change and Energy Efficiency.

Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate
 Change and Energy Efficiency.

46. Energy value: Source – IPCC 2006. CO<sub>2</sub> emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.. Non-CO<sub>2</sub> factors: IPCC 2006, Manufacturing category. Derived using conversion factor 0.95.

47. Energy value: Source – ABARE<sub>1</sub> (refinery fuel). CO<sub>2</sub> emission factor: Source: IPCC 2006.
 Derived using conversion factor of 0.95.. Non-CO<sub>2</sub> factors: IPCC 2006. Derived using conversion factor 0.95.

48. See (46)

49. Energy value: Source – ABARE<sub>2</sub>. Based on IPCC 2006, given same energy content as solvents. CO<sub>2</sub> emission factor: Source National Inventory Report 2006, Department of Climate Change (set same as solvents). Oxidation factor 0.99. Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate Change and Energy Efficiency.

Energy value: Source – Derived from US Department of Energy. Non-CO<sub>2</sub> factors: IPCC
 2006. Derived using conversion factor 0.95.

51. Energy value: Source – ABARE<sub>2</sub>. Non-CO<sub>2</sub> factors: IPCC 2006. Derived using conversion factor 0.95.

52. See (51).

53. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: AGEIS database Department of Climate
 Change and Energy Efficiency.

54. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: AGEIS database Department of Climate
 Change and Energy Efficiency.

55. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate
 Change and Energy Efficiency.

56. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: AGEIS database Department of Climate
 Change and Energy Efficiency.

57. Energy value: Source – ABARE<sub>2</sub> (low sulphur). CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change. Derived using conversion factor of 0.95. . Non-CO<sub>2</sub> factors: AGEIS database Department of Climate Change and Energy Efficiency.

58. Energy value: Source – Derived from ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: AGEIS database Department of Climate Change and Energy Efficiency.

59. Energy value: Source – Derived from US Department of Energy, 2006. Non-CO<sub>2</sub> factors: IPCC 2006. Derived using conversion factor 0.95.

60. Energy value: Source – ABARE<sub>2</sub>. Non-CO<sub>2</sub> factors: IPCC 2006. Derived using conversion factor 0.95.

61. See (60)

62. Energy value: Source: ABARE<sub>1</sub> (weighted average). CO<sub>2</sub> emission factor: Source - AGEIS database, Department of Climate Change and Energy Efficiency. Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate Change and Energy Efficiency.

63. Energy value: Source: ABARE<sub>1</sub> (weighted average). CO<sub>2</sub> emission factor: Source - AGEIS database, Department of Climate Change and Energy Efficiency. Non-CO<sub>2</sub> factors: AGEIS database, Department of Climate Change and Energy Efficiency.

63A Energy value: Source – ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source - AGEIS database,
 Department of Climate Change and Energy Efficiency. Non-CO<sub>2</sub> factors: Source: AGEIS database,
 Department of Climate Change and Energy Efficiency

Energy value: Source – ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source - AGEIS database,
 Department of Climate Change and Energy Efficiency. Non-CO<sub>2</sub> factors: Source: AGEIS database,
 Department of Climate Change and Energy Efficiency

64. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: Derived from AGEIS database, Department of Climate Change and Energy Efficiency.

65. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: Derived from AGEIS database, Department
of Climate Change and Energy Efficiency.

66. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: Derived from AGEIS database, Department
 of Climate Change and Energy Efficiency.

67. Energy value: Source – ABARE<sub>2</sub>. Non-CO<sub>2</sub> factors: Derived from AGEIS database, Department of Climate Change and Energy Efficiency.

Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: Derived from AGEIS database, Department of Climate Change and Energy Efficiency.

69. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source National Inventory Report
2006, Department of Climate Change. Non-CO<sub>2</sub> factors: Derived from AGEIS database, Department
of Climate Change and Energy Efficiency.

70. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source National Inventory Report
 2006, Department of Climate Change.. Non-CO<sub>2</sub> factors: Derived from AGEIS database, Department
 of Climate Change and Energy Efficiency.

# **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**

The principal sources of fugitive greenhouse gases from coal mining include emissions from underground and open cut mining activities and emissions from decommissioned mines. A small amount of emissions are also associated with flaring coal mine waste gas and post-mining activities such as from the stockpiling of coal. This chapter describes the methods for estimating emissions from each of these sources.

Other sources of emissions arising from the coal production process, such as from the combustion of fuels for energy (e.g. electricity production), are not described in this chapter and must be estimated using the Methods described in other chapters.

## 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

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

## **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.

Summary of available methods, for estimating emissions from underground mines, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O		
Underground mining activities					
Method 1	NA	NA	NO		
Method 2, 3	NA	NA	NO		
Method 4	Section 3.6	Section 3.6	NO		
Post-mining Activities					
Method 1	NA	Section 3.17	NO		
Methods 2, 3 and 4	NA	NA	NO		
Flaring					
Method 1	Section 3.14	Section 3.14	Section 3.14		
Method 2	Section 3.15	Section 3.15A	Section 3.15A		
Method 3	Section 3.16	NA	NA		
Method 4	NA	NA	NA		
Venting					
Methods 1, 2 and 3	NA	NA	NO		
Method 4	Part 1.3	Part 1.3	NO		

NA = Not available. NO = Not occurring

# 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<sub>2</sub>-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<sub>2</sub>-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

Method 4 for estimating emissions associated with underground mining operations involves directly measuring emissions within ventilation shafts and degasification systems. This Method is dealt with in detail in Part 1.3 of Chapter 1.

Estimation methods under current applicable state or territory legislation

In addition to the methods outlined in Part 1.3, Reporters may also directly measure emissions using periodic emissions measurement (PEM) in accordance with elements of relevant State Government legislation. This legislation includes the following:

*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).

It is intended that, as a minimum, existing practices for the monitoring of gases at underground mines may be maintained as input into the emissions estimation process under Method 4.

(1) For subsections 3.4(2) and (3), method 4 is:

$$\mathbf{E}_{j} = \mathbf{CO}_{2 \cdot \mathbf{e}_{j \text{ gen, total}}} - \gamma_{j} \left( \mathbf{Q}_{ij, cap} + \mathbf{Q}_{ij, flared} + \mathbf{Q}_{ijtr} \right)$$

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<sub>2</sub>-e tonnes.

 $CO_{2}$ - $e_{jgen, total}$  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<sub>2</sub>-e tonnes and estimated using the direct measurement of emissions in accordance with subsection (2).

 $\gamma_j$  is the factor for converting a quantity of gas type (*j*) from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-e tonnes, being:

- (a) for methane— $6.784 \times 10^{-4} \times 25$ ; and
- (b) for carbon dioxide— $1.861 \times 10^{-3}$ .

 $Q_{ij,cap}$  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.

#### Emissions from diesel combustion emissions and the ambient CO2 in air

When estimating fugitive emissions from underground mine, it is important be mindful that Ej in paragraph (1) above represents the **fugitive** emissions that result from the

extraction of coal from the mine. Volumetric flow within underground coal mine ventilation systems may also include gases that arise from sources other than fugitive emissions such as;

- fuel combustion diesel emissions arising from the use of machinery, while the machinery is in the underground mine, and
- ambient carbon dioxide present in the air that was drawn into the mine ventilation intake.

To ensure accurate emission estimation it may be necessary to make a deduction of these non-fugitive source gasses from the gas volumes measured in mine ventilation systems.

The Determination provides methods for estimating fuel combustion emissions from diesel under Part 2.4, however no specific guidance is given on avoiding any double counting of those emissions entrained in mine ventilation measurements. To ensure accuracy, fuel combustion emissions arising from the use of machinery in the underground mine should be deducted from mine ventilation volumes.

Any deductions of fuel combustion emissions arising from the use of machinery in the underground mine must be done in accordance with the general principles in 1.13 of the Determination.

The Determination also provides no specific guidance on the deduction of ambient carbon dioxide from mine ventilation air. However, as in the case above for diesel combustion emissions, the estimation must be done in accordance with the general principles in 1.13 of the Determination.

## 3.7 Estimation of emissions

This section describes how measurements of gas flow rates and concentrations are converted from volumetric flow rates to mass emission estimates.

(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<sub>2</sub>-e tonnes.
- (3) The average mass emission rate for gas type (j) measured in CO<sub>2</sub>–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.

### **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

Method 1 describes how to estimate greenhouse gas emissions from the flaring of coal mine waste gas - by multiplying the quantity of coal mine waste gas flared by the energy content and emission factor for each gas type. The quantity of coal mine waste gas flared is estimated in accordance with Division 2.3.6. The energy content and emission factors are obtained from Division 2.3.2 in Chapter 2.

For subparagraph 3.4(4)(a)(i) and paragraphs 3.4(4)(b) and (c), method 1 is:

Note: Appropriate standards include USEPA—Method 3C—Determination of carbon dioxide, methane, nitrogen and oxygen from stationary sources (1996).

$$E_{\rm (fl)ij} = \ \frac{Q_{i,\rm flared}\ \times\ EC_i\ \times\ EF_{ij}}{1000}\ \times\ OF_{ii}$$

where:

 $E_{(f)ij}$  is the emissions of gas type (*j*) released from coal mine waste gas (*i*) flared from the mine during the year, measured in CO<sub>2</sub>-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<sub>2</sub>-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

Method 2 requires representative and unbiased samples of coal mine waste gas consumed and the analysis of the coal mine waste gas to determine gas composition. The methane and carbon dioxide content should be analysed and accounted for independently in accordance with Australian or equivalent international standards. The quantity of methane determined within the coal mine waste gas stream to be flared is applied to Section 3.15 to estimate carbon dioxide emissions and Section 3.15A to estimate methane and nitrous oxide emissions.

For subparagraph 3.4(4)(a)(ii), method 2 is:

$$\mathbf{E}_{_{ico_{2}}} = \frac{\mathbf{Q}_{_{k}} \times \mathbf{EC}_{_{i}} \times \mathbf{EF}_{_{k}}}{1000} \times \mathbf{OF}_{_{i}} + \mathbf{QCO}_{2}$$

where:

 $E_{iCO_2}$  is the emissions of CO<sub>2</sub> released from coal mine waste gas (*i*) flared from the mine during the year, measured in CO<sub>2</sub>-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<sub>2</sub>-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<sub>2</sub>-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<sub>2</sub>-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<sub>2</sub>-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

- Method 3 is the same as for Method 2 except that it requires samples to be obtained in accordance with Australian or equivalent international standards.
  - (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  $EF_k$  must be determined in accordance with the procedure for determining  $EF_{iCO_2oxec}$  in Division 2.3.4.

# Estimating Carbon dioxide emissions from Coal mine waste gas flaring using Method 2

Coal mining operations often involve the flaring of coal mine waste gas. In this example a facility flares a coal mine waste gas stream from pre-drainage activities of 1,000,000 cubic meters (at standard pressure and temperature) during the year. The gas stream is predominantly methane, but also contains some carbon dioxide and nitrogen. The reporters have chosen to use method 2 to estimate emissions as this approach provides the opportunity to develop a carbon dioxide emission factor that better reflects the methane present in the gas stream, as well as account for the in-situ carbon dioxide quantity which is emitted, but not combusted in the flare. The relevant data for the flaring of coal mine waste gas are as follows in the table below:

Data inputs for carbon dioxide emissions from coal mine waste gas flaring example.

Quantity of coal mine waste gas flared (at standard pressure and temperature) (cubic metres)	Component gas type of coal mine waste gas	gas type's share of the total coal mine waste gas volume (%)	gas type's volume (cubic metres)
1,000,000			
	Methane	91	910,000
	Carbon dioxide	7	70,000
	Nitrogen	2	20,000

Calculate the carbon dioxide emissions using Method 2 in section 3.15 of NGER (Measurement) Determination

$$\mathbf{E}_{_{ico_{2}}} = \frac{\mathbf{Q}_{_{\mathbf{k}}} \times \mathbf{E}\mathbf{C}_{_{\mathbf{i}}} \times \mathbf{E}\mathbf{F}_{_{\mathbf{k}}}}{1000} \times \mathbf{O}\mathbf{F}_{_{\mathbf{i}}} + \mathbf{Q}\mathbf{C}\mathbf{O}_{_{2}}$$

Where:

•

 $EiCO_2$  is the emissions of CO2 released from coal mine waste gas (i) flared from the mine during the year, measured in CO2-e tonnes.

Qk is the quantity of methane (k) within the coal mine waste gas from the mine during the year, measured in cubic metres in accordance with Division 2.3.3.

• This was determined by gas composition analysis of the coal mine waste gas (in accordance with Division 2.3.3)

• The average methane composition of the coal mine waste gas being flared during the year was estimated to be 91%.

Therefore, to calculate the volume of methane within the coal mine waste gas:

Coal mine waste gas volume = 1,000,000 Methane composition = 91% Total volume of methane (Qk) = 1,000,000 x 91/100 = 910,000 m3

 $QCO_2$  is the quantity of carbon dioxide within the coal mine waste gas emitted from the mine during the year, measured in CO2-e tonnes in accordance with Division 2.3.3.

This was also determined by gas composition analysis of the coal mine waste gas(in accordance with Division 2.3.3).

The average carbon dioxide composition of the coal mine waste gas being flared during the year was 7%.

Therefore, to calculate the volume of carbon dioxide within the coal mine waste gas:

Coal mine waste gas volume = 1,000,000

Carbon dioxide composition = 7%

Total volume of carbon dioxide = 1,000,000 x 7/100 = 70,000 m3

Carbon dioxide m3 to tonnes conversion factor at standard pressure and temperature (see Determination Section 3.21) =  $1.861 \times 10-3$ 

Therefore:

QCO2 = 70,000 x 1.861 x 10-3

QCO2 = 130.27 tonnes of carbon dioxide

EFj is the emission factor for carbon dioxide resulting from the flaring of the methane component (j) within the coal mine waste gas from the mine during the year, measured in kilograms of CO2-e per gigajoule..

This is determined using Section 2.22, where in;

Section 2.22 (1) the mol% will be 100% methane as the EF is specifically for methane only, and

o Section2.22 (4) the carbon dioxide emission factor for the flared methane has been converted to kilograms of CO2-e per gigajoule, using:

The energy content of coal mine waste gas mentioned in item 19 of Schedule 1 of the Determination.

The density of methane as calculated using its molecular weight in Section 2.22 (2)

• In this example it was estimated that the carbon dioxide emission factor for the methane within the coal mine waste gas = 49.12525 kg CO2-e/GJ

ECi is the energy content factor of methane within the coal mine waste gas (i), taken to be equivalent to item 19 of Schedule 1 of the Determination, measured in gigajoules per cubic metre.

• In this example the energy content for coal mine waste gas in Schedule 1 of the NGER (Measurement) Determination =  $37.7 \times 10-3 \text{ GJ/m3}$ 

OFi = 0.98, which is the flaring efficiency factor of coal mine waste gas (i) flared.

Therefore, to calculate the CO2 emissions from coal mine waste gas flared:

Qj = 910,000 m3 of methane

ECi =37.7 x 10-3 GJ/m3

EFj = 49.12525 kg CO2-e/GJ

OFi = 0.98

QCO2 = 130.27 tonnes of carbon dioxide

= ((910,000 x 37.7 x 10-3 x 49.12525)/1000 x 0.98) + 130.27

= 1781.90325819221

Therefore, the total CO2 emissions from the flaring of coal seam waste gas = 1,781.90 tonnes.

## Subdivision 3.2.2.4—Fugitive emissions from post-mining activities

Most fugitive greenhouse gas emissions are released from coal during the mining process. However some residual gas remains trapped within the coal after extraction, and is slowly released during, handling, transportation and stockpiling of the coal.

## 3.17 Method 1—post-mining activities related to gassy mines

Method 1 for estimating emissions from post-mining activities, with the source as described in IPCC 2006, is associated with gassy underground mines only.

The method is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*. Emissions are estimated by multiplying a (physical) quantity of run-of-mine coal extracted by an emission factor.

It is intended that consideration will be given to the development of additional higher order methods for this source in future.

- (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,  $EF_j$  is taken to be 0.017, which is the emission factor for methane (*j*), measured in CO<sub>2</sub>-e tonnes per tonne of run-of-mine coal extracted from the mine.

# **Division 3.2.3—Open cut mines**

Fugitive emissions from open cut mines involve the release of methane and carbon dioxide during the mining process due to the fracturing of coal seams, overburden and underburden strata. Emissions also occur when coal mine waste gas is flared or is vented during degasification of the coal seams prior to the commencement of coal extraction.

## 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.

	CO <sub>2</sub>	CH4	N2O					
Open cut mining activities								
Method 1	NA	Section 3.20	NO					
Method 2	Section 3.21	Section 3.21	NO					
Method 3	Section 3.26	Section 3.26	NO					
Method 4	NA	NA	NO					
Flaring								
Method 1	Section 3.27	Section 3.27	Section 3.27					
Method 2	Section 3.28	NA	NA					
Method 3	Section 3.29	NA	NA					
Method 4	NA	NA	NA					
Venting								
Methods 1, 2 and 3	NA	NA	NO					
Method 4	Part 1.3	Part 1.3	NO					

Summary of available methods for estimating emissions from open cut mines, by emissions of gas type  $\left(j\right)$ 

NA = Not available. NO = Not occurring

# Subdivision 3.2.3.2—Fugitive emissions from extraction of coal

Method 1 for open cut mining operations associated with the extraction of coal is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*. Emissions are estimated for a particular location of the mine by multiplying a (physical) quantity of run-of-mine coal extracted by an emission factor.

#### 3.20 Method 1—extraction of coal

For paragraph 3.19(2)(a), method 1 is:

 $E_i = Q \times EF_i$ 

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<sub>2</sub>-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<sub>2</sub>-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 -0.02;
- (d) for a mine in Western Australia 0.02;
- (e) for a mine in South Australia 0.00027;
- (f) for a mine in Tasmania 0.017.

#### Example

A facility constituted by an open cut coal mine in NSW extracts 2,554,000 tonnes of run-ofmine coal during the year. The Reporter elects to use Method 1 (Section 3.20) to estimate fugitive emissions of methane. Emissions are estimated as follows:

$$E_j = Q \times EF_j$$

where:

 $E_j$  is the emissions of methane (j) released from the extraction of coal from the mine during the year, measured in CO<sub>2</sub>-e tonnes.

Q is the quantity of run-of-mine coal extracted from the mine during the year, measured in tonnes. In this case being 2,554,000 tonnes of raw coal.

 $EF_j$  is the emission factor for methane (j), measured in  $CO_2$  e tonnes per tonne of raw coal extracted from the mine. In this case, for an open cut mine in NSW the emission factor is 0.054 tonnes  $CO_2$ -e per tonne of raw coal extracted.

Therefore, the estimate of methane emissions in CO<sub>2</sub>-e tonnes:

 $E_i = (2,554,000 \ge 0.054)$ 

Total emissions of methane  $= 137,916 \text{ t CO}_2\text{-e}$ 

### 3.21 Method 2—extraction of coal

Method 2 for estimating emissions from open cut mining requires the estimation of the total in-situ stock of gas held within the mine's gas bearing strata.

The framework for the method is based on the following ACARP project:

Saghafi, A. (2008), *Evaluating a tier 3 method for estimating fugitive emissions from open cut mining,* Joint Research Project ACARP (C15076) and CSIRO. CSIRO Investigation Report ET/IR 1011. This report can be obtained from: http://www.acarp.com.au/reports.aspx.

To facilitate the practical application of Method 2/3, an elaboration of the method through amendments to the Determination were introduced for the 2012/13 reporting year.

In parallel to these latest amendments, ACARP published an industry guideline on December 2011 as *Project C20005: Guidelines for the Implementation of NGER* 

*Method 2 or 3 for Open Cut Coal Mine Fugitive GHG Emissions Reporting.* The document contains guidance for the measurement, estimation and reporting of fugitive emissions from open cut mines and is available at: www.acarp.com.au/abstracts.aspx?repId=C20005

The Determination amendments incorporate the ACARP guidelines through the referencing of specific sections of the guidelines. The ACARP Guidelines should be read in conjunction with the Determination. In cases of apparent inconsistency between the ACARP Guidelines and the Determination, the Determination takes precedence.

The Technical Guidelines have been updated to include the amendments to open cut mine methods 2/3. Key changes include:

- The introduction of a low gas zone approach, for which methods for defining a low gas zone and an emission factor are provided.
- The introduction of the Estimator, along with setting minimum qualification for the Estimator.
- Guidance on sampling, analysis, data validation and gas distribution modelling are provided through references within the Determination to relevant sections of the ACARP Guidelines.

A number of new definitions were introduced as part of the set of amendments associated with the elaboration of methods 2/3 for open cut mines. Definitions are listed in section 1.8 of the Determination. Those related to methods 2/3 for open cut mines include the following;

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.

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

*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.

*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.

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  $1.95 \text{ g/cm}^3$ .

*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.

#### 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.
- (1) For paragraph 3.19(2)(b) and subsection 3.19(3), method 2 is:

$$\mathbf{E}_{j} = \boldsymbol{\gamma}_{j} \ \boldsymbol{\Sigma}_{z} \left( \mathbf{S}_{j,z} \right)$$

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<sub>2</sub>-e tonnes.

 $\gamma_j$  is the factor for converting a quantity of gas type (*j*) from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-e tonnes, as follows:

(a) for methane— $6.784 \times 10^{-4} \times 25$ ;

(b) for carbon dioxide— $1.861 \times 10^{-3}$ .

 $\sum_{z} (S_{j,z})$  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:

$$\mathbf{S}_{jz} = \mathbf{M}_{z} \ \times \ \boldsymbol{\beta}_{z} \ \times \ \mathbf{GC}_{jz} - \ \boldsymbol{\Sigma}_{t} \ \mathbf{Q}_{ij, \, \text{cap}, z} - \ \boldsymbol{\Sigma}_{t} \ \mathbf{Q}_{ij, \text{flared}, z} \ - \ \boldsymbol{\Sigma}_{t} \ \mathbf{Q}_{ijtr} \ - \ \boldsymbol{\Sigma}_{t} \ \mathbf{E}_{j, \text{vented}, z}$$

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.

 $\beta_z$  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.

 $\sum E_{j,vented,z}$  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  $\sum Q_{ij,cap,z}$ ,  $\sum Q_{ij,flared,z}$  and  $\sum Q_{ijtr}$  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  $\sum Q_{ij,cap,z}$ -quantities of gaseous fuels captured from the operation of a facility;
  - (b) for  $\sum_{t} Q_{ij,flared,z}$ -quantities of gaseous fuels flared from the operation of a facility;
  - (c) for  $\sum Q_{ijtr}$ —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 *GC<sub>jz</sub>* 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  $\beta_z$  in subsection 3.22(1), estimate  $\beta_z$  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

Measurement of the gas content from coal and other gas bearing strata layers requires use of borecores. Geological characteristics can help to identify possible gas bearing areas based on previous evidence of gas content in a region and to infer gas content of coal and rock strata between actual borecore measurements. However knowledge of geological characteristics of a site, with no specific borecore measurements, would not be able to adequately predict gas content (Saghafi, 2008).

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  $0.5 \text{ m}^3/\text{t}$ ; 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

Method 2 is the same as method 2 under section 3.15. Method 2 requires representative and unbiased samples of coal mine waste gas consumed and analysis of the coal mine waste gas to determine gas composition and must be done in accordance with Australian or equivalent international standards and as set out for Division 2.3.3

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

Method 3 is the same as for Method 2 except that it requires samples to be obtained in accordance with Australian or equivalent international standards and as set out in Division 2.3.4.

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**

Greenhouse gas emissions are known to occur following the closure of coal mines. Leakages to the atmosphere occur through fractured rock strata, open vents and seals over daily to decadal timescales. However, emissions will be reduced by flooding of the mine, which prevents desorption of gases from the remaining coal strata and non-coal strata layers in the closed mine.

# Subdivision 3.2.4.1—Preliminary

# 3.30 Application

This Division applies to fugitive emissions from decommissioned underground mines that have been closed for a continuous period of at least 1 year but less than 20 years.

# 3.31 Available methods

 Subject to section 1.18, for estimating emissions released during a year from the operation of a facility that is constituted by a decommissioned underground mine that has been closed for a continuous period of at least 1 year but less than 20 years 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 for combustion during the year, method 1 in subsection (2) must not be used.

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O					
Underground decommissioned mines								
Method 1	NA	Section 3.32	NO					
Methods 2, 3	NA	NA	NO					
Method 4	Section 3.37	Section 3.37 NO						
Flaring								
Method 1	Section 3.38	Section 3.38	Section 3.38					
Method 2 Section 3.39		NA	NA					
Method 3 Section 3.40		NA	NA					
Method 4	NA	NA	NA					

Summary of available methods for estimating emissions from decommissioned mines, by emissions of gas type (j)

NA = Not available. NO = Not occurring

# Subdivision 3.2.4.2—Fugitive emissions from decommissioned underground mines

Method 1 for emissions from decommissioned mines is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*.

## 3.32 Method 1—decommissioned underground mines

(1) For paragraph 3.31(2)(a), method 1 is:

 $\boldsymbol{E}_{dm} = \begin{bmatrix} \boldsymbol{E}_{tdm} \times \ \boldsymbol{E}\boldsymbol{F}_{dm} \ \times \ (1 \ - \ \boldsymbol{F}_{dm}) \end{bmatrix}$ 

where:

 $E_{dm}$  is the fugitive emissions of methane from the mine during the year measured in CO<sub>2</sub>-e tonnes.

 $E_{tdm}$  is the emissions from the mine for the last full year that the mine was in operation measured in CO<sub>2</sub>-e tonnes and estimated under section 3.5 or 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<sub>2</sub>-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

The emission factor for Method 1 is derived from an emission decay curve (EDC). The EDC describes the decline in fugitive methane emissions overtime following mine closure. Hyperbolic curves have been found to function best in portraying the rapid decline in emissions in the first few years, followed by a slow decline over time of the remaining emissions (*National Inventory Report*).

Australian-specific EDCs developed for the national inventory have being utilized for both gassy and non-gassy mines.

For section 3.32,  $EF_{dm}$  is the integral under the curve of:

 $(1 + A \times T)^{\scriptscriptstyle b} - C$ 

for the period between *T* and *T*-1, where:

**A** is:

- (a) for a gassy mine—0.23; or
- (b) for a non-gassy mine—0.35.

*T* is the number of years since the mine was decommissioned.

**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

Emissions from decommissioned mines are reduced as a mine floods due to the reduction of gas desorption from the coal remaining in the closed mine. The variables required to estimate the portion of the mine flooded at a point in time is the size of the void volume and the water inflow rate into the closed mine.

For subsection 3.32(1),  $F_{dm}$  is:

$$\frac{M_{WI}}{M_{VV}} \times years$$

where:

 $M_{WI}$  is the rate of water flow into the mine in cubic metres per year as measured under section 3.35.

 $M_{VV}$  is the mine void volume in cubic metres as measured under section 3.36.

years is the number of years since the mine was decommissioned.

#### 3.35 Water flow into mine

For  $M_{WI}$  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  $M_{VV}$  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

Emissions using Method 1 are estimated by multiplying the quantity of gas flared by the energy content and emission factor for the coal mine waste gas. The quantity of coal mine waste gas flared should be estimated in accordance with Division 2.3.6. The energy content and emission factors are obtained from Division 2.3.2 of Chapter 2.

- (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**

This part includes fugitive emissions from exploration, production, transport, storage, processing and refining of oil or gas.

Other sources of emissions arising from the production processes, such as from the combustion of fuels for energy, are not described in this chapter and must be estimated using the Methods described in other chapters.

Fugitive emissions in the oil and gas sector can be largely classified as being either a vent, leak or a flare. A flare involves the combustion of a gas or liquid for a nonenergy purpose. The distinction between leaks and vents was derived from the definition used by the American Petroleum Institute Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry (API) and was developed for the application for the Determination in consultation with industry.

#### <u>Vent</u>

Vents are considered to be emissions that are the result of process or equipment design or operational practices; and;

#### Leak

Leaks are considered to be emissions from unintentional equipment leaks from valves, flanges, pump seals, compressor seals, relief valves, sampling connections, process drains, process drains, open-ended lines, casing, tanks, casing leaks and other leakage sources from pressurised equipment not defined as a vent.

The Determination makes use of methods for estimating emissions from vents and leaks in the API Compendium. Amendments for July1 2012 have updated references from the 2004 API to the 2009 version of the API Compendium. The Determination refers to specific section of API 2009 for methods such as engineering approaches and activity or equipment type factors. Most sections of the API Compendium provide the gas content basis for the emission factors and note that the factors can be adjusted based on site-specific gas composition.

#### Conversion flared cubic meters to flared tonnes

Depending on the original data units available to reporters, method 1 for estimating emissions from flaring may require a density conversion for the quantity of fuel type flared from cubic metres to tonnes. Rather than the Determination setting a default density, it is considered that the reporter would be best positioned to understand the characteristics of their flared gas stream. Considerable variability would be expected in the density of flare gas depending on plants and processes, and therefore a universal default figure is unlikely to be useful.

To complement the reporters understanding of their flared gas stream, various gas density values are available in national and international literature such as in the API 2009 Compendium or National Pollution Inventory manuals. Conversions are required to be estimated in standard conditions as specified in the Determination in 2.32 (7). Site specific density figures may also be derived using sampling and measurement approaches under section 2.24 of the Determination. Reporters are reminded of that the approach should be consistent with the general principles detailed in Section 1.13 of the Determination.

# 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

Emissions may occur during the process of drilling for oil or gas either during exploration or development drilling whenever gas or liquid hydrocarbons are encountered. CO<sub>2</sub>, some unburnt methane and N<sub>2</sub>O are released as a result of the flaring of oil or gas. Emissions may also occur as a result of venting and accidental releases such as blowouts.

# 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

Methods 1, 2 and 3 are set out below for the estimation of emissions from flaring of fuel. Flaring is the combustion of fuels for non-productive (non-commercial) reasons –for example for health and safety reasons. Methods 2 and 3 rely on the sampling and analysis of the fuel to estimate the composition of the gases in the fuel in accordance with the provisions of chapter 2.

- (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.

Summary of available methods, for estimating flaring emissions from oil and gas exploration, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O	
Method 1	Section 3.44	Section 3.44	Section 3.44	
Method 2	Section 3.45	NA	NA	
Method 3	Section 3.46	NA	NA	
Method 4	NA	NA	NA	

NA = Not available.

#### **3.44** Method 1—oil or gas exploration

Method 1 for oil exploration and gas exploration is derived from the National Greenhouse Accounts.

(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<sub>2</sub>-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<sub>2</sub>-e emissions per tonne of the fuel type (*i*) flared.

Item	Fuel type (i)	Emission factor for gas type ( <i>j</i> ) (tonnes CO <sub>2</sub> -e/tonnes of fuel flared)				
		$\mathbf{CO}_2$	$\mathbf{CH}_4$	$N_2O$		
1	Unprocessed gas flared	2.8	0.8	0.03		
2	Crude oil	32	0.008	0.07		

(2) For *EF<sub>ij</sub>* 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.

# 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<sub>2</sub> from fuel type (*i*) flared in oil or gas exploration during the year, measured in CO<sub>2</sub>-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<sub>2</sub>-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<sub>2</sub> within fuel type (*i*) in oil or gas exploration during the year, measured in CO<sub>2</sub>-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<sub>2</sub>-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<sub>2</sub>-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<sub>h</sub>* 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

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

An optional method 4 has been introduced for estimating vented methane and carbon dioxide emissions from coal seam gas well completions and workovers. Two approaches are provided:

1) Vented volume measured for all wells and well types in a basin;

where all vented volumes for well completions or workover are measured for all well types(vertical and horizontal); and

2) Vented volume measured for a sample of wells and well types in a basin;

where the total emissions for well completions or workovers are estimated based on the measurement of flow rate taken from a sample of the well population during the year.

#### Conversion to standard conditions

All gas volumes are to be converted to standard conditions as set out in 2.32(7).

Measurement of gaseous quantities.

Division 2.3.6 sets out requirements for the measurement of gaseous quantities, including criterion BBB - estimation in accordance with industry practice).

#### Vented volume measured for all wells and well types in a basin

Emissions arising from both strata and gas injected for each well are summed and converted to carbon dioxide equivalents in subsection (1).

The volume of methane vented from the strata for each well  $(ES_p)$  is estimated in subsection (2). Methane volume from strata is estimated by subtracting the volume of gas measured on the vent line from the any volumes of gas injected during a completion or workover. This approach assumes that gas volumes from strata are methane and therefore gas compositional analysis under Division 2.3.3 is not required.

The volume of any injected methane and carbon dioxide (*VIGG*  $_{jp}$ ) is estimated in subsection (3). Compositional analysis of the gas under Division 2.3.3 is required to separate methane and carbon dioxide components of the injected gas.

(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:

$$Em_{j} = \gamma_{j} \times \left[ \sum_{p=1}^{W} ES_{p} + \left( \sum_{j=1}^{Z} VIGG_{j,p} \right) \right]$$

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<sub>2</sub>-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.

 $\gamma_j$  is the factor for converting a quantity of gas type (*j*) from cubic metres at standard conditions to CO<sub>2</sub>-e tonnes, being:

- (a) for methane— $6.784 \times 10^{-4} \times 25$ ; and
- (b) for carbon dioxide— $1.861 \times 10^{-3}$ .

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<sub>j,p</sub>* is worked out using the following formula: VI<sub>p</sub> × mol<sub>j,p</sub>%

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

# Vented volume measured for a sample of wells and well types in a basin

The vented volume is estimated in subsection (4) by using a sampling approach, where a subset of all the well completions/workers, by well type, are sampled during the year for a basin. Subsection (8) sets out the well sampling requirements where, for well completions or workovers, a minimum of 10% of all well types in a basin are to be sampled.

Measurement is required of the flow rate for both the flowback and the first 30 day production, in accordance with Division 2.3.6, to derive average flow rates. These average flow rates are used in subsection (7) to derive the ratio of flowback to 30 day production rate (*FRM<sub>bt</sub>*) for each well type sampled.

In subsection (5), the ratio (*FRM<sub>bt</sub>*) is extrapolated to all respective well completion/workovers in the basin during the year to give  $EV_p$ , being the estimated volume of methane flowback during well completions/workovers from strata, for each well.

Subection (4) estimates net vented emissions for each well by allowing for the subtraction of captured or flared gas type volumes and the addition of gas volume types injected, before finally summing emission net emissions across all wells.

(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:

$$Em_{j} \;=\; \gamma_{j} \;\times \Bigg[\sum_{p=1}^{W} EV_{p} \;+\; \sum_{j=1}^{Z} \Bigl(VIGG_{j,p} \;-\; SG_{j,p}\Bigr)\Bigg]$$

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<sub>2</sub>-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.

 $\gamma_j$  is the factor for converting a quantity of gas type (*j*) from cubic metres at standard conditions to CO<sub>2</sub>-e tonnes, being:

- (a) for methane— $6.784 \times 10^{-4} \times 25$ ; and
- (b) for carbon dioxide— $1.861 \times 10^{-3}$ .

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<sub>j,p</sub>* is worked out using the following formula: VI<sub>p</sub> × mol<sub>i,p</sub>%

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  $FRM_{bt}$  is worked out using the following formula:

$$\frac{\displaystyle\sum_{p=1}^{N} FR_{p(bt)}}{\displaystyle\sum_{p=1}^{N} PR_{p(bt)}}$$

where:

 $FR_{p(bt)}$  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.

 $PR_{p(bt)}$  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.

< **-**

Example of estimating vented emissions from well completions and well workovers using method 4 - subsection (1) *Vented volume measured for all wells and well types in a basin* 

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Where in subsection (1)

$$\mathrm{Em}_{j} = \gamma_{j} \times \left[ \sum_{p=1}^{W} \mathrm{ES}_{p} + \left( \sum_{j=1}^{Z} \mathrm{VIGG}_{j,p} \right) \right]$$

#### **Input Data**

An example is detailed in the table below of a company performing four well completions during the year in a basin. The company chooses to use the method 4 approach set out in subsection (1) where the vented volume is measured for all four wells. The volume of the flowback gas and gas injected were measured for each well and converted to standard conditions (columns B and C). The methane and carbon dioxide composition of the injected were determined (columns D and E)

Α	В	С	D	Е	F	G	Н	
Well No.	Flow volume of flowback measured for well in standard conditions	Volume of gas injected into well, in standard conditions	CH <sub>4</sub> share of one mole of VI <sub>p</sub> , as a percentage	CO <sub>2</sub> share of one mole of VI <sub>p</sub> , as a percentage	Volume of CH <sub>4</sub> injected into well	Volume of CO <sub>2</sub> injected into well	Volume of CH <sub>4</sub> vented from strata for each well	
	$FV_p$	$VI_p$	mol <sub>p</sub> %	mol <sub>p</sub> %	VIGG <sub>p</sub>	VIGG <sub>p</sub>	$ES_p$	
	Cubic metres	Cubic metres	%	%	Cubic metres	Cubic metres	Cubic metres	
					D x C	ExC	B - C	
1	22	2	20	80	0.4	1.6	20	
2	50	5	25	75	1.25	3.75	45	
3	27	8	90	10	7.2	0.8	19	
4	15	4	95	5	3.8	0.2	11	

Note: Relatively small quantities have been used for simplicity of example.

Step 1 Calculate VIGG<sub>jp</sub> - the volume of CH<sub>4</sub> and CO<sub>2</sub> injected into each well.

 $VIGG_{j,p}$  is worked in subsection (3) using the following formula:

#### $VI_p \times mol_{j,p} \%$

Referring to the table above,  $VIGG_p$  for methane and carbon dioxide have been worked out for each well in columns F and G respectively.

Step 2 Calculate  $ES_p$ ; the volume of CH<sub>4</sub> vented from strata for each well.

 $ES_p$  is worked in subsection (2) using the following formula:

FV<sub>p</sub> - VI<sub>p</sub>

Referring to the table above,  $ES_p$  has been worked out for each well in column H.

Step 3 Calculate total vented methane and carbon dioxide volumes for each well:

For methane (column I) =  $ES_p$  (column H) +  $VIGG_p$  (column F)

For carbon dioxide (column J) =  $VIGG_p$  (column G)

Α	F	н	I	J CO <sub>2</sub> well emissions. Equals the Volume of CO <sub>2</sub> injected into well	
Well No.	Volume of CH₄ injected into well	Volume of CH <sub>4</sub> vented from strata for each well	CH₄ well emissions		
	$(VIGG_p)$	$(ES_p)$		$(VIGG_p)$	
	Cubic metres	Cubic metres	Cubic metres	Cubic metres	
			$\mathbf{F} + \mathbf{H}$	G	
1	0.4	20	20.4	1.6	
2	1.25	45	46.25	3.75	
3	7.2	19	26.2	0.8	
4	3.8	11	14.8	0.2	



Methane = 1.8257 tonnes CO<sub>2</sub>-e

Carbon dioxide = 0.012 tonnes CO<sub>2</sub>-e

Example of estimating vented emissions from well completions and well workovers using method 4 - subsection (1) *Vented volume measured for a sample of wells and well types in a basin* 

Where in subsection (4)

$$Em_{j} = \gamma_{j} \times \Bigg[ \sum_{p=1}^{W} EV_{p} + \sum_{j=1}^{Z} \Bigl( VIGG_{j,p} - SG_{j,p} \Bigr) \Bigg]$$

#### **Input Data**

An example is detailed in the table below of a company performing four well completions during the year in a basin. The company chooses to use the method 4 approach set out in subsection (4) where the vented volume is estimated using the measurement of flowback and production rate within a well sampling framework.

The average rate of flowback gas per well completion ( $FR_{p(bt)}$ ) and the average 30 day production rate per well ( $PR_{p(bt)}$ ) were determined by measurement (columns B and C).

The total number of hours of flowback for the well completion ( $T_p$ ) were recorded (column D).

The volumes of gas injected were measured for each well ( $VI_p$ ) and converted to standard conditions (column E). The methane and carbon dioxide composition ( $mol_{j,p}$ %) of the injected gas were determined (columns F and G). Volumes of methane and carbon dioxide captured during well completions ( $SG_{j,p}$ ), converted to standard conditions, were estimated for each well (columns J and K).

Α	В	С	D	Е	F	G	Н	Ι	J	K
Well No.	Average rate of flowback gas per well completio n	Average 30 day productio n rate per well	Number of hours of flowback for the well completio n	Volume of gas injected into well	$\begin{array}{c} CH_4\\ share of\\ one mole\\ of VI_p, as\\ a\\ percentag\\ e\end{array}$	$CO_2$ share of one mole of $VI_p$ , as a percentag e	Volume of CH <sub>4</sub> injected into well	Volume of CO <sub>2</sub> injected into well	Volume of CH <sub>4</sub> captured	Volumes of CO <sub>2</sub> captured
	$FR_{p(bt)}$	$PR_{p(bt)}$	$T_p$	$VI_p$	mol <sub>p</sub> %	mol <sub>p</sub> %	VIGG <sub>p</sub>	VIGG <sub>p</sub>	$SG_{j,p}$	$SG_{j,p}$
	Cubic metres per hour	Cubic metres per hour	Hours	Cubic metres	%	%	Cubic metres	Cubic metres	Cubic metres	Cubic metres
							ExF	ExG		
1	5	2	22	2	20	80	0.4	1.6	8	0.5
2	4	2	50	5	25	75	1.25	3.75	8	1
3	3	1	27	8	90	10	7.2	0.8	7	0
4	6	4	87	4	95	5	3.8	0.2	8	0

Note: Relatively small quantities have been used for simplicity of example.

#### Step 1 Determine the well sampling requirements:

Sampling requirments are set out in subsection (8). In this example only four vertical well completions were performed in the basin during the year. Therefore, according to paragraph (8)(a), all four wells are required to be measured.

Step 2 Calculate *FRM*<sub>bt</sub>; the ratio of flowback during well completions to the 30 day production rate for each well.

 $FRM_{bt}$  is worked in subsection (7) using the following formula:


Therefore  $FRM_{bt}$  is calculated for each well in column L of the following table:

A	В	С	L
Well No.	Average rate of flowback gas per well completion	Average 30 day production rate per well	The ratio of flowback during well completions to the 30 day production rate
	$FR_{p(bt)}$	$PR_{p(bt)}$	$FRM_{bt}$
	Cubic metres per hour	Cubic metres per hour	
			B / C
1	5	2	2.5
2	4	2	2
3	3	1	3
4	6	4	1.5

Step 3 Calculate  $EV_p$ ; the volume of methane flowback during a well completion from strata for each well.

 $EV_p$  is worked in subsection (5) using the following formula:

$$T_p \times FRM_{bt} \times PR_p$$
 -  $VI_p$ 

Therefore  $EV_p$  is calculated for each well in column M of the following table:

Α	D	L	С	Ε	М
Well No.	Number of hours of flowback for the well completion	The ratio of flowback during well completions to the 30 day production rate	Average 30 day production rate per well	Volume of gas injected into well, in standard conditions	Volume of CH <sub>4</sub> flowback during a well completion from strata
	$T_p$	FRM <sub>bt</sub>	$PR_{p(bt)}$	$VI_p$	$EV_p$
	Hours		Cubic metres per hour	Cubic metres	Cubic metres
					D x L x C - E
1	22	2.5	2	2	108
2	50	2	2	5	195
3	27	3	1	8	73
4	87	1.5	4	4	518

Step 4 Calculate VIGG<sub>jp</sub>; the volume of CH<sub>4</sub> and CO<sub>2</sub> injected into each well.

*VIGGj,p* is worked in subsection (6) using the following formula:

 $VI_p \times mol_{j,p}\,\%$ 

Referring to the input data table,  $VIGG_{j,p}$  for methane and carbon dioxide have been worked out for each well in columns H and I respectively.

Step 5 Calculate total vented methane and carbon dioxide volumes for each well:

For methane (column N) =  $EV_p$  (column M) +  $VIGG_p$  (column H) -  $SG_p$  (column J)

Α	М	Н	J	N
Well No.	Volume of CH <sub>4</sub> injected into well	Volume of CH <sub>4</sub> injected into well	Volume of CH <sub>4</sub> captured	CH4 well emissions
	$EV_p$	VIGGp	$SG_p$	
	Cubic metres	Cubic metres	Cubic metres	Cubic metres
				M + H - J
1	108	0.4	8	100.4
2	195	1.25	8	188.25
3	73	7.2	7	73.2
4	518	3.8	8	513.8

For carbon dioxide (column O) =  $VIGG_p$  (column I) -  $SG_p$  (column K)

Α	I	K	0
Well No.	Volume of CO <sub>2</sub> injected into well	Volume of CO <sub>2</sub> captured	CO <sub>2</sub> well emissions
	VIGG <sub>p</sub>	$SG_{p}$	
	Cubic metres	Cubic metres	Cubic metres
			I - K
1	1.6	0.5	1.1
2	3.75	1	2.75
3	0.8	0	0.8
4	0.2	0	0.2

Step 6 Calculate final methane and carbon dioxide emissions for all wells:

Sum emissions for all wells by gas type and convert from cubic metres to tonnes CO2-e.

For methane

sum column N

= 100.4 + 188.25 + 73.2 + 513.8

= 875.65 m3

Apply methane conversion factor  $\gamma_j = 6.784 \times 10-4 \times 25$ 

 $= 875.65 \text{ x } 6.784 \times 10-4 \times 25$ 

= 14.851 tonnes CO2-e

For carbon dioxideSum column O= 1.1 + 2.75 + 0.8 + 0.2= 4.85 m3Apply carbon dioxide conversion factor  $y_1 = 1.861 \times 10^{-3}$  $= 4.85 \times 1.861 \times 10^{-3}$ = 0.009 tonnes CO2-eTherefore: total vented emissions from well completions performed to the four wells during the year are:Methane = 14.851 tonnes CO2-e

Carbon dioxide = 0.009 tonnes CO<sub>2</sub>-e

### **Division 3.3.3—Crude oil production**

Emissions arise for this category from fugitive sources such as leaks, accidental releases, vents, storage losses and from flaring of fuels (that is, the combustion of fuels for non-productive or non-commercial reasons) – for example for health and safety reasons.

### 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

Fugitive leakage emissions of methane may occur in crude oil production from sources such as the unintentional equipment leaks from valves, flanges, pump seals, compressor seals, relief valves, sampling connections, process drains, open-ended lines, casing, tanks and other leakage sources from pressurised equipment not classed as a vent.

#### 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.

### Summary of available methods, for estimating fugitive leak emissions from crude oil production (non-flared), by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	NO	Section 3.49	NO
Method 2	NO	Section 3.50	NO
Method 3	NO	NA	NO
Method 4	NO	NA	NO

NA = Not available. NO = Not occurring

## 3.49 Method 1—crude oil production (non-flared) emissions of methane

(1) Method 1 is:

$$\mathrm{E}_{ij} = \Sigma_{\mathrm{k}} \left( \mathrm{Q}_{\mathrm{ik}} \times \mathrm{EF}_{\mathrm{ijk}} 
ight) + \mathrm{Q}_{\mathrm{i}} \times \mathrm{EF}_{\mathrm{(l)} \ \mathrm{ij}}$$

where:

 $E_{ij}$  is the fugitive emissions of methane (*j*) from the crude oil production during the year measured in CO<sub>2</sub>-e tonnes.

 $\Sigma_k$  is the emissions of methane (*j*) measured in tonnes of CO<sub>2</sub>-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<sub>2</sub>-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 x 10<sup>-3</sup>, which is the emission factor for methane (*j*) from general leaks in the crude oil production, measured in CO<sub>2</sub>-e tonnes per tonne of crude oil that passes through the crude oil production.

Item	Equipment type (k)	Emission factor for gas type (j) (tonnes CO <sub>2</sub> -e/tonnes fuel throughput) CH <sub>4</sub>
1	Internal floating tank	$1.0 \times 10^{-6}$
2	Fixed roof tank	$5.0 \times 10^{-6}$
3	Floating tank	$4.0 \times 10^{-6}$

(2) For *EF<sub>ijk</sub>* 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:

(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

Method 2 requires the use of equipment-specific emission factors and more detail on the types of equipment used at the facility. The Method is intended to be as specified in the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry 2009*, sections 5 and 6.1.2.

(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<sub>2</sub>-e tonnes.

 $\Sigma_k$  is the emissions of methane (*j*) measured in tonnes of CO<sub>2</sub>-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<sub>2</sub>-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

Methods 1, 2 and 3 are provided for flaring of fuels. Methods 2 and 3 rely on the sampling and analysis of the fuel to estimate the composition of the gases in the fuel in accordance with the provisions of chapter 2.

### 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.

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 3.52	Section 3.55	Section 3.55
Method 2	Section 3.53	NA	NA
Method 3	Section 3.54	NA	NA
Method 4	NA	NA	NA

Available methods, for estimating emissions from crude oil production (flared), by emissions of gas type (j)

NA = Not available. NO = Not occurring

### 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<sub>2</sub>-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<sub>2</sub>-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 <sub>2</sub> -e/tonnes of fuel flared)		type (j) (tonnes red)
		CO <sub>2</sub>	CH <sub>4</sub>	$N_2O$
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<sub>2</sub> from fuel type (*i*) flared in crude oil production during the year, measured in CO<sub>2</sub>-e tonnes.

 $Q_h$  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.

 $EF_h$  is the emission factor for the total hydrocarbons (h) within the fuel type (i) in crude oil production during the year, measured in CO<sub>2</sub>-e tonnes per tonne of fuel type (i) flared, estimated in accordance with method 2 in 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<sub>2</sub> within the fuel type (*i*) in crude oil production during the year, measured in CO<sub>2</sub>-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  $EF_h$  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:

 $EF_{hij}$  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<sub>2</sub>-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 production during the year, measured in CO<sub>2</sub>-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 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  $EF_h$  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<sub>h</sub>* 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.

### Summary of available methods, for estimating fugitive vent emissions from crude oil production (non-flared), by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 3.56A	Section 3.56A	NO
Method 2	NA	NA	NO
Method 3	NA	NA	NO
Method 4	Part 1.3	Part 1.3	NO

NA = Not available. NO = Not occurring

#### Example

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

The Reporter elects to use Method 1 to calculate fugitive emissions from crude oil production and flaring, for each of the greenhouse emission gases (j) (carbon dioxide, methane and nitrous oxide). Emissions are estimated as follows:

Part A: Crude oil production (non flared component)

$$E_{ij} = \Sigma_k \left( Q_{ik} \times EF_{ijk} \right) + Q_i \times EF_{(1)ij}$$

where:

 $E_{ij}$  is the emissions measured in  $CO_2$  e tonnes of methane (j), released from the crude oil production during the year.

 $\Sigma_k$  is the sum of emissions of methane (j) (tonnes of CO<sub>2</sub>-e) arising from equipment of types (k) listed in the table in section 3.49.

 $Q_{ik}$  is the total of the quantities of crude oil (tonnes) that pass through each equipment of type (k) listed in the table in section 3.49. In this case it is the crude oil throughput for the floating tank is 685,000 tonnes.

 $EF_{ijk}$  is the emission factor for methane (j) measured as tonnes of CO<sub>2</sub>-e per tonne of crude oil that passes through each equipment of type (k). In this case the emission factor for the floating tank is 3.2 x 10<sup>-6</sup> CO<sub>2</sub>-e/tonnes fuel throughput.

Q<sub>i</sub> is the total quantity of crude oil (i) measured in tonnes of crude oil production. **In this case the crude oil production throughput is 710,400 tonnes**.

 $EF_{(1) ij}$  **1.4 x 10<sup>-3</sup>**, is the emission factor for methane (j) from general leaks in the crude oil production, measured in CO<sub>2</sub> e tonnes per tonne of crude oil production.

Therefore, the estimate of methane emissions in CO<sub>2</sub>-e tonnes :

 $= (685,000 \text{ x } 4.0 \text{ x } 10^{-6}) + (710,400 \text{ x } 1.4 \text{ x } 10^{-3})$ 

Total emissions of methane  $= 997 \text{ t CO}_2\text{-e}$ 

Part B: Crude oil production (flared component)

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

where:

 $E_{ij} \ is \ the \ emissions \ of \ gas \ type \ (j) \ (CO_2-e \ tonnes) \ released \ from \ a \ fuel \ type \ (i) \ flared.$ 

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

 $EF_{ij}$  is the emission factor for gas type (j) in tonnes of CO<sub>2</sub>-e emissions per tonne of the fuel type (i) flared. The emission factors are obtained from Method 1, section 3.52

Therefore, the estimate of greenhouse gas emissions (from carbon dioxide, methane and nitrous oxide (j)) in CO<sub>2</sub>-e tonnes:

For carbon dioxide

=400 x 3.2

Total emissions of carbon dioxide  $= 1280 \text{ t CO}_2\text{-e}$ 

For methane

=400 x 0.008

Total emissions of methane  $= 3 t CO_2$ -e

For nitrous oxide

=400 x 0.07

Total emissions of nitrous oxide  $= 28 \text{ t CO}_2$ -e

Part C: Crude oil production (vented emissions component)

The Reporter is directed to section 3.84 which specifies the applicable sections of the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry 2009*(API Compendium). The reporter estimates their vented emissions in accordance with those methods detailed in the API Compendium, producing the following results:

Total emissions of carbon dioxide  $= 380 \text{ t CO}_2\text{-e}$ 

Total emissions of methane  $= 980 \text{ t CO}_2\text{-e}$ 

### **Division 3.3.4—Crude oil transport**

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

#### 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.

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	NO	Section 3.59	NO
Method 2	NO	Section 3.60	NO
Method 3	NO	NA	NO
Method 4	NO	NA	NO

Available methods, for estimating emissions from crude oil transport), by emissions of gas type (j)

NA = Not available. NO = Not occurring

### 3.59 Method 1—crude oil transport

Method 1 for crude oil transport for fugitive emissions is derived from the *National Greenhouse Accounts*.

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<sub>2</sub>-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 x 10<sup>-4</sup> tonnes CO<sub>2</sub>-e per tonnes of crude oil transported during the year.

### 3.60 Method 2—fugitive emissions from crude oil transport

Method 2 requires the use of equipment-specific emission factors and more detail on the types of equipment used at the facility. The Method is intended to be as specified in the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry 2009*sections 5 and 6.1.2.

(1) Method 2 is: (1)

 $E_{ij} = \Sigma_k \left( Q_{ik} \times EF_{ijk} \right)$ 

where:

 $E_{ij}$  is the fugitive emissions of methane (*j*) from the crude oil transport during the year measured in CO<sub>2</sub>-e tonnes.

 $\Sigma_k$  is the emissions of methane (*j*) measured in tonnes of CO<sub>2</sub>-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<sub>2</sub>-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*<sub>*ijk*</sub>, 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

Emissions arise for this category from fugitive sources (for example gas leaks), flaring and from the process vents, system upsets and accidents, including the combustion of catalyst coke for non-energy purposes.

Other sources of emissions arising from the crude oil refining, such as from the combustion of fuels for energy or from the production of hydrogen, are not described in this chapter and must be estimated using the Methods described in other chapters.

### 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.

### Summary of available methods, for estimating emissions from crude oil refining, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O		
Crude oil refining and stora	ge tanks				
Method 1	NO	Section 3.63	NO		
Method 2	NO	Section 3.64	NO		
Methods 3, 4	NO	NA	NO		
Process vents, system upsets and accidents					
Method 1	Section 3.65	Section 3.65	Section 3.65		
Methods 2, 3	NA	NA	NA		

Method 4	Section 3.66	Section 3.66	Section 3.66
Flaring			
Method 1	Section 3.67	Section 3.67	Section 3.67
Method 2	Section 3.68	NA	NA
Method 3	Section 3.69	NA	NA
Method 4	NA	NA	NA

NA = Not available. NO = Not occurring

## 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 for fugitive emissions from crude oil refining is derived from the *National Greenhouse Accounts*.

Method 1 is:

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

where:

 $E_{ij}$  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<sub>2</sub>-e tonnes.

 $\sum_{i}$  is the sum of emissions of methane (*j*) released during refining and from storage tanks during the year.

 $Q_i$  is the quantity of crude oil (*i*) refined or stored in tanks during the year measured in tonnes.

 $EF_{ij}$  is the emission factor for methane (*j*) being 8.5 x 10<sup>-4</sup> tonnes CO<sub>2</sub>-e per tonne of crude oil refined and 1.5 x 10<sup>-4</sup> tonnes CO<sub>2</sub>-e per tonne of crude oil stored in tanks.

#### 3.64 Method 2—crude oil refining and storage tanks for crude oil

Method 2 for fugitive emissions from crude oil refining requires the use of equipmentspecific emission factors and more detail on the types of equipment used at the facility. The Method is intended to be as specified in the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry 2009* sections 5 and 6.1.2.

(1) Method 2 is:

$$E_{ii} = \Sigma_k (Q_{ik} \times EF_{iik})$$

where:

 $E_{ij}$  is the fugitive emissions of methane (*j*) from the crude oil refining and from storage tanks during the year measured in CO<sub>2</sub>-e tonnes.

 $\Sigma_k$  is the emissions of methane (*j*) measured in tonnes of CO<sub>2</sub>-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.

 $Q_{ik}$  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<sub>2</sub>-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*<sub>*ijk*</sub>, 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 for the estimation of emissions from the burning of catalyst coke for nonenergy purposes is derived from the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry 2009* sections 5.2.

It is intended that there should be no double count or omissions of emissions from the estimation of emissions from the combustion of the catalyst coke. Where it is difficult to distinguish between the emissions from combustion of catalyst coke for non-energy purposes from its use as an energy source, it is intended that all emissions should be attributed to the combustion of fuels for energy.

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<sub>2</sub>-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

Method 4 is provided as an additional option and is taken from the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry 2009* sections 5 and 6.1.2. Consistent with the American Petroleum Institute methodology, emissions of carbon monoxide must be treated as if they fully oxidise to carbon dioxide and estimated accordingly.

- (1) Method 4 is: (1)
  - (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

Flares are commonly used at refineries for the disposal of vented waste gases. The flaring of refinery gases results in the emission of  $CO_2$ , methane, nitrous oxide and products of incomplete combustion. Method 1 is derived from the methods used for the National Greenhouse Accounts. Methods 2 and 3 rely on the sampling and analysis of the fuel to estimate the composition of the gases in the fuel in accordance with the provisions of chapter 2.

#### 3.67 Method 1—gas flared from crude oil refining

(1) Method 1 is:

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

where:

 $E_{ij}$  is the emissions of gas type (*j*) released from the gas flared in the crude oil refining during the year measured in CO<sub>2</sub>-e tonnes.

 $Q_i$  is the quantity of gas type (i) flared during the year measured in tonnes.

 $EF_{ij}$  is the emission factor for gas type (*j*) measured in tonnes of CO<sub>2</sub>-e emissions per tonne of gas type (*i*) flared in the crude oil refining during the year.

(2) For *EF<sub>ij</sub>* 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 <sub>2</sub> -e/tonnes fuel flared)		
		CO <sub>2</sub>	CH <sub>4</sub>	$N_2O$
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:

$$E_{ico_{1}} = Q_{h} \times EF_{h} \times OF_{i} + QCO_{2}$$

where:

 $E_{iCO_2}$  is the fugitive emissions of CO<sub>2</sub> from fuel type (*i*) flared in crude oil refining during the year, measured in CO<sub>2</sub>-e tonnes.

 $Q_h$  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.

 $EF_h$  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<sub>2</sub>-e tonnes per tonne of fuel type (i) flared, estimated in accordance with method 2 in 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<sub>2</sub> within the fuel type (*i*) in the crude oil refining during the year, measured in CO<sub>2</sub>-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<sub>2</sub>-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<sub>2</sub>-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.

### Estimating carbon dioxide emissions from crude oil refining flaring using Method 2

Crude oil refining usually involves some flaring of a waste gas stream. In this example a facility flares a waste gas stream of 10,000 tonnes during the year, which contains a relatively high content of carbon dioxide in addition to some hydrogen sulphide and hydrocarbons. The reporters have chosen to use method 2 as this approach provides the opportunity to develop a carbon dioxide emission factor that better reflects the hydrocarbons present in the gas stream, as well as account for the in-situ carbon dioxide quantity which is emitted, but not combusted in the flare.

Calculate the carbon dioxide emissions using Method 2 in section 3.68 of NGER (Measurement) Determination

$$E_{ico2} = (Q_h \times EF_h \times OF_i) + QCO_2$$

Where:

 $E_ico_2$  is the fugitive emissions of CO<sub>2</sub> from fuel type (*i*) flared in crude oil refining during the year, measured in CO<sub>2</sub>-e tonnes.

 $Q_h$  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.

 $QCO_2$  is the quantity of CO<sub>2</sub> within the fuel type (*i*) in crude oil refining during the year, measured in CO<sub>2</sub>-e tonnes in accordance with Division 2.3.3.

In this example it was determined (in accordance with Division 2.3.3) that the average composition of the waste gas stream being flared during the year is as follows:

Hydrocarbons C1 to C5 = 0.87 tonnes/ tonne of waste gas stream

Hydrogen sulphide = 0.05 tonnes/ tonne of waste gas stream

Nitrogen = 0.02 tonnes/ tonne of waste gas stream

Carbon dioxide = 0.06 tonnes/ tonne of waste gas stream

Therefore:

 $Q_h = 0.87 \times 10,000$  t of waste gas stream flared during the year

Qh = 8700 tonnes

 $QCO_2 = 0.06 \times 10,000 \text{ t of waste gas stream flared during the year}$ 

#### $QCO_2 = 600$ tonnes

*EF*<sub>*h*</sub> is the emission factor for the total hydrocarbons (h) within the fuel type (i) in crude oil refining during the year, measured in CO<sub>2</sub>-e tonnes per tonne of fuel type (i) flared, estimated in accordance with method 2 in Division 2.3.3.

In this example it was determined (in accordance with Division 2.3.3) that the emission factor derived from the average hydrocarbon composition of the waste gas stream being flared during the year was:

2.4 tonnes of  $CO_2$  per tonne of waste gas stream flared

Therefore:

EFh = 2.4

 $OF_i$  is 0.98, which is the correction factor for the oxidation of fuel type (*i*) flared.

To calculate the CO<sub>2</sub> emissions from waste gas flared:

= (8700 x 2.4 x 0.98) + 600 = 21,062.4

Therefore, the total emissions from the source = 21,062 tonnes of CO<sub>2</sub>

### Division 3.3.6—Natural gas production or processing, other than emissions that are vented or flared

Fugitive leakage emissions of methane may occur in natural gas production from sources such as the unintentional equipment leaks from valves, flanges, pump seals, compressor seals, relief valves, sampling connections, process drains, open-ended lines, casing, tanks and other leakage sources from pressurised equipment not classed as a vent.

The venting of CO<sub>2</sub> and methane extracted from raw gas and flaring of unusable gas produced at various stages of processing are separately accounted for under venting and flaring.

Other sources of emissions arising from natural gas production and processing, such as from the combustion of fuels for energy, are not described in this chapter and must be estimated using the Methods described in other chapters.

Note that in this part the definition of natural gas is as follows:

*natural gas* includes coal seam methane that is captured for combustion where the production of coal is not intended to occur

### 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.

Summary of available methods, for estimating emissions from natural gas production and processing (other than emissions that are vented or flared), by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	NO	Section 3.72	NO
Method 2	NO	Section 3.73	NO
Method 3	NO	NA	NO
Method 4	NO	NA	NO

NA = Not available. NO = Not occurring

### **3.72** Method 1—natural gas production and processing (other than emissions that are vented or flared)

(1) Method 1 is:

$$\mathbf{E}_{ij} = \boldsymbol{\Sigma}_{k} \ (\mathbf{Q}_{ik} \ \times \ \mathbf{E} \mathbf{F}_{ijk}) + \mathbf{Q}_{i} \ \times \ \mathbf{E} \mathbf{F}_{(l) \, ij}$$

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<sub>2</sub>-e tonnes.

 $\Sigma_k$  is the total emissions of methane (*j*), measured in CO<sub>2</sub>-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<sub>2</sub>-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<sup>-3</sup>, which is the emission factor for methane (*j*) from general leaks in the natural gas production and processing, measured in CO<sub>2</sub>-e tonnes per tonne of natural gas that passes through the natural gas production and processing.

(2) For *EF<sub>ijk</sub>* 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 <sub>2-e</sub> /tonnes fuel throughput)
1	Internal floating tank	$1.0 \times 10^{-7}$
2	Fixed roof tank	$5.0 \times 10^{-6}$
3	Floating tank	$3.8 \times 10^{-6}$

(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)

Method 2 for fugitive emissions from natural gas production and processing requires the use of equipment-specific emission factors and more detail on the types of equipment used at the facility. The Method is intended to be as specified in the American Petroleum Institute's Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry 2009 sections 5 and 6.1.2.

(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 natural gas production and processing during the year measured in CO<sub>2</sub>-e tonnes.

 $\Sigma_k$  is the emissions of methane (*j*) measured in CO<sub>2</sub>-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<sub>2</sub>-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*<sub>*ijk*</sub>, 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**

Emissions may occur as a result of compressor blow downs for maintenance at compressor stations, maintenance on pipelines, leakage and accidents.

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

Note that in this part the definition of natural gas is as follows:

natural gas includes coal seam methane that is captured for combustion where

the production of coal is not intended to occur

### 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.

Summary of available methods, for estimating emissions from natural gas transmission, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 3.76	Section 3.76	NO
Method 2	Section 3.77	Section 3.77	NO
Method 3	NO	NA	NO
Method 4	NO	NA	NO

NA = Not available. NO = Not occurring

### 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<sub>2</sub>-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<sub>2</sub>-e emissions per kilometre of pipeline (*i*).

#### Example

A company has a network of natural gas transmission pipelines with a total length of 3600 km, over a year. The Reporter elects to use Method 1 to calculate fugitive emissions from natural gas transmission, for carbon dioxide and methane. Emissions are estimated as follows:

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

where:

 $E_{ij}$  is the emissions measured in CO<sub>2</sub> e tonnes of gas type (j), being either carbon dioxide or methane, released from natural gas transmission through a system of pipelines of length (i) during the year measured in CO<sub>2</sub>-e tonnes.



#### 3.77 Method 2—natural gas transmission

Method 2 for fugitive emissions from natural gas transmission requires the use of equipment-specific emission factors and more detail on the types of equipment used at the facility. The Method is intended to be as specified in the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry 2009* sections 5 and 6.1.2. The option is also provided to refine the emission factors from information on the composition of the gases, using the engineering calculations and from information on the leakage rates for specific pipeline materials for the industry.

(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<sub>2</sub>-e tonnes from the natural gas transmission through the system of pipelines during the year.

 $\Sigma_k$  is the total of emissions of gas type (*j*) measured in CO<sub>2</sub>-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.

 $Q_k$  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.

 $EF_{jk}$  is the emission factor of gas type (*j*) measured in CO<sub>2</sub>-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 *EF<sub>jk</sub>*, 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 <u>www.api.org</u>.
### Division 3.3.8—Natural gas distribution

Emissions arise for this category from fugitive sources (for example gas leaks, accidental releases). The boundary between natural gas transmission and distribution is generally taken to be the city gate regulator stations at which gas pressures are reduced from transmission pressures to sub-transmission pressures. For the purposes of this methodology, natural gas distribution comprises low, medium and high-pressure reticulation ≤ 1050 kilopascals.

Other sources of emissions arising from the natural gas distribution, such as from the combustion of fuels for energy, are not described in this chapter and must be estimated using the Methods described in other chapters.

Note that in this part the definition of natural gas is as follows:

natural gas includes coal seam methane that is captured for combustion where

the production of coal is not intended to occur

### 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.

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 3.80	Section 3.80	NO
Method 2	Section 3.81	Section 3.81	NO
Method 3	NA	NA	NO
Method 4	NA	NA	NO

Summary of available methods,	for	estimating	emissions	from	natural
gas distribution, by emissions of	gas	type (j)			

NA = Not available. NO = Not occurring

#### 3.80 Method 1—natural gas distribution

Method 1 for fugitive emissions from natural gas distribution is derived from the *National Greenhouse Accounts*.

(1) Method 1 is: (1)

$$\mathrm{E_{jp}}~=~\mathrm{S_{p}}~\times~\%\mathrm{UAG_{p}}~\times~0.55~\times~\mathrm{C_{jp}}$$

where:

 $E_{jp}$  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<sub>2</sub>-e tonnes.

 $S_p$  is the total sales during the year from the pipeline system in a State or Territory (p), measured in terajoules.

 $%UAG_p$  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.

 $C_{jp}$  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<sub>2</sub>-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 <sub>2-e</sub> /TJ)	
		UAGp	CO <sub>2</sub>	CH <sub>4</sub>
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

Method 2 for fugitive emissions from natural gas distribution requires the use of equipment-specific emission factors and more detail on the types of equipment used at the facility. The Method is intended to be as specified in the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Natural Gas Industry 2009* sections 5 and 6.1.2. The option is also provided to refine the emission factors from information on the composition of the gases and from information on the leakage rates for specific pipeline materials for the industry.

(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<sub>2</sub>-e tonnes.

 $\Sigma_k$  is the total of emissions of gas type (*j*) measured in CO<sub>2</sub>-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<sub>2</sub>-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<sub>jk</sub>*, 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.

Note that 3.81 (2) (c) allows adjustment of emission factors for variations in the type of material from which the equipment is made. This adjustment is made using Table 5-3 and section 5.2.1 of the publication entitled Greenhouse Gas Emission Estimation Methodologies, Procedures and Guidelines for the Natural Gas Distribution Sector, American Gas Association, April 2008. Table 5-3 includes the emission factors for equipment made from different materials, for example, cast iron pipelines or plastic pipelines. Section 5.2.1 provides a description of how to apply the information in Table 5-3.

The publication entitled Greenhouse Gas Emission Estimation Methodologies, Procedures and Guidelines for the Natural Gas Distribution Sector, American Gas Association, April 2008, is available from:

http://www.aga.org/legislative/legislative+advocacy/environmentalinformation/publice nviro/2008/aga+greenhouse+gas+emission+estimation+guidelines+for+the+natural+ gas+distribution+sector.htm

### 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.

Note that in this part the definition of natural gas is as follows:

natural gas includes coal seam methane that is captured for combustion where

the production of coal is not intended to occur

### 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.

# Summary of available methods, for estimating emissions from natural gas production and processing (emissions that are vented or flared), by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Deliberate releases from pr	ocess vents, system up	osets and accidents	
Method 1	Section 3.84	Section 3.84	NO
Method 2	NA	NA	NO
Method 3	NA	NA	NO
Method 4	Method 4 under Part 1.3	Method 4 under Part 1.3	NO
Flaring			
Method 1	Section 3.85	Section 3.85	Section 3.85
Method 2	Section 3.86	NA	NA
Method 3	Section 3.87	NA	NA

NA = Not available. NO = Not occurring

# Subdivision 3.3.9.1—Fugitive emissions that result from deliberate releases from process vents, system upsets and accidents

Venting refers to emissions that are the result of processes or equipment design or operational practices. Venting at oil or gas processing facilities is mainly associated

with the release of  $CO_2$ , which is extracted from the raw gas stream in the course of gas processing. Because separation of the other components of the gas stream from the  $CO_2$  is incomplete, the vented  $CO_2$  contains small quantities of methane.

# 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

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

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

Method 1 is derived from the methods used for the *National Greenhouse Accounts*. Methods 2 and 3 for carbon dioxide rely on the sampling and analysis of the fuel to estimate the composition of the gases in the fuel in accordance with the provisions of chapter 2.

# 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<sub>2</sub>-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<sub>2</sub>-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 <sub>2</sub> -e/tonnes fuel flared)			
		CO <sub>2</sub>	CH <sub>4</sub>	$N_2O$	
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<sub>2</sub> from fuel type (*i*) flared in the natural gas production and processing during the year, measured in CO<sub>2</sub>-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<sub>2</sub> within the fuel type (*i*) in the natural gas production and processing during the year, measured in CO<sub>2</sub>-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<sub>2</sub>-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<sub>2</sub>-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*<sub>ij</sub>) must be determined in accordance with method 3 for the consumption of gaseous fuels as specified in Division 2.3.4.

#### Estimating Carbon dioxide emissions from natural gas production and

#### processing flaring using Method 2

Natural gas production and processing generally involves some flaring of a waste gas stream. In this example a facility flares a waste gas stream of 1,000 tonnes during the

year, which contains a relatively high content of carbon dioxide in addition to some hydrogen sulphide and hydrocarbons. The reporters have chosen to use method 2 as this approach provides the opportunity to develop a carbon dioxide emission factor that better reflects the hydrocarbons present in the gas stream, as well as account for the in-situ carbon dioxide quantity which is emitted, but not combusted in the flare.

Calculate the carbon dioxide emissions using Method 2 in section 3.86 of NGER (Measurement) Determination

$$E_{ico2} = (Q_h \times EF_h \times OF_i) + QCO_2$$

Where:

*Eico2* is the fugitive emissions of CO<sub>2</sub> from fuel type (i) flared in natural gas production and processing during the year, measured in CO<sub>2</sub>-e tonnes.

 $Q_h$  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.

 $QCO_2$  is the quantity of CO<sub>2</sub> within the fuel type (*i*) in natural gas production and processing during the year, measured in CO<sub>2</sub>-e tonnes in accordance with Division 2.3.3.

In this example it was determined (in accordance with Division 2.3.3) that the average composition of the waste gas stream being flared during the year is as follows:

Hydrocarbons C1 to C5 = 0.78 tonnes/ tonne of waste gas stream

Hydrogen sulphide = 0.0.04 tonnes/ tonne of waste gas stream

Nitrogen = 0.08 tonnes/ tonne of waste gas stream

Carbon dioxide = 0.10 tonnes/ tonne of waste gas stream

Therefore:

 $Q_h = 0.78 \times 1000$  t of waste gas stream flared during the year

 $Q_h = 780$  tonnes

 $QCO_2 = 0.10 \text{ x } 1000 \text{ t of waste gas stream flared during the year}$ 

#### *QCO*<sup>2</sup> = 100 tonnes

 $EF_h$  is the emission factor for the total hydrocarbons (h) within the fuel type (i) in natural gas production and processing during the year, measured in CO<sub>2</sub>-e tonnes per tonne of fuel type (i) flared, estimated in accordance with method 2 in Division 2.3.3.

In this example it was determined (in accordance with Division 2.3.3) that the emission factor derived from the average hydrocarbon composition of the waste gas stream being flared during the year was:

2.2 tonnes of CO<sub>2</sub> per tonne of waste gas stream flared

Therefore:

EFh = 2.2

 $OF_i$  is 0.98, which is the correction factor for the oxidation of fuel type (i) flared.

To calculate the CO<sub>2</sub> emissions from waste gas flared:

= (780 x 2.2 x 0.98) + 100 = 1,781.7

Therefore, the total emissions from the source = 1,782 tonnes

# Part 3.4—Carbon capture and storage—fugitive emissions

This part provides for the fugitive emissions of greenhouse gases from carbon capture and storage activities, where greenhouse gases are captured for permanent storage underground in geological formations

Any leakage or deliberate venting of greenhouse gas substances are a source of greenhouse gas emissions. Such fugitive emissions are considered to have the potential to occur at each of the 4 stages of the CCS process:

- Capture the separation of greenhouse gases from other gases produced at large industrial process facilities has the potential for process leaks from pipes and equipment.
- Transport compressed greenhouse gases transported by pipeline.
- Injection greenhouse gases are injected using drilling and well head techniques similar to those used in the natural gas industry gas extraction.
- Storage CCS is intended to provide permanent geological storage of injected greenhouse gases however there is a risk that stored greenhouse gases could subsequently leak from the storage formation to the atmosphere.

Division 1.2.3 in Chapter 1 sets out the requirements for facilities that captures the carbon dioxide - which may only deduct from their estimate of greenhouse gases generated the amount of greenhouse gas substances that are either transferred to a regulated underground geological storage site or, if there is no transfer, injected into the regulated underground geological storage site.

The fugitive emissions of greenhouse gases from their transport up until the point of transfer are accounted for in the emission estimate for the facility that generates greenhouse gases and undertakes the capture.

Part 3.4 allows the fugitive emissions from the transport of greenhouse gases captured from the point of transfer to the point of injection to be estimated.

### **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

Method 1 provides for a high level principles based approach, appropriate for use where monitoring data exists for the amount of greenhouse gas accepted into the transport system and the amount of greenhouse gas delivered to an injection operation – making it a matter of determining losses.

Where the monitoring arrangements of the project mean such an approach may not be practical, reporters may elect to apply an equipment level bottom up approach using Method 2 under section 3.77. This method is well established for the estimation of emissions from the transmission of natural gas, and is applied in relation to the greenhouse gas being transported for the purposes of CCS as if it were a type of natural gas.

### 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:

$$\mathbf{E}_{j} = \gamma_{j} \left( \mathbf{RCCS}_{j} - \mathbf{Q}_{inj} \right)$$

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<sub>2</sub>-e tonnes.

 $\gamma_j$  is the factor for converting a quantity of gas type (*j*) from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-e tonnes, being:

- (a) for methane— $6.784 \times 10^{-4} \times 21$ ; and
- (b) for carbon dioxide— $1.861 \times 10^{-3}$ ; 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.

### 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:

 $E_j$  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<sub>2</sub>-e tonnes.

 $\gamma_j$  is the factor for converting a quantity of gas type (*j*) from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-e tonnes, being:

- (a) for methane— $6.784 \times 10^{-4} \times 21$ ; and
- (b) for carbon dioxide— $1.861 \times 10^{-3}$ ; 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.

### **Division 3.4.3—Injection of greenhouse gases**

As the processes and technologies involved with greenhouse gas injection are considered comparable with those for natural gas extraction, Division 3.4.3 mirrors existing provisions for natural gas production, where carbon dioxide is often injected into reservoirs as part of the normal operational practice of gas extraction.

There is no Method 1, as there no appropriate default factors for CCS injection.

Fugitive leakage emissions may occur during the injection of captured greenhouse gases into geological storage from sources such as the unintentional equipment leaks from valves, flanges, pump seals, compressor seals, relief valves, sampling connections, process drains, open-ended lines, casing, tanks and other leakage sources from pressurised equipment not classed as a vent.

Venting refers to emissions that are the result of processes or equipment design or operational practices. Venting during the injection phase of CCS operations is mainly associated with the release of CO2, which is extracted from the raw gas stream in the course of gas processing. It may also include release from actions such as deliberate backflow venting of injection wells for maintenance.

### 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:

$$E_{ij} = \sum_{k} \left( Q_{ik} \times EF_{ijk} \right)$$

where:

 $EF_{ijk}$  is the emission factor (*j*) measured in CO<sub>2</sub>-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<sub>2</sub>-e tonnes.

 $\Sigma_k$  is the emissions (*j*) measured in CO<sub>2</sub>-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**

In Australia, a CCS project may only operate in accordance with approvals under one of a number of State and Commonwealth CCS legislative instruments. These instruments include:

- (a) the Offshore Petroleum and Greenhouse Gas Storage Act 2006 (Cwlth)
- (b) the Greenhouse Gas Geological Sequestration Act 2008 (Vic)
- (c) the Offshore Petroleum and Greenhouse Gas Storage Act 2010 (Vic)
- (d) the Greenhouse Gas Storage Act 2009 (Qld)
- (e) the Barrow Island Act 2003 (WA)
- (f) the Petroleum and Geothermal Energy Act 2000 (SA).

CCS legislation provides for the regulation of CCS activities in Australia, and deals with matters of licensing (including approvals processes, the setting of operational and performance conditions and compliance/enforcement mechanisms), resource and environmental protection and liabilities.

A key feature of these instruments is the inclusion of monitoring, reporting and verification requirements focused on the early identification of any deviation from expected behaviour of stored greenhouse gases modelled during project approval processes.

NGER reporting under 3.4.4 is expected to mirror monitoring and reporting of CCS storage formations undertaken for these existing regulatory purposes, and allows for its use in providing an estimate of leakage from storage formations.

### 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:

$$\mathbf{C}_{\mathrm{cst}} = \mathbf{C}_{\mathrm{ost}} + \mathbf{Q}_{\mathrm{inj}} - \mathbf{E}_{\mathrm{co}_2}$$

where:

 $C_{cst}$  is the closing stock of a stored greenhouse gas at the storage site for the reporting year, measured in CO<sub>2</sub>-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<sub>2</sub>-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<sub>2</sub>-e tonnes.

 $Q_{inj}$  is the quantity of a greenhouse gas injected into the geological formation during the reporting year, measured in CO<sub>2</sub>-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  $C_{ost}$  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  $E_{CO_2}$ , 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

Industrial process emissions are an important source of emissions in Australia and are generated from a wide variety of activities. The principal processes that lead to industrial process emissions include:

- 1. Mineral Products—generated mainly from the consumption (heating) of carbonate materials (such as limestone) and from within processes that generate carbon dioxide from the use of carbonates;
- Chemical Industry—generated mainly by the use of fuels as a feedstock or reductant;
- Metal Products—generated principally from the use of fuels such as coke as carbon reductants and also including perfluorocarbons released from aluminium metal production;
- 4. Synthetic gas emissions —the release of hydrofluorocarbons and sulphur hexafluoride either as fugitive emissions or leakages from the use of these gases as (for example) refrigerants.

Other sources of emissions released in the course of the production, such as from the combustion of fuels for energy, are not described in this chapter and must be estimated using the Methods described in other chapters.

Full details of industries covered in this chapter are given in section 4.1.

### 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

This Part applies to any industry that generates emissions of carbon dioxide through the consumption of carbonates such as calcium carbonate (limestone) or magnesium carbonate. The consumption of carbonates that does not lead to carbon dioxide emissions (for example, when used as gravel) is not covered by the scope of these Guidelines.

In order to deduct carbon dioxide captured for permanent storage reporters are required to use Method 2 or higher. These higher order methods provide a more accurate estimate of the carbon dioxide emissions than under Method 1, the default method. As the carbon dioxide captured is deducted from the emissions estimate it is necessary to have a greater level of accuracy in the emissions estimate than is achieved using Method 1.

### **Division 4.2.1—Cement clinker production**

Carbon dioxide is generated during the production of clinker, an intermediate product from which cement is made. The manufacture of cement involves a multi-stage process whereby calcium carbonate (CaCO<sub>3</sub>) from calcium rich raw materials such as limestone, chalk and natural cement rock is heated at temperatures of approximately 1500 °C in cement kilns to form lime (CaO) and CO<sub>2</sub>. In addition to CaCO<sub>3</sub>, the raw materials used in cement production may also contain small quantities of magnesium carbonate (MgCO<sub>3</sub>). On heating, MgCO<sub>3</sub> also decomposes to generate CO<sub>2</sub>. Some clinker manufacturers also use materials containing lime and magnesium oxide as inputs into their process which can reduce the amount of CO<sub>2</sub> generated by that facility.

It is intended that the parameters  $F_{cal}$  and  $F_{ckd}$  in methods 1, 2 and 3 in this division, be estimated by industry based on the principles of Section 1.13, namely transparency, comparability, accuracy and completeness. Where actual data for these is not available it is assumed that, at the temperatures and residence times achieved in cement (clinker) kilns, the degree of calcination achieved for all material incorporated in the clinker is 100 percent.

### 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.

Summary of available methods, for estimating emissions from cement production, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 4.4	NO	NO
Method 2	Section 4.5	NO	NO
Method 3	Section 4.8	NO	NO
Method 4	Part 1.3	NO	NO

NO = Not occurring

### 4.4 Method 1—cement clinker production

Method 1 for the production of cement clinker is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report.* It involves the collection of data on the quantities of cement clinker and cement kiln dust produced and the use of the specified emission factors for cement clinker and carbon-bearing non-fuel raw material.

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<sub>2</sub>-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.

Fckd 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

Method 2 requires the derivation of more accurate, facility-specific emission factors to generate more accurate estimates of emissions of carbon dioxide from the production process. It utilises sampling and analysis of the clinker outputs to estimate the composition of its contents and, from an understanding of the chemical reactions involved in the calcination, the derivation of facility-specific emission factors. The fractions of calcium oxide and magnesium oxide in subsection (2) should not include the calcium oxide and magnesium oxide that enters the process in the raw materials.

(1) Method 2 is:

$$\mathbf{E}_{ij} = \left(\mathbf{E}\mathbf{F}_{ij} + \mathbf{E}\mathbf{F}_{toc,j}\right) \times \left(\mathbf{A}_{i} + \mathbf{A}_{ckd} \times \mathbf{F}_{ckd}\right) - \gamma \mathbf{RCCS}_{co_{2}}$$

where:

 $E_{ij}$  is the emissions of carbon dioxide (*j*) released from the production of cement clinker (*i*) during the year measured in CO<sub>2</sub>-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.

Fckd 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.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-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.

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Note: An appropriate standard is AS 4264.4—1996, Coal and coke – Sampling Part 4: Determination of precision and bias.
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(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

Method 3 is based on the Tier 3 approach in the *2006 IPCC Guidelines for National Greenhouse Inventories* which utilises information on the purity of the carbonate inputs. This method requires sampling and analysis of the raw materials to determine the qualities that affect emission levels such as the raw material's pure carbonate content.

- (1) Method 3 is:
  - Step 1 Measure the amount of emissions of carbon dioxide in CO<sub>2</sub>-e tonnes released from each pure carbonate calcined in the production of cement clinker during the year as follows:

$$\mathbf{E}_{ij} = \left(\mathbf{E}\mathbf{F}_{ij} \times \mathbf{Q}_{i} \times \mathbf{F}_{cal}\right) - \mathbf{A}_{ckd} \times \mathbf{E}\mathbf{F}_{ckd} \times \left(1 - \mathbf{F}_{ckd}\right) + \mathbf{Q}_{toc} \times \mathbf{E}\mathbf{F}_{toc} - \gamma \mathbf{RCCS}_{co}$$

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<sub>2</sub>-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.

#### Fcal 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<sub>ckd</sub> 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.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-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<sub>2</sub>-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

- 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**

Lime is a chemical having major uses in metallurgy and construction. Lime is produced by heating carbonate raw materials in a kiln. During this process, carbon dioxide is emitted.

Lime kiln dust may be produced as part of the lime production process and can be recycled through the system. However at the end of the process some lime kiln dust may still remain. The quantity of kiln dust produced impacts on the emissions estimate and is included as part of the method,

Emissions from the in-house production of lime in the metals industry is estimated under Division 4.2.3.

### 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.

Summary of available methods, for estimating emissions from lime production, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 4.13	NO	NO
Method 2	Section 4.14	NO	NO
Method 3	Section 4.17	NO	NO
Method 4	Part 1.3	NO	NO

NO = Not occurring

### 4.13 Method 1—lime production

Method 1 for the production of lime is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*. It involves the multiplication of the quantity of lime produced by the emission factor for lime.

Lime kiln dust may be produced as part of the lime production process and can be recycled through the system. However at the end of the process some lime kiln dust may still remain. The quantity of kiln dust produced impacts on the emissions estimate and is included as part of the method,

Lime is also produced using varying grades of limestone which contain impurities such as Magnesium Oxide (MgO). For Method 1 estimation, default emission factors have been provided for lime produced using limestone with higher concentrations of MgO.

(1) Method 1 is:

 $\mathbf{E}_{ij} = \left(\mathbf{A}_{i} + \mathbf{A}_{lkd} \times \mathbf{F}_{lkd}\right) \times \mathbf{E}\mathbf{F}_{ij}$ 

where:

 $E_{ij}$  is the emissions of carbon dioxide (*j*) released from the production of lime (*i*) during the year, measured in CO<sub>2</sub>-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.

Fikd 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

Method 2 requires the derivation of more accurate, facility-specific emission factors to generate more accurate estimates of emissions of carbon dioxide from the production process. It utilises sampling and analysis of the lime outputs to estimate the composition of its contents and, from an understanding of the chemical reactions involved in the consumption of carbonate (calcination), the derivation of facility-specific emission factors.

(1) Method 2 is:

$$\mathbf{E}_{ij} = (\mathbf{A}_{i} + \mathbf{A}_{lkd} \times \mathbf{F}_{lkd}) \times \mathbf{E}\mathbf{F}_{ij} - \gamma \mathbf{RCCS}_{co_2}$$

where:

 $E_{ij}$  is the emissions of carbon dioxide (*j*) released from the production of lime (*i*) during the year, measured in CO<sub>2</sub>-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<sub>lkd</sub> 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:

 $EF_{ii} = F_{CaO} \times 0.785 + F_{MgO} \times 1.092$ 

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.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-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

Method 3 is based on the Tier 3 approach in the IPCC Guidelines for National Greenhouse Inventories which utilises information on the purity of the carbonate inputs. This method requires sampling and analysis of the raw materials for qualities that affect emission levels such as the material's pure carbonate content.

- (1) Method 3 is:
  - Step 1 Measure the amount of emissions of carbon dioxide in CO<sub>2</sub>-e tonnes released from each pure carbonate calcined in the production of lime during the year as follows:

 $\mathbf{E}_{ij} = (\mathbf{E}\mathbf{F}_{ij} \times \mathbf{Q}_i \times \mathbf{F}_{cal}) - \mathbf{A}_{lkd} \times \mathbf{E}\mathbf{F}_{lkd} \times (1 - \mathbf{F}_{lkd}) - \gamma \mathbf{RCCS}_{co_2}$ where:

 $E_{ij}$  is the emissions of carbon dioxide (*j*) released from a carbonate (*i*) calcined in the production of lime during the year measured in CO<sub>2</sub>-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.

Fcal 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**<sub>lkd</sub> 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.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-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

This division is concerned with the consumption or any other use of carbonates that generates carbon dioxide emissions regardless of the industry in which they are used. Apart from the production of cement clinker and lime, addressed in Divisions 4.2.1 and 4.2.2, and soda ash, addressed in Division 4.2.4, activities that may be likely to use carbonates that generate emissions include the industries listed in Section 4.20.

Another process where limestone is consumed is the production of phosphoric acid from phosphate rock using the 'wet process'. The carbon dioxide emissions result from a secondary reaction in which limestone present in the phosphate rock reacts with the acid. The emissions associated with the consumption of limestone during phosphoric acid production should be reported under this division. The quantity of limestone in the phosphate rock must be known to apply the methods outlined in this Division.

#### 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.

## Summary of available methods, for estimating emissions from other uses of carbonates, by emissions of gas type $(\mathbf{j})$

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 4.22	NO	NO
Method 2	NA	NO	NO
Method 3	Section 4.23	NO	NO
Method 4	Part 1.3	NO	NO

NA = Not available. NO = Not occurring

#### 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:

 $E_{ij}$  is the emissions of carbon dioxide (*j*) released from raw carbonate material (*i*) consumed in the industrial process during the year measured in CO<sub>2</sub>-e tonnes.

 $Q_i$  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.

 $EF_{ij}$  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.

#### Fcal 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<sub>2</sub>-e tonnes, using the following formula:

 $E_j = Q_j \times ICC_j \times 3.664$ 

where:

 $E_i$  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<sub>2</sub>-e tonnes.

 $Q_i$  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	$6.068 \times 10^{-3}$
2	Victoria	$2.333 \times 10^{-4}$
3	Queensland	$2.509 \times 10^{-3}$
4	Western Australia	$3.140 \times 10^{-4}$
5	South Australia	$5.170 \times 10^{-4}$
6	Tasmania	$1.050 \times 10^{-3}$
7	Australian Capital Territory	$6.068 \times 10^{-3}$
8	Northern Territory	$5.170 \times 10^{-4}$

#### 4.23 Method 3—product other than cement clinker, lime or soda ash

Method 3 is based on the Tier 3 approach in the IPCC Guidelines for National Greenhouse Inventories which utilises information on the purity of the carbonate inputs. This method requires sampling and analysis of the raw materials to determine the material's pure carbonate content, which is then used in the estimation. This estimation differs from Method 1, which utilises raw carbonate material with specified degrees of impurity as an input into the estimation.

(1) Method 3 is:

1

Step 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:

$$\mathbf{E}_{ij} = \mathbf{E}\mathbf{F}_{ij} \times \mathbf{Q}_i \times \mathbf{F}_{cal} - \gamma \mathbf{RCCS}_{co_2}$$

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<sub>2</sub>-e tonnes.

 $EF_{ii}$  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.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-e tonnes.

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

- Step Add together the amount of emissions of carbon dioxide for each
- 2 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 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<sub>2</sub>-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.

 $\gamma$  is the factor 1.861  $\times$  10<sup>-3</sup> for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-e tonnes.

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

- Step Identify the amount of emissions of carbon dioxide for each clay
   material consumed in the industrial process during the reporting year.
- Step Add together each amount identified under step 2.

3

#### 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

This Division addresses emissions from the consumption and also from the production of soda ash. The consumption of soda ash generates carbon dioxide emissions regardless of the industry that consumes the product. Examples of industries that use soda ash are given in Section 4.26.

#### 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.

Summary of available methods, for estimating emissions from soda ash use, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 4.29	NO	NO
Methods 2, 3 and 4	NA	NO	NO

NA = not available. NO = Not occurring

#### 4.29 Method 1—use of soda ash

This Method is derived from the methodology used for the National Greenhouse Accounts. It involves the multiplication of the quantity of soda ash consumed in the production process by the emission factor for 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<sub>2</sub>-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

Emissions from soda ash production arise from the consumption of fuels for energy and from the calcination of limestone and sodium bicarbonate. The production of soda ash is a multi-step process involving the generation and reabsorption of carbon dioxide. To obtain a more accurate estimation of emissions from the consumption of fuels and calcination processes a carbon balance approach is taken.

#### 4.30 Available methods

- 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.

Summary of available methods, for estimating emissions from soda ash production, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 4.31	Section 4.31	Section 4.31
Method 2	Section 4.32	NA	NA
Method 3	Section 4.33	NA	NA
Method 4	Part 1.3	NA	NA

NA = Not available

#### 4.31 Method 1—production of soda ash

Method 1 is:

- Step Calculate the carbon content in fuel type (i) or carbonate material (j)
- 1 delivered for the activity during the year measured in tonnes of carbon as follows:

$$\boldsymbol{\Sigma}_{i} \ CCF_{i} \ \boldsymbol{\times} \boldsymbol{Q}_{i} \ + \boldsymbol{\Sigma}_{j} \ CCF_{j} \boldsymbol{\times} F_{j} \boldsymbol{\times} \boldsymbol{L}_{j}$$

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 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 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:

$$\sum_{r} CCF_{r} \times F_{r} \times Y_{r}$$

where:

 $\Sigma_r$  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 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:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta s_{qi}$  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.

 $\Sigma_j$  has the same meaning as in step 1.

*CCF<sub>j</sub>* has the same meaning as in step 1.

 $\Delta S_{qj}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta s_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

 $CCF_r$  has the same meaning as in step 3.

 $\Delta S_{yr}$  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<sub>2-</sub>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.

 $\sum_{i}$  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:

 $\sum_{p} CCF_{p} \times A_{p}$ 

where:

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

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

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

Step 3 Calculate the carbon content in waste by-product types (*r*) leaving the activity, other than as an emission of greenhouse gas, during the year, measured in tonnes of carbon, as follows:

$$\sum_{\mathbf{r}} \mathbf{CCF}_{\mathbf{r}} \times \mathbf{Y}_{\mathbf{r}}$$

where:

 $\Sigma_r$  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:

 $\Sigma_{i} \ CCF_{i} \times \Delta S_{qi} + \Sigma_{j} \ CCF_{j} \times \Delta S_{qj} + \Sigma_{p} \ CCF_{p} \times \Delta S_{ap} + \Sigma_{r} \ CCF_{r} \times \Delta S_{yr} + \alpha \gamma RCCS_{_{CO2}}$ 

where:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta s_{qi}$  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.

 $\Sigma_j$  has the same meaning as in step 1.

*CCF*<sup>*j*</sup> has the same meaning as in step 1.

 $\Delta S_{qj}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta Sap$  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.

 $\Sigma_r$  has the same meaning as in step 3.

*CCF*<sup>*r*</sup> has the same meaning as in step 3.

 $\Delta s_{yr}$  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.

 $\alpha$  is the factor <sup>3.664</sup> for converting the mass of carbon dioxide to a mass of carbon.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO2-e tonnes.

*RCCS<sub>CO2</sub>* 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<sub>2</sub>-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

This Division sets out how 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 purpose of working out the emissions released from the consumption and production of carbonates.

Division 4.2.5 specifies the criteria for the estimation of the amounts of carbonate consumed or produced during the operation of a facility during a year.

There are four criteria available for the estimation of the quantities of carbonates reflecting differing levels of measurement effort and precision.

Under the National Greenhouse and Energy Reporting Regulations 2008, the criterion chosen by the Reporter to estimate carbonate inputs and outputs is required to be reported. Measuring equipment calibrated to a measurement requirement mentioned in Sections 4.37 and 4.38 refers to the standards required for measurement to support all commercial transactions covered by the National Measurement Act 1960 and associated instruments.

In Section 4.37 it is intended that measured data for carbonates delivered (at the point of sale) would also meet the Criterion AAA under certain circumstances. These circumstances are that stocks of the carbonate consumed at the facility are less than 5% of carbonate consumption for the facility during the year and that the stock changes by less than 1% during the year. It is intended that the analysis may be conducted by the supplier.

The simplified measurement of consumption criterion is available in those cases where the Reporter does not purchase their carbonates and where the Reporter also does not have metering equipment installed that meets the requirements of criterion AAA. In these cases, it is intended that Reporters should estimate consumption using metering devices or measurement techniques in practice in the industry. Such measurements would need to meet the criteria set out in section 1.13 of transparency, comparability, accuracy and completeness. Such data would be classified and reported as 'BBB' data. The restriction on the choice of criteria at 4.35 (3) is designed to ensure time series consistency of the measurements.

- (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

This Part applies to any chemical industry that generates emissions of carbon dioxide through the use of fuels as feedstocks or as carbon reductants, as described below. Nitric acid production is also addressed in this chapter.

It is intended that the quantities of fuels consumed for industrial process purposes are to be estimated in accordance with the same criteria as has been set out for fuels consumption in Chapter 2.

Other sources of emissions arising from the production of the products listed below, such as from the combustion of fuels for energy purposes, are not described in this chapter and must be estimated using the Methods described in other chapters.

## **Division 4.3.1—Ammonia production**

Ammonia production involves the consumption of fossil fuel for both energy and nonenergy purposes. CO<sub>2</sub> emissions are generated in the primary steam reforming process in which the source of fuel, commonly natural gas, is used to derive hydrogen.

Emissions from the use of natural gas for its energy value should be separated from its non-energy purposes, if possible. Emissions and fuels consumed for energy should be estimated using Methods provided under Chapter 2. Emissions and fuel use as an input into ammonia production should be estimated using Methods provided in this Division. If this separation cannot be completed then, in order to minimise the risk of duplication or omission, all emissions from the use of gas in ammonia production should be included within the industrial processes sector using methods detailed in this Division.

In order to deduct carbon dioxide captured for permanent storage reporters are required to use Method 2 or higher. These higher order methods provide a more accurate estimate of the carbon dioxide emissions than under Method 1, the default method. As the carbon dioxide captured is deducted from the emissions estimate it is necessary to have a greater level of accuracy in the emissions estimate than is achieved using Method 1.

#### 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.

## Summary of available methods, for estimating emissions from ammonia production, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 4.42	NO	NO
Method 2	Section 4.43	NO	NO
Method 3	Section 4.44	NO	NO
Method 4	Method 4 under Part 1.3.	NO	NO

NO = Not occurring.

#### 4.42 Method 1—ammonia production

Method 1 for emissions of carbon dioxide released from the use of fuels as feedstocks in the production of ammonia is derived from the methodology used for the *National Greenhouse Accounts*.

(1) Method 1 is:

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

where:

 $E_{ij}$  is the emissions of carbon dioxide released from the production of ammonia during the year measured in CO<sub>2</sub>-e tonnes.

 $Q_i$  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.

 $EC_i$  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.

 $EF_{ij}$  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.

 $\boldsymbol{R}$  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  $\boldsymbol{R}$  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:

$$\mathbf{E}_{ij} = \frac{\mathbf{Q}_i \times \mathbf{E}\mathbf{C}_i \times \mathbf{E}\mathbf{F}_{ij}}{1\ 000} - \mathbf{R} - \gamma \mathbf{RCCS}_{co_2}$$

where:

 $E_{ij}$  is the emissions of carbon dioxide released from the production of ammonia during the year measured in CO<sub>2</sub>-e tonnes.

 $Q_i$  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.

 $EC_i$  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.

 $EF_{ij}$  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.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-e tonnes.

 $RCCS_{CO_2}$  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  $EF_{ij}$ .
- (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  $EF_{ij}$ .

## **Division 4.3.2—Nitric acid production**

The manufacture of nitric acid ( $HNO_3$ ) generates nitrous oxide ( $N_2O$ ) as a by-product of the high temperature catalytic oxidation of ammonia ( $NH_3$ ).

#### 4.45 Application

This Division applies to chemical industry nitric acid production.

#### 4.46 Available methods

Method 1, 2 or 4 are available for plants, unless abatement measures are in place – in which case Method 2 or 4 must be used.

- (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.

## Summary of available methods, for estimating emissions from nitric acid production, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	NO	NO	Section 4.47
Method 2	NO	NO	Section 4.48
Method 3	NO	NO	NA
Method 4	NO	NO	Method 4 under Part 1.3

NO = Not occurring, NA = Not available.

#### 4.47 Method 1—nitric acid production

Method 1 for emissions released from the production of nitric acid (is derived from the methodology used for the *National Greenhouse Accounts*, with the emission factors for individual plants taken from the *IPCC Guidelines for National Greenhouse Inventories Volume 3, Part 1*.

(1) Method 1 is:

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

where:

 $E_{ijk}$  is the emissions of nitrous oxide released during the year from the production of nitric acid at plant type (k) measured in CO<sub>2</sub>-e tonnes.

 $EF_{ijk}$  is the emission factor of nitrous oxide for each tonne of nitric acid produced during the year from plant type (k).

 $A_{ik}$  is the quantity, measured in tonnes, of nitric acid produced during the year from plant type (k).

(2) For  $EF_{ijk}$  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 <sub>2</sub> -e per tonne of nitric acid production)
1	Atmospheric pressure plants	1.49
2	Medium pressure combustion plant	2.09
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.

**Example:** A high pressure nitric acid plant produces 45,000 tonnes of nitric acid during the year. The Reporter elects to use Method 1 (*Division 4.3.2*) for each of

greenhouse emission gases (j) (nitrous oxide) to calculate the Industrial Process emissions. Emissions are estimated as follows:

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

where:

 $E_{ijk}$  is the emissions of nitrous oxide released during the year from the production of nitric acid at the plant type (k) measured in CO<sub>2</sub> e tonnes.

 $EF_{ijk}$  is the emission factor of nitrous oxide for each tonne of nitric acid produced during the year from plant type (k). In this case the emission factor is 2.68 tonnes CO<sub>2</sub>-e per tonne of nitric acid production for a high pressure plant.

 $A_{ik}$  is the quantity, measured in tonnes, of nitric acid produced during the year from plant type (k). In this case production is 45,000 tonnes.

Therefore, to estimate emissions of nitrous oxide in CO<sub>2</sub>-e tonnes:

=45,000 x 2.68

Total emissions of nitrous oxide  $= 120,600 \text{ t CO}_2\text{-e}$ 

#### 4.48 Method 2—nitric acid production

For Method 2, facility-specific emission factors may be derived from periodic emissions monitoring undertaken in accordance with the provisions of Chapter 1 (and, in particular, section 1.28). These facility-specific emission factors should be substituted into the equation specified in 4.47 (1) to estimate emissions.

- (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  $EF_{ijk}$ :
  - (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<sub>2</sub>-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**

Method 1 for emissions released from the production of adipic acid is described in *IPCC 2006 Guidelines for National Greenhouse Gas Inventories Volume 3, Part 1*. Currently, there is no adipic acid production recorded in Australia.

#### 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**

Method 1 for emissions released from the production of carbide is described in *IPCC 2006 Guidelines for National Greenhouse Gas Inventories Volume 3, Part 1.* Currently, there is no carbide production recorded in Australia.

#### 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

Emissions of carbon dioxide released from the use of fuels as carbon reductants or carbon anodes in the production of chemical or mineral products (other than carbide) should be estimated using methods provided in this Division. The use of fuels for energy purposes should be estimated using methods in Chapter 2 and reported separately.

Some of the industries included in this Division are listed below.

In order to deduct carbon dioxide captured for permanent storage reporters are required to use Method 2 or higher. These higher order methods provide a more accurate estimate of the carbon dioxide emissions than under Method 1, the default method. As the carbon dioxide captured is deducted from the emissions estimate it is necessary to have a greater level of accuracy in the emissions estimate than is achieved using Method 1.

#### 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.

## Summary of available methods, for estimating emissions from titanium dioxide production, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 4.55	NO	NO
Method 2	Section 4.56	NO	NO
Method 3	Section 4.57	NO	NO
Method 4	Part 1.3	NO	NO

NO = Not occurring.

# 4.55 Method 1—chemical or mineral production, other than carbide production, using a carbon reductant or carbon anode

Method 1 for emissions of carbon dioxide released from the use of fuels as carbon reductants or carbon anodes in the production of a chemical or mineral product is derived from the methodology used for the *National Greenhouse Accounts*.

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:

 $\Sigma_i$  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:

 $\Sigma_p$  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:

$$\Sigma_{\rm r} \ {\rm CCF_r} \ \times \ {\rm Y_r}$$

where:

 $\Sigma_r$  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:

$$\boldsymbol{\Sigma_{i}} \ \mathbf{CCF_{i}} \times \Delta \mathbf{S_{qi}} + \boldsymbol{\Sigma_{p}} \ \mathbf{CCF_{p}} \times \Delta \mathbf{S_{ap}} + \boldsymbol{\Sigma_{r}} \ \mathbf{CCF_{r}} \times \Delta \mathbf{S_{yr}}$$
where:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

 $CCF_r$  has the same meaning as in step 3.

 $\Delta S_{yr}$  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<sub>2</sub>-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:

 $\sum_{i} CCF_{i} \times \Delta S_{qi} + \sum_{p} CCF_{p} \times \Delta S_{ap} + \sum_{r} CCF_{r} \times \Delta S_{yr} + \alpha \gamma RCCS_{co_{2}}$ 

where:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

 $CCF_r$  has the same meaning as in step 3.

 $\Delta S_{yr}$  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.

 $\alpha$  is the factor <sup>3.664</sup> for converting the mass of carbon dioxide to a mass of carbon.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-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

This Part applies to any metal industry that generates emissions of carbon dioxide through the use of fuels as carbon reductants, as described below. Perfluorocarbon emissions from aluminium production are also addressed in this part.

The quantities of fuels consumed for industrial process purposes should be estimated in accordance with the same criteria as has been set out for fuels consumption in Chapter 2.

Other sources of emissions arising from the production of the products listed below, such as from the combustion of fuels for energy, are not described in this chapter and must be estimated using the Methods described in other chapters.

## Division 4.4.1—Iron, steel or other metal production using an integrated metalworks

This division applies to any facility that produces iron, steel or any metals produced using an integrated metalworks. Metals such as iron, steel, lead and silicon may be produced in an integrated metalworks where the metal and coke is produced on the same site. In this case it is difficult to identify emissions attributable to each part of the production process. In this case, emissions are estimated from the activity as a whole by estimating the inputs and outputs. The methods for estimating emissions of carbon dioxide are based on a carbon balance approach reducing the complexity of the calculation for these facilities.

Steel, in particular, is also produced using an electric arc furnace (EAF) or similar process. While not considered an integrated metalworks, emissions from iron or steel production using an EAF are to be estimated and reported within Division 4.4.1.

In order to deduct carbon dioxide captured for permanent storage reporters are required to use Method 2 or higher. These higher order methods provide a more accurate estimate of the carbon dioxide emissions than under Method 1, the default method. As the carbon dioxide captured is deducted from the emissions estimate it is necessary to have a greater level of accuracy in the emissions estimate than is achieved using Method 1.

Note that emissions from limestone and dolomite use in Iron and Steel production are to be reported under Division 4.2.3 'Use of carbonates for the production of a product other than cement clinker, lime or soda ash'.

## 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.

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 4.66	NO	NO
Method 2	Section 4.67	NO	NO
Method 3	Section 4.68	NO	NO
Method 4	Method 4 under Part 1.3	NO	NO

Summary of available methods, for estimating emissions from iron and steel production, by emissions of gas type (j)

NA = Not available. NO = Not occurring.

## 4.66 Method 1—production of a metal from an integrated metalworks

Method 1 sets out the estimation of emissions from a facility producing both a metal and coke. It specifies that emissions should be estimated using a carbon mass balance approach for the facility as a whole. Method 1 utilises carbon content factors listed in Appendix A (Schedule 3 in the Determination). These carbon content factors are derived directly from the carbon dioxide emission factors listed in Chapter 2. There are no carbon content factors specified for products or for waste by-products. It is intended that these should be estimated by industry based on the principles of Section 1.13, namely transparency, comparability, accuracy and completeness.

The carbon mass balance approach requires fuels to be estimated based on quantities of fuels delivered rather than consumed. Criteria AA or AAA cannot be utilised as changes in stocks of fuels are explicitly taken into account in the mass balance estimation directly.

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:

 $\Sigma_i$  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.

 $Q_i$  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 criterion A in Divisions 2.2.5, 2.3.6, 2.4.6 and 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:

$$\Sigma_p \operatorname{CCF}_p \times A_p$$

where:

 $\Sigma_p$  means sum the carbon content values obtained for all product types (*p*). *CCF*<sub>p</sub> 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:

$$\Sigma_r \operatorname{CCFr} \times \operatorname{Yr}$$

where:

 $\Sigma_r$  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:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

 $CCF_r$  has the same meaning as in step 3.

 $\Delta S_{yr}$  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<sub>2</sub>-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:

 $\sum_{i} CCF_{i} \times \Delta S_{qi} + \sum_{p} CCF_{p} \times \Delta S_{ap} + \sum_{r} CCF_{r} \times \Delta S_{yr} + \alpha \gamma RCCS_{co_{2}}$ 

where:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

 $CCF_r$  has the same meaning as in step 3.

 $\Delta S_{yr}$  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.

 $\alpha$  is the factor <sup>3.664</sup> for converting the mass of carbon dioxide to a mass of carbon.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-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:

## Estimating emissions from iron and steel production

Iron and Steel production can involve integrated processes such as coke making and steel furnace operations within a facility. The complex carbon and energy flows within the integrated facility can make the estimation of total emissions difficult to estimate when a bottom-up approach is taken. The carbon mass balance provides a top-down approach that simplifies the emission estimation process in this case, allowing the emissions to be estimated as a whole, while taking into account the carbon input and outputs to the facility as well as stockpile changes.

An emission estimation example using the method 1 carbon balance approach is provided below. The example is of an integrated iron and steel facility that uses coke oven coke, coking coal and fuel oil to produce coke, iron and then steel. The facility also produces coal tar and waste containing carbon, in addition to experiencing fuel stock changes during the year. The relevant data for the integrated iron and steel facility is outlined in the table below.

Data inputs for integrated iron and steel carbon balance example.				
Fuel or product type	Fuels delivered during the year	Products produced and leaving the activity during the year	Change (increase) in stocks during the year	Carbon content factor (CCF)
Coke oven coke		60,000 tonnes	-5,000 tonnes	0.789
Coking coal	750,000 tonnes		3,000 tonnes	0.752
Fuel oil	3,000 kilolitres			0.797
Coal tar		15,000 tonnes	200 tonnes	0.837
Crude steel		920,000 tonnes	1,000 tonnes	0.0017

Step 1 Calculate the carbon content in fuel types (i) or carbonaceous input material delivered for the activity during the year measured in tonnes of carbon as follows:

Where:

## $\Sigma_i CCF_i \times Q_i$

 $CCF_i$  is the carbon content factor mentioned in Appendix A 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.

The Method 1 default carbon content factors can be found in Schedule 3 of the NGER (Measurement) Determination and are shown in the table above.

 $Q_i$  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 Division 2.2.5, 2.3.6 and 2.4.6. In this case the quantities of input materials are shown in the table above.

#### To calculate the carbon content for the input materials:

Carbon content of coking coal =  $(750,000 \times 0.752) = 564,000$  tonnes of carbon

Carbon content of fuel oil =  $(3,000 \times 0.797) = 2,391$  tonnes of carbon

### **Therefore, total carbon** = (564,000 + 2,391) = **566,391 tonnes**

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

Where:

## $\Sigma_p \operatorname{CCF}_p \times A_p$

 $CCF_p$  is the carbon content factor measured in tonnes of carbon for each tonne of product type (p) produced during the year. In this case the carbon content factor of each product type is shown in the table above:

 $A_p$  is the quantity of product types (p) produced leaving the activity during the year measured in tonnes. In this case the quantity of product are shown in the table above:

To calculate the carbon content for the products leaving the activity during the year:

Carbon Content of crude steel=  $(920,000 \times 0.0017) = 1,564$  tonnes of carbon

Carbon Content of coke oven  $coke = (60,000 \times 0.789) = 47,340$  tonnes of carbon

Carbon Content of coal tar =  $(15,000 \times 0.837) = 12,555$  tonnes of carbon

**Therefore, total carbon** = (1,564 + 47,340 + 12,555) = **61,459 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:

Where:

## $\Sigma_r \operatorname{CCFr} \times \operatorname{Yr}$

 $CCF_r$  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. In this case the quantities of waste by-products are;

- slag, of which 230,000 tonnes was produced. The facility estimated the carbon content of the slag was 0.0005 tonnes per tonne of slag.
- Other non oxidised carbon sources estimated in accordance with the NGER (Measurement) Determination as being 1500 tonnes.

To calculate the carbon content for the waste products leaving the activity during the year:

Carbon Content of slag =  $(230,000 \times 0.0005) = 115$  tonnes of carbon

Carbon Content of other non oxidised carbon = 1500 tonnes of carbon

**Therefore, total carbon** = (115 + 1,500) **= 1,615 tonnes** 

Step 4 Calculate the carbon content in the amount of the increase in stocks of inputs, products and waste by products held within the boundary of the activity during the year in tonnes of carbon as follows:

Where:

$$\Sigma_{i} \operatorname{CCF_{i}} \times \Delta S_{qi} + \Sigma_{p} \operatorname{CCF_{p}} \times \Delta S_{ap} + \Sigma_{r} \operatorname{CCF_{r}} \times \Delta S_{yr}$$

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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. In this case the quantities of increases in stocks are shown in the table above:

## To calculate the carbon content for increase of fuel types

Carbon content of coke oven  $coke = (-5000 \times 0.789) = -3945$  tonnes of carbon

Carbon content of coking coal =  $(3000 \times 0.752) = 2256$  tonnes of carbon

#### **Therefore, total carbon** = (-3945 + 2256) **= -1689 tonnes**

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  is the increase in stocks of product types (p) produced by the activity and held within the boundary of the activity during the year measured in tonnes. In this case the quantities of product types shown in the table above:

#### To calculate the carbon content for increase in stock of product type:

Carbon content of coal tar =  $(200 \times 0.837) = 167.4$  tonnes of carbon

Carbon content of crude steel =  $(1000 \times 0.0017) = 1.7$  tonnes of carbon

**Therefore, total carbon** = (167.4 + 1.7) **= 169.1 tonnes** 

*CCF*<sup>*r*</sup> has the same meaning as in step 3.

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

There was no change in waste product stock produced and held during the year.

To calculate the total carbon contained in the change of stock:

Carbon content of increase in fuel types = -1689 tonnes

Carbon content of increase in product types = 169.1 tonnes

Carbon content of increase in waste by-products = 0 tonnes

**Therefore, total carbon** = (-1689 + 169.1 + 0) = -1519.9 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);

In this case A is:

= 61,459 + 1,615 + -1,519.9

= 61,554.1 tonnes of carbon

(b) subtract amount A from the amount worked out under step 1 to work out a new amount (amount B);

In this case:

= 504,836.9 tonnes of carbon

(c) multiply amount B by 3.664 to work out the amount of emissions released from the operation of the activity during a year.

= 504,836.9 x 3.664

= 1,849,722.4016 tonnes CO<sub>2</sub>-e

Therefore, total carbon balance CO<sub>2</sub> emissions from the source = 1,849,722 tonnes

## **Division 4.4.2—Ferroalloys production**

Emissions of  $CO_2$  occur during ferroalloy production as a result of the use of carbon reductants such as coke and the oxidation of a fossil fuel electrode.

## 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.

Methane and nitrous oxide emissions arising from the combustion of reductants should be estimated using methods described in Chapter 2 – Fuel Combustion.

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 4.71	NO	NO
Method 2	Section 4.72	NO	NO
Method 3	Section 4.73	NO	NO
Method 4	Method 4 under Part 1.3	NO	NO

Summary of available methods, for estimating emissions from ferroalloy metal production, by emissions of gas type (j)

NO = Not occurring.

#### 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:

 $\Sigma_i$  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 and 2.4.6; 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:

 $\Sigma_p$  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:

$$\Sigma_{\rm r} CCF_{\rm r} \times Y_{\rm r}$$

where:

 $\Sigma_r$  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:

$$\Sigma_{_{\mathrm{i}}} \ \mathrm{CCF}_{_{\mathrm{i}}} imes \Delta \mathrm{S}_{_{\mathrm{q}i}} + \Sigma_{_{\mathrm{p}}} \ \mathrm{CCF}_{_{\mathrm{p}}} imes \Delta \mathrm{S}_{_{\mathrm{ap}}} + \Sigma_{_{\mathrm{r}}} \ \mathrm{CCF}_{_{\mathrm{r}}} imes \Delta \mathrm{S}_{_{\mathrm{yr}}}$$

where:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

 $CCF_r$  has the same meaning as in step 3.

 $\Delta S_{yr}$  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<sub>2</sub>-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:

 $\Sigma_{i} \quad CCF_{i} \ \times \ \Delta S_{qi} + \Sigma_{p} \ CCF_{p} \ \times \ \Delta S_{ap} + \Sigma_{r} \ CCF_{r} \ \times \ \Delta S_{yr} + \alpha \ \gamma RCCS_{co_{2}}$ 

where:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

 $CCF_r$  has the same meaning as in step 3.

 $\Delta S_{yr}$  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.

 $\alpha$  is the factor <sup>3.664</sup> for converting the mass of carbon dioxide to a mass of carbon.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-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

Method 1 for carbon dioxide emissions from aluminium production is intended to reproduce the method set out in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, which is drawn from the *International Aluminium Institute Greenhouse Gas Protocol*. As for fuels combusted for energy, Methods 2 and 3 for the category provide for sampling and analysis of fuels in accordance with Chapter 2 to determine facility-specific carbon content factors to be applied in estimating emissions.

## 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.

Available methods, for estimating emissions from aluminium involving the consumption of baked carbon anodes, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 4.76	NO	NO
Method 2	Section 4.77	NO	NO
Method 3	Section 4.78	NO	NO
Method 4	Method 4 under Part 1.3	NO	NO

NA = Not available. NO = Not occurring.

### 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<sub>2</sub>-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<sub>2</sub>-e tonnes for each tonne of aluminium produced during the year, estimated in accordance with the following formula:

$$\mathrm{EF}_{\mathrm{ij}} = \mathrm{NAC} \times \left(\frac{100 - \mathrm{S}_{\mathrm{a}} - \mathrm{Ash}_{\mathrm{a}}}{100}\right) \times 3.664$$

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.

Available methods, for estimating emissions from aluminium involving the production of baked carbon anodes, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 4.80	NO	NO
Method 2	Section 4.81	NO	NO
Method 3	Section 4.82	NO	NO
Method 4	Method 4 under Part 1.3	NO	NO

NO = Not occurring.

### 4.80 Method 1—aluminium (baked carbon anode production)

Method 1 is:

$$\mathbf{E}_{ij} = \left(\mathbf{GA} - \mathbf{Hw} - \mathbf{BA} - \mathbf{WT}\right) \times 3.664 + \left(\frac{\sum \mathbf{Q}_i}{\mathbf{BA}} \times \mathbf{BA} \times \frac{\left(100 - \mathbf{S}_i - \mathbf{Ash}_i\right)}{100}\right) \times 3.664$$

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.

 $\Sigma Q_i$  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  $S_i$  and  $Ash_i$  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  $S_i$  and  $Ash_i$  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)**

Method 2 and Method 3 are to be drawn from the US Environment Protection Agency, Protocol for Measurement of Tetrafluoromethane ( $CF_4$ ) and Hexafluoroethane ( $C_2F_6$ ) Emissions from Primary Aluminium Production as referenced in the International Aluminium Institute Greenhouse Gas Protocol.

## 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.

Summary of available methods, for estimating tetrafluoromethane emissions aluminium production, by emissions of gas type (j)

	Tetrafluoromethane
Method 2	Section 4.86
Method 3	Section 4.87

## 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<sub>2</sub>-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<sub>2</sub>-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.

Summary of available methods, for estimating hexafluoroethane emissions aluminium production, by emissions of gas type (j)

	Hexafluoroethane
Method 2	Section 4.90
Method 3	Section 4.91

### 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<sub>2</sub>-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<sub>2</sub>-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.

Summary of available methods, for estimating emissions from other metal production, by emissions of gas type (j)

	CO <sub>2</sub>	CH <sub>4</sub>	N <sub>2</sub> O
Method 1	Section 4.94	NO	NO
Method 2	Section 4.95	NO	NO
Method 3	Section 4.96	NO	NO
Method 4	Method 4 under Part 1.3	NO	NO

NO = Not occurring.

#### 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:

 $\Sigma_i$  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 and 2.4.6; 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:

$$\Sigma_p \operatorname{CCF}_p \times \operatorname{A}_p$$

where:

 $\Sigma_p$  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:

$$\sum_{r} CCF_{r} \times Y_{r}$$

where:

 $\Sigma_r$  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:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

 $CCF_r$  has the same meaning as in step 3.

 $\Delta S_{yr}$  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<sub>2</sub>-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:

 $\sum_{i} CCF_{i} \times \Delta S_{qi} + \sum_{p} CCF_{p} \times \Delta S_{ap} + \sum_{r} CCF_{r} \times \Delta S_{yr} + \alpha \gamma RCCS_{co_{2}}$ 

where:

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

 $CCF_i$  has the same meaning as in step 1.

 $\Delta S_{qi}$  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.

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

 $CCF_p$  has the same meaning as in step 2.

 $\Delta S_{ap}$  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.

 $\Sigma_r$  has the same meaning as in step 3.

 $CCF_r$  has the same meaning as in step 3.

 $\Delta S_{yr}$  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.

 $\alpha$  is the factor <sup>3.664</sup> for converting the mass of carbon dioxide to a mass of carbon.

 $\gamma$  is the factor  $1.861 \times 10^{-3}$  for converting a quantity of carbon dioxide from cubic metres at standard conditions of pressure and temperature to CO<sub>2</sub>-e tonnes.

*RCCS<sub>CO2</sub>* 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

Emissions of hydrofluorocarbon (HFC) or sulphur hexafluoride (SF<sub>6</sub>) gases arise as fugitive emissions from the use of equipment, such as refrigeration, that contains these gases. Production of hydrofluorocarbons and sulphur hexafluoride currently does not occur in Australia.

#### 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

Only a subset of Reporters need to report estimates of emissions of hydrofluorocarbon gases. This reflects the assessment that the benefits of reporting

may not exceed the costs of measurement in many instances given the large number of appliances that contain relatively small refrigerant charges, and the small share of total emissions that these emission sources would represent for many companies and facilities.

Emissions of hydrofluorocarbon gases need only be estimated if:

- hydrofluorocarbon gases are used in the equipment types specified in 4.102(4);
- (b) the equipment type contains a refrigerant charge of more than 100 kilograms of refrigerants for each unit;
- (c) the refrigerants have a weighted-average Global Warming Potential of over 1000; and
- (d) the equipment is operated by a facility attributable to an ANZSIC classification listed in 4.100 (1) (b).

All users of SF<sub>6</sub> should report SF<sub>6</sub> emissions.

NGER methods are designed to be consistent with the provisions relating to Australia's international reporting obligations. Under these obligations, the reportable gases are those specified in the IPCC second assessment report. As such, the list of gases does not include HCFC's which are scheduled gases to be phased out under the Montreal Protocol.

The use of refrigerant blends is common in applications covered under NGERS. The table below lists a range of common blends and the constituents of each blend.

Summary of common refrigerant blends and their ingredients

	Gas							
Blend	HFC125	HFC134a	HFC143a	HFC 32	Other (non HFC)			
HFC-404A	44%	52%	4%					
HFC-407A	40%	40%		20%				
HFC-407C	25%	52%			23%			
HFC-410A	50%				50%			

HFC-413A		88%			12%
HFC-417A	47%	50%			3%
HFC-507A	50%		50%		
HFC-407B	40%	40%		20%	

#### 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

These thresholds are intended to limit the application of the Part because of the large number of diverse and minor sources of emissions for this category.

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

Method 1 for emissions of HFCs and  $SF_6$  calculates emissions during the year using default leakage rates for the particular types of equipment within the facility. HFC and  $SF_6$  emissions should be estimated separately according to Method 1.

(1) Method 1 is:

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

where:

 $E_{jk}$  is the emissions of gas type (*j*), either hydrofluorocarbons or sulphur hexafluoride, summed over each equipment type (*k*) during a year measured in CO<sub>2</sub>-e tonnes.

*Stock*<sub>*jk*</sub> is the stock of gas type (j), either hydrofluorocarbons or sulphur hexafluoride, contained in equipment type (k) during a year measured in CO<sub>2</sub>-e tonnes.

 $L_{jk}$  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<sub>jk</sub>*, 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)			
		Hydrofluorocarbon	Sulphur		
		S	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		

Both the type and quantity of hydrofluorocarbon or  $SF_6$  contained in the equipment should be shown on the equipment compliance plate. Quantities of hydrofluorocarbon or  $SF_6$  should be converted into  $CO_2$ -e using the Global Warming Potentials listed in Appendix C. Where a refrigerant blend is used a worksheet for that particular refrigerant blend should be completed and a weighted average of the global warming potentials for each type of refrigerant in the blend should be used to convert to  $CO_2$ -e.

#### Example

For a commercial refrigeration unit with a stock of 2 tonnes of HFC-23 the emissions in CO<sub>2</sub>-e tonnes are:

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

where:
$E_{jk}$ is the emissions of gas type ( $j$ ), either hydrofluorocarbons or sulphur hexafluoride, summed over each equipment type ( $k$ ) during a year measured in CO <sub>2</sub> -e tonnes.
<i>Stock</i> <sub><i>jk</i></sub> is the stock of gas type ( <i>j</i> ), either hydrofluorocarbons or sulphur hexafluoride, contained in equipment type ( <i>k</i> ) during a year measured in CO <sub>2</sub> -e tonnes.
$L_{jk}$ is the default leakage rates for a year of gas type ( <i>j</i> ) mentioned in columns 3 or 4 of an item in the table in subsection (4) for the equipment type ( <i>k</i> ) mentioned in column 2 for that item.
Convert the tonnes of HFC-23 to CO <sub>2</sub> -e tonnes using the global warming potential for HFC-23 listed in Appendix C
$Stock = 2 \times GWP$
$= 2 \times 14,800$
= 29,600 CO <sub>2</sub> -e tonnes
Emissions in CO <sub>2</sub> -e tonnes are:
= 24,000 x 0.23
= 8,880 t CO <sub>2</sub> -e

#### 4.103 Method 2

The stock may also be estimated from mass balance calculations based on the opening stock of gas; transfers into the facility from additions of gas from purchases of new equipment and replenishments; and transfers out of the facility from disposal of equipment or gas. Method 2 uses the mass balance worksheet in Appendix A of the ENA Industry Guideline for SF<sub>6</sub> Management and reporters should use this worksheet for both SF<sub>6</sub> and hydrofluorocarbon gases. A separate worksheet should be completed for each type of gas.

Note that the total annual loss estimate (item F in the mass balance worksheet) for each type of gas should be converted into  $CO_2$ -e using the Global Warming Potentials listed in Appendix C. Where a refrigerant blend is used a worksheet for that particular refrigerant blend should be completed and a weighted average of the global warming potentials for each type of HFC in the blend should be used to convert to  $CO_2$ -e.

As the mass balance worksheet may not include all items for addition and subtraction applicable to the management of refrigerant systems (hydrofluorocarbons), Reporters of HFCs may modify the worksheet in order to obtain a more accurate estimate of emissions.

Storage means all equipment, cylinders and other containers which hold hydrofluorocarbons or  $SF_6$  not in use and which meet the requirements of 4.100 and 4.101.

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<sub>6</sub> Management*, Energy Networks Association, 2008.

#### 4.104 Method 3

Alternatively, emissions may be estimated from data on replenishments of gases in equipment as a proxy for leakage and using an assumption that the stock levels of gases within the equipment are maintained at constant levels in order to maintain constant operating efficiency levels. Method 3 uses this approach and refers reporters of SF<sub>6</sub> to the whole section in the *ENA Industry Guideline for SF*<sub>6</sub> *Management,* section 6.3, which provides a discussion as well as a worksheet (by reference to Appendix B).

For reporters of HFCs, however, Method 3 simply references the worksheet in Appendix B of the *ENA Industry Guideline for*  $SF_6$  *Management*, and although it refers to  $SF_6$  can also be applied to HFCs.

A separate worksheet should be completed for each type of gas. The worksheet in Appendix B may not include all the point sources of losses for both  $SF_6$  and HFCs. Therefore this worksheet may be modified to include more point sources where they have been identified by the Reporter.

Note that the total annual loss of each type of gas should be converted into  $CO_2$ -e using the Global Warming Potentials listed in Appendix C. Where a refrigerant blend is used a worksheet for that particular refrigerant blend should be completed and a weighted average of the global warming potentials for each type of HFC in the blend should be used to convert to  $CO_2$ -e.

Storage means all equipment, cylinders and other containers which hold hydrofluorocarbons or  $SF_6$  not in use and which meet the requirements of 4.100 and 4.101.

- 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<sub>6</sub> 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).

Throughout the Waste chapter, emissions of CO<sub>2</sub> generated from waste management are considered to be from biomass sources and therefore do not need to be estimated. For example, landfill gas comprises both methane and carbon dioxide but only the methane component should be reported.

Carbon dioxide produced from the flaring of methane from landfill gas or other emission sources in this chapter is also considered as having been derived from biomass sources and should not be reported.

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

### 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 solid waste disposal in a landfill; and
  - (b) flaring of landfill gas.
- (2) This Part does not apply to 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<sub>2</sub>-e from solid waste disposal at the landfill.

#### 5.3 Available methods

- (1) Subject to section 1.18 for estimating emissions released from the operation of a facility that is constituted by 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 the 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 the 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 landfill 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 landfill 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<sub>2</sub>-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*.

	CO <sub>2</sub>	CH₄	N <sub>2</sub> O
Solid waste disposal at la	ndfill		
Method 1	NA	Section 5.4	NO
Method 2	NA	Section 5.15	NO
Method 3	NA	Section 5.18	NO
Method 4	NA	NA	NO
Methane flared from the	operation of the landfil	11	
Method 1	NA	Section 5.19	Section 5.19
Method 2	NA	Section 5.20	Section 5.20
Method 3	NA	Section 5.21	Section 5.21
Method 4	NA	NA	NA
Biological treatment of se	olid waste		
Method 1	NA	Section 5.22	Section 5.22

#### Summary of available methods, by emissions of gas type (j)

NA = Not available or Not applicable. NO = Not occurring.

#### Future work

It is intended that methods for the direct monitoring of emissions at landfills be developed over time. No method 4 has been specified in the Determination. Further development work and consultation is required to establish the appropriateness of various monitoring techniques before their inclusion.

# Division 5.2.2—Method 1—emissions of methane released from landfills

Method 1 is consistent with the methods used for Australia's *National Greenhouse Accounts.* It is intended that methane generated from solid waste disposal is estimated principally using data on the receipt of solid waste materials at the landfill (often required under State Government levy or reporting arrangements) and the First Order Decay (FOD) model provided in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*, except in certain circumstances specified below.

The quantity of methane generated from solid waste disposal is estimated using a carbon mass balance approach consistent with the First Order Decay (FOD) model (IPCC 2006). Methane is generated by the decay of the decomposable degradable organic carbon stock in the landfill site and reflects waste disposal activity over many decades. The concept of the carbon stock model approach is illustrated in Figure 1.

Methane generated from the landfill at any point in time depends on the stock of decomposable degradable organic carbon inside the landfill. The opening stock of decomposable degradable organic carbon decays over the year ( $\Delta C_{os}$ ) resulting in the generation of landfill gas with the remainder going to the year's closing stock. Additionally, decomposable degradable organic carbon enters the landfill system through the deposition of new waste during the reporting year dC<sub>a</sub>. A portion of the newly deposited decomposable degradable organic carbon may decay in the reporting year  $\Delta C_a$  and the remainder contributes to the closing stock of decomposable degradable organic carbon  $C_{cs}$ .



#### Figure 1: Carbon stock model flow chart

#### Principal method for estimation of emissions

The total change in decomposable degradable organic carbon stock is estimated simultaneously with estimated methane generation.

Methane generated at the landfill:

$$CH_{4 \text{ gen}} = (\Delta C_a(t) + \Delta C_{os}(t)) \times F \times 1.336 \text{ x } 21$$

Decomposable degradable organic carbon lost through decay during the year t:

$$\Delta C_{os}(t) = C_{os}(t) \times (1 - e^{-k})$$
  
$$\Delta C_{a}(t) = dC_{a}(t) \times [1 - e^{-k \times (13 - M)^{1/2}}]$$

Accumulated decomposable degradable organic carbon at the landfill at the end of the year

$$C_{cs}(t) = C_{os}(t) - \Delta C_{os}(t) + dC_{a}(t) - \Delta C_{a}(t)$$

Where:

 $CH_{4 \text{ gen}}$  is the quantity of methane generated at the landfill (in tonnes of CO<sub>2</sub>-e)

dCa(t) is the quantity of decomposable degradable organic carbon from newly deposited waste arriving at the landfill and is derived using the equation:

 $dC_a(t) = \sum_i (Ca(t) \times DOC_{Fi} \times MCF)$ 

Where:

 $C_a(t)$  is the quantity of degradable organic carbon

in newly deposited waste at the landfill during the

year t (in tonnes)

 $DOC_F$  is the fraction of degradable organic carbon dissimilated by waste mix type *i* (refer to section 5.14A).

MCF is the methane correction factor for aerobic decomposition and is equal to 1.

Sum for all waste types *i*.

 $\Delta C_a(t)$  is the quantity of decomposable degradable organic carbon from newly deposited waste arriving at the landfill lost through decay (decomposition) (in tonnes)

 $\Delta C_{os}(t)$  is the quantity of decomposable degradable organic carbon from the opening stock of carbon at the landfill lost through decay (decomposition) (in tonnes)

*F* is the fraction of CH<sub>4</sub>, by volume, generated in landfill gas (and equal to 0.5)

**1.336** is the conversion factor from a mass of C to a mass of CH<sub>4</sub>

 $C_{os}(t)$  is the quantity of decomposable degradable organic carbon accumulated in the landfill at the beginning of the year t (in tonnes)

 $C_{cs}(t)$  is the quantity of decomposable degradable organic carbon accumulated in the landfill at the end of the year t (in tonnes)

 $C_a(t)$  is the quantity of decomposable degradable organic carbon in newly deposited waste at the landfill during the year t (in tonnes)

The opening stock of degradable organic carbon for a year  $C_{os}(t)$  is equal to the closing stock  $C_{cs}(t-1)$  of the previous year

M = month when decay process commences, equal to the average delay time (months) + 7. Landfill operators may choose an appropriate value for average delay time between 0 and 12. In the absence of information on delay time, a value of 6 months may be used for average delay time (M = 13).

k = methane generation constant

t = year t (reporting year)

The FOD model estimates CH<sub>4</sub> generated in any given year by adding the newly deposited waste (dC<sub>a</sub>) into the disposal site in one year to the waste left over from the previous year (which is taken as the current year's opening stock –  $C_{os}$ ). The CH<sub>4</sub> generation for the year is then calculated from this 'running total' of the decomposable degradable organic carbon remaining in the site.

The basis for this approach lies in the first order reaction. With a first order reaction the amount of product (here degradable organic carbon decomposed

-  $\Delta C_a(t) + \Delta C_{os}(t)$ ) - is always proportional to the amount of reactant (here  $C_{os} + dC_a$ ).

#### Alternative method for estimation of emissions

Section 5.4 also sets out the circumstances in which an alternative approach to the estimation of emissions will apply. The alternative approach will apply to a facility that captures methane generated by the landfill and where the estimates of the quantity of methane captured for combustion (either at the landfill or elsewhere) and from flaring exceed 75 per cent of the estimated emissions generated by the landfill according to the application of the Tier 2 FOD model.

If the 75 per cent threshold is exceeded, (that is, if the quantity of methane captured, transferred offsite or flared exceeds 75 per cent of the estimated methane generated at the landfill) then it is intended that emissions would be estimated as [1/0.75] multiplied by the quantity of methane captured.

Where this threshold has been triggered, it is also important to track the carbon loss  $(\Delta C_{os}(t))$  associated with the estimated emissions. Sections 5.4B and 5.4C of the Determination provide instructions on performing this calculation.

This alternative approach ensures that where a more accurate estimate of emissions generated by the landfill is available – i.e. based on the quantity of emissions captured – that this better data is substituted for the Tier 2 FOD model-generated emissions data.

The choice of 75 per cent as the threshold value reflects advice in the Department of Environment and Heritage publication, National Pollution Inventory – *Emission Estimation Manual for Municipal Solid Waste (MSW) Landfills, Version 1.2,* May 2005 that this constitutes the most common assumption about capture efficiency of landfill sites. A similar approach has recently been adopted by the US Environment Protection Agency.

It is intended that Reporters will be able to use higher-order methods – in particular, method 2 – to establish higher capture efficiencies. A capture efficiency limit of 85 per cent has been established under method-2. Under the method-2 provisions in the Determination, site-specific k values obtained under method-2 would be derived once only. The establishment of the 85% capture efficiency limit is designed to

ensure that methane capture does not exceed methane generation at any time in the future.

## 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:

$$\mathbf{E}_{j} = \left[ \mathbf{CH}_{4}^{*} - \gamma \left( \mathbf{Q}_{cap} + \mathbf{Q}_{flared} + \mathbf{Q}_{tr} \right) \right] \times (1 - \mathbf{OF})$$

where:

 $E_j$  is the emissions of methane released by the landfill during the year measured in CO<sub>2</sub>-e tonnes.

 $CH_4^*$  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<sub>2</sub>-e tonnes.

 $\gamma$  is the factor 6.784  $\times$  10<sup>-4</sup>  $\times$  25 converting cubic metres of methane at standard conditions to CO<sub>2</sub>-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 in accordance with Division 2.3.6.

 $Q_{flared}$  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.

 $Q_{tr}$  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:

$$\frac{\gamma \left( Q_{cap} + Q_{flared} + Q_{tr} \right)}{CH_{4gen}}$$

is less than or equal to 0.75, then:

$$CH_4^* = CH_{4gen}$$

where:

 $CH_{4gen}$  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<sub>2</sub>-e tonnes.

(3) For subsection (1), if:

$$\frac{\gamma \left( Q_{cap} + Q_{flared} + Q_{tr} \right)}{CH_{4gen}}$$

is greater than 0.75, then:

$$\mathrm{CH}_{4}^{*} = \gamma \left( \mathrm{Q}_{\mathrm{cap}} + \mathrm{Q}_{\mathrm{flared}} + \mathrm{Q}_{\mathrm{tr}} \right) \times \left( \frac{1}{0.75} \right)$$

where:

 $\gamma$  is the factor 6.784 x 10<sup>-4</sup> x 25 converting cubic metres of methane at standard conditions to CO<sub>2</sub>-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<sub>4gen</sub> 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<sub>4gen</sub>

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<sub>4gen</sub>

- (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 ( $\Delta C_{OSt}$ ) 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<sub>2</sub>-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:

$$C_{cst} = C_{ost} - \Delta C_{os}$$

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.

 $\Delta C_{ost}$  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.

#### Guidance on using Ccst calculated according to 5.4C in the FOD model.

As the FOD model tracks the decay of individual waste mix types, it is necessary to calculate a closing stock of carbon (Ccst) for each waste mix type. This may be done by allocating  $\Delta$ Cost to each waste mix type on the basis of the proportions of Ccst by waste mix type for the year preceding the first year in which the 75 per cent capture rule is triggered.

If there are no preceding years in which capture was below 75 per cent, Ccst may be allocated to each waste mix type according to the waste composition.

#### 5.4D Equation—quantity of methane generated by landfill for calculating CH<sub>4gen</sub>

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<sub>2</sub>-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.

 $\Delta C_{ost}$  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:

 $C_{osit}$  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:

 $C_{osit} = C_{csit\text{-}1}$ 

where:

 $C_{csit-1}$  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:

 $C_{csit} = C_{osit} - \Delta C_{osit} + C_{ait} - \Delta C_{ait}$ 

and:

 $\Delta C_{at}$  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:

$$\Delta C_{at} = \sum_{i} C_{ait} \times \left[1 - e^{-ki \times (13 - M)/12}\right]$$

where:

 $C_{ait}$  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:

$$C_{ait} = (Q_{it} \times DOC_i \times DOC_{fi} \times MCF)$$

where:

 $Q_{it}$  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.

 $DOC_i$  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.

 $DOC_{fi}$  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:

 $k_i$  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.

 $\Sigma_i$  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  $\Delta C_{ost}$ , see Volume 5, Chapter 3 of the 2006 IPCC Guidelines, equation 3.5; and

- (c) the definition of  $\Delta C_{at}$ , see Volume 5, Chapter 3 of the 2006 IPCC Guidelines, equation 3.A1.13; and
- (d) the definition of  $\Delta C_{ait}$ , 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.

Sections 5.5 - 5.8 set out the criterion available for estimating the tonnage of total solid waste received at the landfill. However, the tonnage of waste disposed of in a landfill is required by the IPCC Tier 2 FOD model. Reporters can determine the amount of waste disposed of in a landfill by subtracting the amount of waste diverted from disposal in a landfill from the amount of waste received at the landfill. Section 5.11A sets out the parameters available to make such deductions. This concept is best clarified by the following:

 Waste disposed of in a landfill = waste received at the landfill – waste diverted from disposal (i.e. the quantity of material that is composted, recycled or used onsite).

According to the NGER Regulations, it is necessary to report the amount of waste entering (disposed at) the landfill and the amount of waste received at the landfill for treatment (either onsite or offsite) or use (waste diverted) when submitting an NGER Report. Consequently, it is necessary to report both of these values into the NGER Solid Waste Calculator. The Clean Energy Regulator can provide further advice about the correct use of the NGERS solid waste calculator.

#### 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

Sections 5.9 – 5.10 set out data requirements for the composition of the waste data split between general and homogenous waste streams. General waste stream data required include tonnes of (a) municipal solid waste (b) commercial and industrial waste and (c) construction and demolition waste. Homogenous waste stream data required include tonnes of (a) shredder flock (b) alternative waste treatment residues and (c) inert waste.

It is intended that Reporters should adopt the classifications adopted for state-based levy systems where applicable and if not, classify waste according to the principle activity leading to the generation of the waste. For example:;

 Waste from domestic premises, council collections and other municipal sources may be classed as municipal solid waste;

- Waste from composting or biological treatment facilities may be classed as alternative waste treatment residues;
- Waste from scrap metal recycling facilities may be classed as shredder flock.

The Australian, New Zealand Standard Industry Classification (ANZSIC) system may also be useful in classifying the waste generating activities. For example:;

- Waste from activities within ANZSIC divisions C, G or H may be classified as commercial and industrial waste;
- Waste from activities within ANZSIC division E may be classified as construction and demolition waste;

•waste from mixed load deliveries of domestic and commercial waste should be classed according to the dominant source.

- (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										
Ite m	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	
	Waste stream	NSW %	VIC %	QLD %	WA %	SA %	TAS %	ACT %	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	Col.	Col.	Col.	Col.	Col.	Col. 7	Col.	Col.
		2	3	4	5	6		8	9
	Waste stream	NSW	VIC	QLD	WA	SA	TAS	ACT	NT
		%	%	%	%	%	%	%	%
1	Commercial and industrial waste	61	38	25	23	30	77	74	25

Waste	Waste streams and estimation of tonnage									
Item	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	
	Waste stream	NSW %	VIC %	QLD %	WA %	SA %	TAS %	ACT %	NT %	
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**

Homogenous waste streams have been introduced to cover situations where a landfill receives discrete deliveries of waste of a homogenous composition during the year. Homogenous waste streams allow a landfill operator to undertake streamspecific sampling and analysis for waste loads of single origin together with default compositions for waste loads of dispersed origin.

For the shredder flock waste stream, it is a requirement that the composition of this stream be determined according to the sampling and analysis requirements set out in section 5.11 (2). For alternative waste treatment residues where it is not possible to determine the stream composition, a default DOC and DOCf values and decay rate constants are provided.

- (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).

Note: Waste accepted in the landfill from the year of opening of the landfill that meets the criteria of a homogenous waste stream must be treated as a homogenous waste stream for the purpose of calculating the opening stock of degradable organic carbon at the beginning of the reporting year for all waste mix types.

It is intended that the requirements of 5.10A(2) restrict the use of homogenous waste streams to the following very specific circumstances:

- Waste has been generated by a single plant or activity. For example, shredder flock delivered to landfill cannot come from multiple recycling plants in a single load. Each plant's waste must be treated individually;
- only those homogenous waste streams identified are being generated at the waste generating activity;
- there must be no pre-sorting of general waste streams in order to derive homogenous waste streams. For example, where a construction activity has generated general construction and demolition waste, it is not possible to extract the inert component of the general stream prior to disposal and class it as homogenous inert waste while maintaining the default composition for the residual construction and demolition stream;

Landfill operators should maintain records to justify the waste streams classifications adopted for the purposes of NGER reporting.

#### 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					

Default waste stream percentage for waste mix type										
Item	Column 1	Column 2	Column 3	Column 4	Column 5					
	Waste mix type	Municipal solid waste class I default (%)	Municipal solid waste class II default (%)	Commercial and industrial waste default (%)	Construction and demolition waste default (%)					
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:

$$\mathbf{W}_{\text{mtuadj}} = \mathbf{W}_{\text{mtu}} + \frac{\left(\mathbf{W}_{\text{mtr}} - \mathbf{W}_{\text{mtrmax}}\right) \times \mathbf{W}_{\text{mtu}}}{\sum \mathbf{W}_{\text{mtu}}}$$

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.

 $\sum$  means sum the results for each unrestricted waste mix type.

Defau	Default waste stream percentage for waste mix type									
Item	Column 1	Column 2	Column 3	Column 4	Column 5					
	Waste mix type	Municipal solid waste class I default (%)	Municipal solid waste class II default (%)	Commercial and industrial waste default (%)	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:

$$W_{\text{mtuadj}} = 15.5 + \frac{(21.5 - 5) \times 15.5}{(15.5 + 4 + 12.5 + 4 + 1.5 + 3.5 + 37.5)}$$
  
= 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 <sub>mtu</sub> (%)	W <sub>mtr</sub> (%)	W <sub>mtrmax</sub> (%)	Wmt <sub>adj</sub> (%)
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

Item	Waste mix type	W <sub>mtu</sub> (%)	W <sub>mtr</sub> (%)	W <sub>mtrmax</sub> (%)	Wmt <sub>adj</sub> (%)
5	Textiles	4.0			4.8
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

Item	Waste mix type	Degradable organic carbon value
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

The calculation of the opening stock of carbon in a landfill in any given year requires historical data on quantities and composition of waste sent to landfill in all prior years of the landfill's operation. These data may not be available in all instances. Section 5.13 sets out the methods that can be applied in determining the opening stock of carbon.

- (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)

Landfill operators have two options for the selection of k values under method 1. The first option is to select k values based upon the state or territory in which the landfill is located. The second option is to select k values based upon the climatic conditions (mean annual temperature, precipitation and evaporation) at or near the landfill site.

Under option 2, mean annual temperature can be calculated from data available on the Bureau of Meteorology website (<u>http://www.bom.gov.au/climate/data/</u>). The BOM provide data on mean maximum and mean minimum temperatures over the entire
time-series of weather station data. Mean annual temperature is calculated as the arithmetic average of the mean maximum and mean minimum temperature.

Mean annual precipitation is available directly from the BOM weather station data. No additional calculations are required in order to derive this value.

Where BOM records are missing data for any of the previous 10 years, landfill operators may use average values to fill in data gaps in order to undertake the required calculations.

Landfills in the "temperate" classifications will also need an estimate of mean annual evaporation. Mean annual evaporation data are available from certain BOM weather stations. Under the provisions of section 5.14, mean annual evaporation data should be obtained from the closest weather station to the landfill for which evaporation records exist. Reporters should consult the BOM on obtaining the appropriate evaporation records required for the selection of climate-based 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 valu	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		
		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	
		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 <u>www.bom.gov.au.</u>

temperate dry, for a landfill, means that the landfill has:

- (a) a mean annual temperature that is  $20^{\circ}$  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  $20^{\circ}$  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  $20^{\circ}$  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  $20^{\circ}$  centigrade; and
- (b) a mean annual precipitation that is 1 000 mm or more.

#### 5.14A Fraction of degradable organic carbon dissimilated (DOC<sub>F</sub>)

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 <sub>F</sub> 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

#### Example: Calculation of emissions from solid waste disposal

A facility constituted by a managed landfill accepting municipal solid waste uses the IPCC FOD model to determine that the emissions (CH<sub>4 gen</sub>) from the facility are 28,493 tonnes of CO<sub>2</sub>-e during the year. Additionally 1,000,000 m<sup>3</sup> of methane has been captured at the facility (Q<sub>cap</sub>) during the year for combustion. On this basis  $\gamma$ (Q<sub>cap</sub> + Q<sub>flared</sub> + Q<sub>tr</sub>)/CH<sub>4 gen</sub> is assessed to be 50% therefore according to section 5.4 – subsection 2 of the Determination, CH<sub>4</sub>\* is taken to equal CH<sub>4 gen</sub>. The reporter elects to use Method 1 (5.2.2 in the *National Greenhouse and Energy Reporting (Measurement) Determination 2008)* for methane released from landfills. Emissions are estimated as follows:

$$E_j = (CH_4 * - \gamma(Q_{cap} + Q_{flared} + Q_{tr})) x (1-OF)$$

where:

 $E_j$  is emissions of methane (CO<sub>2</sub>-e) released by the landfill during the year.

CH<sub>4</sub> \* is the estimated quantity of methane in landfill gas generated by the landfill during the year.

 $\gamma$  is the factor 6.784 x 10<sup>-4</sup> x 25 converting cubic metres to CO<sub>2</sub>-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.

 $Q_{flared}$  is the quantity of methane in landfill gas flared from the landfill during the year and measured in cubic metres.

 $Q_{tr}$  is the quantity of methane in landfill gas transferred out of the landfill during the year and measured in cubic metres.

OF is the oxidation factor (0.1) for near-surface methane in the landfill.

Therefore, to calculate emissions of methane in CO<sub>2</sub> e tonnes :

Total methane generated during the year as estimated using the FOD model = 28,493 tonnes CO<sub>2</sub>-e

 $E_{j} = (CH_{4}^{*} - \gamma(Q_{cap} + Q_{flared} + Q_{tr})) \times (1-OF)$ 

=  $(28,493 - 6.784 \times 10^{-4} \times 25 \times (1,000,000 + 0 + 0)) \times (1-0.1)$ 

Total emissions of methane =  $13,229 \text{ t CO}_2$ -e

#### 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)

Section 5.15 sets out Method 2, which is based on the method published in the *IPCC* 2000 Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories.

- (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<sub>2</sub>-e tonnes, using the following equation:

 $E_j = \sum_z E_{jz}$ ; 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<sub>2</sub>-e tonnes, using the following equation:

$$E_{jz} = [CH_{4genz} - \gamma(Q_{capz} + Q_{flaredz} + Q_{trz})] \times (1 - OF)$$

where:

 $E_j$  is the emissions of methane released by the landfill during the reporting year, measured in CO<sub>2</sub>-e tonnes.

 $E_{jz}$  is the emissions of methane released by the landfill from a sub-facility zone during the reporting year, measured in CO<sub>2</sub>-e tonnes.

 $CH_{4genz}$  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<sub>2</sub>-e tonnes.

 $\gamma$  is the factor 6.784  $\times$  10<sup>-4</sup>  $\times$  25 converting cubic metres of methane at standard conditions measured to CO<sub>2</sub>-e tonnes.

 $Q_{capz}$  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.

 $Q_{flaredz}$  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.

 $Q_{trz}$  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.

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), *CH*<sub>4genz</sub> 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:

$$\frac{\gamma \left( \mathbf{Q}_{cap} + \mathbf{Q}_{flared} + \mathbf{Q}_{tr} \right)}{\mathbf{CH}_{4gen}}$$

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:

 $Q_{cap}$  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.

 $Q_{flared}$  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.

 $Q_{tr}$  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.

 $CH_4^*$  is the estimated quantity of methane in landfill gas generated by the landfill during the year, measured in CO<sub>2</sub>-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 CO<sub>2</sub>-e tonnes.

(4) For subsection (1), if:

$$\frac{\gamma \Big( Q_{cap} \ + \ Q_{flared} \ + \ Q_{tr} \Big)}{CH_{4gen}}$$

is more than the collection efficiency amount for the landfill calculated in accordance with section 5.15C, then:

$$CH_{4z}^{*} = \gamma (Q_{capz} + Q_{flaredz} + Q_{trz}) \times \left(\frac{1}{CEA}\right)$$

where:

 $\gamma$  is the factor 6.784  $\times$  10<sup>-4</sup>  $\times$  25 converting cubic metres of methane at standard conditions measured to CO<sub>2</sub>-e tonnes.

*CEA* is the collection efficiency amount for the landfill calculated in accordance with section 5.15C.

 $CH_{4z}^*$  is the estimated quantity of methane in landfill gas generated by the sub-facility zone during the year, measured in CO<sub>2</sub>-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 ( $\Delta C_{ost}$ ) must be calculated using the equation mentioned in section 5.15A; and
  - (b) the quantity of the closing stock of decomposable degradable organic carbon ( $\Delta C_{cst}$ ) 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<sub>4gen</sub>

- 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 ( $\Delta C_{OSt}$ ) 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.

 $\Delta C_{ost}$  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

The revised method for determining landfill gas collection efficiency under method 2 is based on the US EPA Mandatory Reporting of Greenhouse Gases final rule (FR Vol 74/ No. 209) which provides for the application of collection efficiency limits exceeding 85% under specific operational circumstances.

The Mandatory Reporting Rule sets out a calculation that must be undertaken to determine a whole of landfill collection efficiency. The calculation involves the delineation of landfill area by cover type and takes into account system coverage, operation, and cover system materials.

(1) Subject to subsection (2), the collection efficiency limit for a landfill is calculated using the following formula:

$$\frac{(A3 \times 60\% + A4 \times 75\% + A5 \times 95\%)}{(A2 + A3 + A4 + A5)}$$

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: Area of landfill in square metres with active gas collection × 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 <u>www.environment.gov.au</u>.

#### Technical Guidelines relating to landfill site plans

The operator of the landfill must prepare a site plan prior to the commencement of the use of method 2 that must include the following information:

- a. a description of basic site characteristics:
  - the planned life of the facility and permitted volumes of waste disposal; the exact boundaries of the waste disposal area;

- containment design (liner and capping);
- fill process (for example, phased or cell; landfill or landraise);
- sideslopes and edges;
- any fissures or weak points in the cap where emissions may be high; and
- b. spatial mapping of permanent and temporary capped zones and uncapped zones; and
- c. spatial mapping of volumes, mass and age of waste disposed at the facility; and
- d. description of gas control systems:
  - locations of wells and their capacity and other relevant attributes;
  - gas monitoring points;
  - density of well sub-systems;
  - description of flares (location, timing and gas capacities); and
- e. leachate management systems;
  - leachate towers, sumps, risers systems (including recirculation)
  - leachate monitoring points
  - presence of former co-disposal systems (e.g. liquid disposal trenches);
- f) the boundaries of all sub-facility and representative zones; and
- g) any other features of the facility that could impact on flux box locations or the capacity of a representative zone or to be representative of facility.

### 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.

It is common for landfills to practice progressive filling of excavated areas. In this context, the requirements above will dictate how many completed cells are to be included in the representative zone. In the following example, there are 3 completed cells which are capped with active gas collection and a fourth cell which is being filled. The completed cells are sealed on 2 sides by the excavation edge and the third side by a temporary cap (which will subsequently be removed for the filling of future cells). The representative zone in this situation is indicated by the red box in the following diagram. The requirement of being confined on 3 sides by low permeability barriers and the fourth side by an active gas collection system restricts the selection of the representative zone to cells 1 and 2 (subject to the other requirements for representative zones).

Representative Zone



## Edge of Quarry (Impervious)

### 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.

#### Expert reports on representative zones

The operator of the facility must enter into a written agreement with the expert, which may be by an exchange of letters, specifying the terms governing the preparation of a report providing an assessment on the selection of the representative zone.

The written report must contain all information which the operator and others likely to rely on the report would reasonably require, and reasonably expect to find in the report, for the purpose of making an informed decision about the representativeness of the selected zone.

The report should include:

- (a) a description of the relevant aspects of the facility;
- (b) an account of the material history of the facility, including the volume, mass, age and types of waste in the representative zone;
- (c) an assessment as to the degree of uniformity of moisture levels between the representative zone and the remainder of the landfill, taking into account the technologies and processes used in the representative zone that affect moisture levels compared with other parts of the facility including the use of leachate recirculation and cell size; and
- (d) an assessment of the degree of uniformity of the depth of waste, taking into account the results of volumetric surveys conducted for the site, if any have been conducted.

The independent expert must also provide an assessment as to whether the boundaries of the representative zone are appropriate. The boundaries of the zone should define the volume of waste that is generating the gas captured by the collection system within the representative zone.

For any given point on the boundary, the location of the boundary should be located by determining a distance between two adjacent wells - one well internal to the selected area and one well external to the selected area - which is proportional to the relative landfill gas flow rate of each well recorded over the test period. The data used must have been recorded during periods of operation of the collection system that reflect normal operating conditions (i.e. consistent with the operation of the system on days of flux box measurement). There must be no significant net flow of landfill gas across the representative zone boundary when the measurements are made.

For zones with vertical well systems in place, the boundary can be assumed to be a vertical surface extending from the landfill surface to the base of the waste.

For zones with horizontal well systems in place the representative zone may be estimated on the zone of influence of the horizontal well system.

Detailed technical information and data should be included in the report if their understanding is important to the assessment. Explanations of unusual or new technical processes and activities that may be material to the understanding of the assessment should be included, where commercial confidentiality considerations allow.

Experts must not rely uncritically on the data and other information provided, either by the operator of the facility or obtained otherwise. They must undertake suitable checks, enquiries, analyses and verification procedures to establish reasonable grounds for establishing the soundness of the contents and conclusions of the report.

The expert must either certify that the representative zone has been selected in accordance with these *Guidelines* and the *National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2012,* or the contrary, and personally sign the report.

# 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<sub>4</sub> 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<sub>4</sub> 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<sub>4</sub> 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<sub>4</sub> 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.

#### Expert reports on emission measurements

The operator of the facility must enter into a written agreement with the expert, which may be by an exchange of letters, specifying the terms governing the preparation of a report on the estimation of emissions from the representative zone.

The written report must contain all information which the operator and others likely to rely on the report would reasonably require, and reasonably expect to find in the report, for the purpose of making an informed decision about the estimated emissions from the representative zone. The report must include:

- (a) sufficient information about the method(s) used to conduct the walkover and flux box surveys so that another expert could understand the procedures used and analyses undertaken. This information must include:
  - a description of the precise boundaries of the representative zone, and of any recalculations to the estimated boundaries made by the expert for the conduct of the flux box test;
  - a description of the facility and any features which may have affected placement of flux boxes;
  - dates and times at which measurements were undertaken;

- details about the precise location of flux boxes operated for the measurement process and any relevant information that may have affected the placement of the flux boxes;
- (b) sufficient information about the results obtained so that another expert could understand the procedures used and replicate the estimates. This information must include:
  - data on all measurements undertaken, and methods used to determine a gas flow rate estimate at individual flux boxes; and
  - details of the geospatial techniques used and the calculations made to estimate the flow of methane emissions from the representative zone from the measurements taken at individual flux boxes.
- (c) a qualitative assessment of the accuracy of the measurements obtained. This assessment must take account of relevant conditions that may have affected the measurements taken. The report must include data on:
  - rainfall;
  - barometric pressure;
  - wind speed; and
  - temperature;

at the facility or as otherwise specified for the duration of the measurement period. All relevant data for the immediate period prior to the measurements being undertaken, as considered appropriate by the expert, must also be recorded.

- (d) a review of any other matters that are material to the report;
- (e) information regarding all sources of data used;
- (f) a concise summary setting out the key data and important assumptions made and the conclusions drawn by the expert.

Detailed technical information and data should be included in the report if their understanding is important to the assessment. Explanations of unusual or new technical processes and activities that may be material to the understanding of the assessment should be included, where commercial confidentiality considerations allow.

Experts must not rely uncritically on the data and other information provided, either by the operator of the facility or obtained otherwise. They must undertake suitable checks, enquiries, analyses and verification procedures to establish reasonable grounds for establishing the soundness of the contents and conclusions of the report.

The expert must certify that the estimate of emissions from the representative zone has been prepared in accordance with these Guidelines and with the *National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2009* and personally sign the report.

(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.

- $\frac{dc}{dc}$  is the rate of change of gas concentration in the flux boxes over
- $\overline{dt}$  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:

$$HRF = 2 \times \frac{RF}{MRD}$$

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.

The 12 month flux-box measurement period should be the same 12 month period in which the measurements of landfill gas collection in the well system are undertaken.

## 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<sub>2</sub>-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  $\pm 0.001$  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*<sup>%</sup> is the incremental percentage ( $\leq 1\%$ ).

- (3) For subsection (1):
  - (a) CH<sub>4gen</sub> 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  $\pm 0.001$  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<sub>i</sub> 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<sub>i</sub> 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.

#### Notes on resolution of equation in 5.17L

Method 2 rests on the measurement of a flow of methane estimated at a point in time. This flow of methane must reflect the decomposition of an amount of carbon in the wastes deposited in the representative zone.

However, the data on  $C_a$  is subject to some uncertainty – more uncertainty than for the measurement of methane generated and, if underestimated, may preclude a solution to the estimation of 'k'. Consequently, a minimum requirement must be established in relation to  $C_a$  to underpin the estimate of 'k'. That is, the observed amount of methane generated by the landfill must put a floor under the amount of carbon decomposing in the representative zone of the landfill such that:

(1) C<sub>a</sub> ≥ C<sub>a</sub>~

where  $C_{a}$ ~ is the minimum amount of degradable carbon required to solve for 'k'.

In addition, the non-linear nature of the equation means that it is possible, mathematically, to derive a non-unique solution for the value of 'k'. Consequently, it is necessary to add an additional constraint to clarify the appropriate approach to the estimation of 'k'. It is assessed that 'k' must occur in the range where, for a given measurement of methane generated in the representative zone, a higher value of C<sub>a</sub> results in a lower 'k'. That is, given that the amount of methane generated is well known, and if it is being derived from what is considered to be a large mass of carbon, then a slower rate of methane flow observed must reflect, all other things being equal, a slower rate of methane generation.

This condition is expressed as:

(2)  $\delta k/\delta C_a \leq 0$ 

where  $\delta k$  is the change in k, and

 $\delta C_a$  is the change in  $C_a$  in the representative zone

The condition (1) ensures that the solution for 'k' occurs in the range where, for a given measurement of methane generated in the representative zone, higher estimated values of  $C_a$  result in lower values of 'k'.

Decay rate constant (k) plotted against the quantity of degradable organic carbon (C<sub>a</sub>) for a given flow rate and average age of refuse  $\frac{70000}{70000}$ 



### 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)

Section 5.18 sets out Method 3, which is the same as for Method 2, except that the sampling requirements of the US Environment Protection Agency *Method 2E*, *Determination of landfill gas flow production rates* are applied.

- (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

Sections 5.19-5.21 set out Methods 1, 2 and 3 for the flaring of methane in landfill gas. Method 1 is derived from the methods used for the *National Greenhouse Accounts*. Methods 2 and 3 rely on the sampling and analysis of the fuel to estimate the gas composition of the fuel more closely in order to estimate the quantity of methane flared more accurately.

(1) For subparagraph 5.3(b)(i), method 1 is:

$$\mathbf{E}_{j \text{ flared}} = \mathbf{Q}_{\text{flared}} \times \mathbf{E} \mathbf{C}_{i} \times \frac{\mathbf{E} \mathbf{F}_{ij}}{1\,000}$$

where:

 $E_{j \text{ flared}}$  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<sub>2</sub>-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<sub>2</sub>-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<sub>flared</sub>* 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 at a landfill

Section 5.22 sets out Method 1 for emissions released from the Biological treatment of solid waste production. The method to be used is described in *IPCC 2006 Guidelines for National Greenhouse Gas Inventories Volume 5, Chapter 4.* 

(1) For subparagraph 5.3(1)(c)(i) and paragraph 5.3(1)(d), method 1 is:

 $E_{ij} = (M_i \times EF_i) - R$ 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<sub>2</sub>-e per tonne of waste processed.

 $E_{ij}$  is the emissions of the gas type (*j*), being methane or nitrous oxide, released from the landfill during the year from the biological treatment type (*i*) measured in CO<sub>2</sub>-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 landfill from the biological treatment of solid waste measured in tonnes of CO<sub>2</sub>-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	En	<b>Emission factor</b>			
		tonnes CO <sub>2</sub> -e	tonnes CO <sub>2</sub> -e/tonne of waste treated			
		Methane	Nitrous Oxide			
1	Composting at the landfill	0.019	0.029			
2	Anaerobic digestion at the landfill	0.025	0			

### 5.22AA Method 4—biological treatment of solid waste at the landfill

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**

Division 5.2.7 sets out the methods landfill operators must use to derive legacy and non-legacy emissions for the purposes of reporting covered emissions under the Safeguard Mechanism. It is intended that Division 5.2.7 applies to landfill operators using any of the available solid waste methods specified in section 5.3.

## 5.22A Legacy emissions estimated using method 1—sub-facility zone options

- 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<sub>2</sub>-e using the following formula:

$$E_{lw} = \left[ CH_{4genlw} - \gamma \left( Q_{caplw +} Q_{fllw +} Q_{trlw} \right) \right] \times (1 - OF)$$

where:

 $E_{lw}$  is the quantity of methane released by the landfill from legacy waste, measured in CO<sub>2</sub>-e tonnes.

*CH*<sub>4genlw</sub> is the quantity of methane generated from legacy waste, measured in CO<sub>2</sub>-e tonnes.

 $\gamma$  is the factor 6.784  $\times$  10-4  $\times$  25 converting cubic metres of methane at standard conditions measured to CO<sub>2</sub>-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.

 $Q_{flw}$  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:

 $Lr_{z} = CH_{4genlwz} / (CH_{4genz})$ 

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*<sub>4genlwz</sub> is the quantity of methane generated from legacy waste in a sub-facility zone, measured in CO<sub>2</sub>-e tonnes.

 $CH4_{genz}$  is the methane generated from total waste deposited in a sub-facility zone, measured in CO<sub>2</sub>-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:

$$Q_{\text{caplw z}} = Q_{\text{cap z}} \times Lr_{z}$$

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:

 $Q_{\text{fllw z}} = Q_{\text{fl z}} \times Lr_{z}$ where:

 $Q_{flw z}$  is the estimated quantity of methane in landfill gas flared from landfill legacy waste during the reporting year for each sub-facility zone.

 $Q_{flz}$  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.

 $Q_{trz}$  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<sub>4genlw z</sub>)

Calculate CH<sub>4genlw z</sub>:

- (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:

$$CH_{4genlw} = \sum_{z} CH_{4genlw z}$$

where:

*CH4<sub>genlw</sub>* is the methane generated from legacy waste deposited at the landfill, measured in CO<sub>2</sub>-e tonnes.

 $\sum_{z}$  is the sum of all sub-facility zones.

 $CH_{4genlw z}$  is the quantity of methane generated from legacy waste in a sub-facility zone, measured in CO<sub>2</sub>-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:

$$Q_{caplw} = \sum_{z} Q_{caplw z}$$

where:

 $Q_{caplw}$  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:  $Q_{trlw} = \sum_{z} Q_{trlwz}$ 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.

 $Q_{trlwz}$  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:

$$Q_{\text{fllw}} = \sum_{z} Q_{\text{fllw}z}$$

where:

 $Q_{flw}$  is the quantity of methane flared from landfill legacy waste during the reporting year.

 $\sum_{z}$  is the sum of all sub-facility zones.

 $Q_{fllwz}$  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<sub>2</sub>-e tonnes.

 $CH_{4genj}$  is the methane generated in landfill gas from total waste deposited at the landfill, measured in CO<sub>2</sub>-e tonnes.

*CH4<sub>genlw</sub>* is the methane generated in landfill gas from legacy waste deposited at the landfill, measured in CO<sub>2</sub>-e tonnes.

(2) Emissions from non-legacy waste must be calculated using the following formula, measured in CO<sub>2</sub>-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<sub>2</sub>-e tonnes:

 $E_{lw}$  is the quantity of methane from legacy waste deposited at the landfill, measured in CO<sub>2</sub>-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.
- (2) In this section, *domestic or commercial wastewater* means liquid wastes and sludge (including human waste) from housing or commercial premises.

Note: Part 5.3 is intended for use by centralised municipal wastewater treatment

plants. Onsite industrial wastewater treatment is covered under part 5.4.

### 5.24 Available methods

- 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

	CO <sub>2</sub>	CH4	N <sub>2</sub> O			
Domestic and Commercial waste water management						
Method 1	NA	Section 5.25	Section 5.31			
Method 2	NA	Section 5.26	Section 5.32			
Method 3	NA	Section 5.30	Section 5.36			
Method 4	NA	NA	NA			
Methane flared from the operation of the facility						
Method 1	NA	Section 5.37	Section 5.37			
Method 2	NA	Section 5.38	Section 5.38			
Method 3	NA	Section 5.39	Section 5.39			
Method 4	NA	NA	NA			

#### Summary of available methods by emissions of gas type (j)

NA = Not available. NO = Not occurring.

- (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)

Section 5.25 sets out Method 1 for wastewater handling – domestic and commercial.

Method 1 for wastewater handling is based on the *National Greenhouse Accounts* methods, except in certain circumstances, specified below.

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

Method 1 provides a method for estimating emissions in the absence of data on Chemical Oxygen Demand (COD) or Biochemical Oxygen Demand (BOD) estimates of on-site wastewater and sludge.

Section 5.25 sets out that under certain specific circumstances an alternative estimation approach should apply. These circumstances are for facilities that capture methane generated by the wastewater handling and where the estimates of the quantity of methane captured for combustion (either at the facility or elsewhere) or flaring exceed 75 per cent of the estimated emissions generated from the wastewater from the facility according to the application of the emissions generation model.

The method to be applied in these circumstances is as for the solid waste disposal method set out in section 5.4 with the exception of subsection (5) which provides a calculation specific to wastewater handling based on chemical oxygen demand (COD) in the wastewater and uses methane correction factors (MCF<sub>ww</sub> and MCF<sub>sl</sub>) for the wastewater and sludge. The methane correction factors are the fractions of COD anaerobically treated by the plant. Methane will only be generated through anaerobic treatment of the COD and emissions estimates must be corrected to eliminate any COD that is not anaerobically treated.

As for solid waste disposal, it is intended that Reporters will be able to use direct emissions monitoring systems to establish higher capture efficiencies and to establish emissions directly. This will require the development of direct monitoring methods. None have been specified in this Determination. Further development work and consultation is required to establish the appropriateness of various monitoring techniques before their inclusion.

The intent of the following equation is to reconcile the estimated theoretical amount of methane generated at the wastewater treatment plant (CH4\*) with the actual amount of methane measured in the captured sludge biogas. The difference between the theoretical and measured amounts is assumed to be emitted to the atmosphere and forms the methane emissions estimate from wastewater handling for the facility.

(1) For subparagraph 5.24(1)(a)(i), method 1 is:

$$\mathbf{E}_{j} = \left[ \mathbf{CH}_{4}^{*} - \gamma (\mathbf{Q}_{cap} + \mathbf{Q}_{flared} + \mathbf{Q}_{tr}) \right]$$

where:

 $E_j$  is the emissions of methane released by the plant during the year measured in CO<sub>2</sub>-e tonnes.

 $CH_4^*$  is the estimated quantity of methane in sludge biogas released by the plant during the year measured in CO<sub>2</sub>-e tonnes as determined under subsections (2) and (3).

 $\gamma$  is the factor 6.784 x 10<sup>-4</sup> x 25 converting cubic metres of methane at standard conditions to CO<sub>2</sub>-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:

$$\frac{\gamma \left( Q_{cap} + Q_{flared} + Q_{tr} \right)}{CH_{4gen}}$$

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<sub>2</sub>-e tonnes.

(3) For subsection (1), if:

$$\frac{\gamma \; (Q_{cap} + Q_{flared} + Q_{tr})}{CH_{4gen}}$$

is greater than 0.75, then:

$$\operatorname{CH}_{4}^{*} = \gamma \left( \operatorname{Q}_{\operatorname{cap}} + \operatorname{Q}_{\operatorname{flared}} + \operatorname{Q}_{\operatorname{tr}} \right) \times \left( \frac{1}{0.75} \right)$$

where:

 $\gamma$  is the factor 6.784 x  $10^{-4}$  x 25 converting cubic metres of methane at standard conditions to CO<sub>2</sub>-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*<sub>W</sub> 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*<sub>4gen</sub> is the methane generated from commercial wastewater and sludge treatment by the plant during the year measured in CO<sub>2</sub>-e tonnes.

 $COD_w$  is the chemical oxygen demand (COD) in wastewater entering the plant during the year measured in tonnes.

*COD<sub>sl</sub>* 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:

 $COD_{psl}$  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).

 $COD_{wasl}$  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).

*COD<sub>eff</sub>* is the quantity of COD in 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 default methane emission factor for wastewater with a value of 6.3 CO<sub>2</sub>-e tonnes per tonne COD.

*COD*<sub>trl</sub> is the quantity of COD in sludge transferred out of the plant and removed to landfill measured in tonnes of COD.

*COD*<sub>tro</sub> 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.

 $MCF_{st}$  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 default methane emission factor for sludge with a value of 6.3 CO<sub>2</sub>-e tonnes per tonne COD (sludge).

- (6) For subsection (5), an operator of the plant must choose a treatment for  $MCF_{ww}$  and estimate the quantity of COD removed from the wastewater as sludge ( $COD_{sl}$ ).
- (7) For subsection (5),  $COD_{psl}$  may be estimated using the following formula:

 $VS_{psl} \times 1.99$ 

where:

*VS*<sub>*psl*</sub> is the estimated volatile solids in the primary sludge.

(8) For subsection (5), COD<sub>wasl</sub> may be estimated using the following formula:

 $VS_{wasl} \times 1.48$ 

where:

*VS<sub>wasl</sub>* 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.

The intent of the equation in 5.25 (5) is to estimate the theoretical quantity of methane generated at the plant, based on a simple COD mass balance. The equation is divided into two parts.

The first part is a simple COD mass balance over the main wastewater treatment processes (i.e. "liquid train" primary and secondary treatment). The second part is a simple COD mass balance over the sludge treatment processes (e.g. anaerobic digesters, lagoons, dewatering, etc.).

Each COD mass balance determines how much COD is consumed in the treatment process by converting it to a gas. Multiplying by the maximum methane generation

factor (EF) calculates how much  $CH_4$  would be generated if *all* the COD consumed is converted to  $CH_4$ . Then, multiplying by the process-specific Methane Correction Factor ( $F_{wan}$  or  $F_{slan}$ ) calculates the expected fraction of methane emissions for that particular type of process.



## Division 5.3.3—Method 2—methane released from wastewater handling (domestic and commercial)

Division 5.3.3 sets out Method 2 for the estimation of methane emissions from wastewater handling, which requires estimates of Chemical Oxygen Demand concentrations in wastewater estimated using general sampling provisions for the Guidelines and analysis conducted in accordance with listed Australian or international standards or an equivalent standard. It is likely that many facilities collect this data routinely for existing regulatory reasons.

## 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<sub>2</sub>-e tonnes, using the equation:

$$CH_{4genz}$$
 -  $\gamma \left( Q_{capz} + Q_{flaredz} + Q_{trz} \right)$ 

where:

 $\gamma$  is the factor 6.784 x 10<sup>-4</sup> x 25 for converting cubic metres of methane at standard conditions to CO<sub>2</sub>-e tonnes.

 $CH_{4genz}$  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<sub>2</sub>-e tonnes.

 $Q_{capz}$  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.

 $Q_{flaredz}$  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.

 $Q_{trz}$  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  $CH_{4genz}$  in subsection (1) is worked out for a sub-facility as follows:

Step 1. Calculate the following for the sub-facility:

$$\begin{split} \gamma & \left( \begin{array}{ccc} Q_{capz} \ + \ Q_{flaredz} \ + \ Q_{trz} \end{array} \right) \\ \hline & \left[ \left( \begin{array}{ccc} COD_{wz} \ - \ COD_{slz} \ - \ COD_{effz} \end{array} \right) \times \ MCF_{wwz} \ \times \ EF_{wijz} \ + \\ \hline & \left( \begin{array}{ccc} COD_{slz} \ - \ COD_{trlz} \ - \ COD_{troz} \end{array} \right) \times \ MCF_{slz} \ \times \ EF_{slijz} \end{split} \right. \end{split} \end{split}$$

where:

 $\gamma$  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*<sub>trlz</sub> is the quantity of COD in sludge transferred out of the sub-facility and removed to landfill, measured in tonnes of COD.

	<i>COD<sub>troz</sub></i> 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		
	<ul> <li>(b) if data is available on the biochemical oxygen demand (<i>BOD</i>) in the wastewater—that data converted to COD in accordance with the following formula:</li> </ul>		
	$COD = 2.6 \times BOD_5$		
	$EF_{slijz}$ is the default methane emission factor for sludge with a value of 6.3 CO <sub>2</sub> -e tonnes per tonne of COD (sludge).		
	$EF_{wijz}$ is the default methane emission factor for wastewater with a value of 6.3 CO <sub>2</sub> -e tonnes per tonne of COD.		
	$MCF_{slz}$ is the methane correction factor for sludge treated at the sub-facility during the reporting year.		
	$MCF_{wwz}$ is the methane correction factor for wastewater treated at the sub-facility during the reporting year.		
	$Q_{capz}$ 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).		
Step 2.	If the quantity worked out under step 1 is less than or equal to 1.00, work out $CH_{4genz}$ using the following formula:		
	$ \begin{pmatrix} \text{COD}_{wz} & - & \text{COD}_{slz} & - & \text{COD}_{effz} \end{pmatrix} \times \text{MCF}_{wwz} \times \text{EF}_{wijz} & + \\ \begin{pmatrix} \text{COD}_{slz} & - & \text{COD}_{trlz} & - & \text{COD}_{troz} \end{pmatrix} \times \text{MCF}_{slz} \times \text{EF}_{slijz} $		
	where:		
	$COD_{effz}$ has the same meaning as in step 1.		

*COD*<sub>slz</sub> has the same meaning as in step 1. *COD*<sub>trlz</sub> has the same meaning as in step 1. *COD*<sub>troz</sub> has the same meaning as in step 1.  $COD_{wz}$  has the same meaning as in step 1.  $EF_{slijz}$  has the same meaning as in step 1.  $EF_{wijz}$  has the same meaning as in step 1.  $MCF_{wwz}$  has the same meaning as in step 1. *MCF*<sub>slz</sub> 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*<sub>4genz</sub> using the formula:  $\gamma \left( Q_{capz} + Q_{flaredz} + Q_{trz} \right) \times \left( \frac{1}{1.00} \right)$ where:  $\gamma$  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<sub>slz</sub>* 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<sub>pslz</sub>* 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<sub>waslz</sub>* 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*<sub>4genz</sub> 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

- 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)

Division 5.3.4 sets out Method 3 for the estimation of methane emissions from wastewater handling, which requires estimates of Chemical Oxygen Demand concentrations in wastewater estimated using sampling and analysis conducted in accordance with listed Australian or international standards or an equivalent standard.

## 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)

Section 5.31 sets out Method 1 for the estimation of nitrous oxide emissions.

(1) For paragraph 5.24(1)(b), method 1 is:

$$\mathbf{E}_{j} = (\mathbf{N}_{in} - \mathbf{N}_{trl} - \mathbf{N}_{tro} - \mathbf{N}_{outdisij}) \times \mathbf{E} \mathbf{F}_{secij} + \mathbf{N}_{outdisij} \times \mathbf{E} \mathbf{F}_{disij}$$

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<sub>2</sub>-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*<sub>Pr</sub> 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*<sub>secij</sub> 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	
3	Open coastal waters (ocean and deep ocean)	<ul> <li>(a) for New South Wales—has the meaning given by the definition of <i>open coastal waters</i> in Schedule 3 to the <i>Protection of the Environment Operations (General) Regulation 2009</i> (NSW), as in force on 8 June 2012; and</li> </ul>	
		(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 <u>www.legislation.nsw.gov.au</u>.

- (6) For  $EF_{secij}$  in subsection (1), the emission factor is 4.9 tonnes of nitrous oxide, measured in CO<sub>2</sub>-e per tonne of nitrogen produced.
- (7) For  $EF_{disij}$  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	$EF_{disij}$
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)

Section 5.32 to 5.35 sets out Method 2 for the estimation of nitrous oxide emissions from wastewater handling. Method 2 requires the sampling and analysis of nitrogen quantities in the wastewater and sludge in accordance with listed Australian or international standards or an equivalent standard. It is likely that many facilities collect this data routinely for regulatory reasons.

## 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<sub>org</sub> B, 4500-N<sub>org</sub> C or 4500-N<sub>org</sub> 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)

Section 5.36 sets out Method 3 for the estimation of nitrous oxide emissions from wastewater handling. Method 3 is very similar to Method 2, except that sampling of the water and sludge must be undertaken in accordance with listed Australian or international standards or an equivalent standard.

- (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

Sections 5.37-5.39 set out Methods 1, 2 and 3 for the flaring of gas. Method 1 is derived from the methods used for the *National Greenhouse Accounts*. Methods 2 and 3 rely on the sampling and analysis of the fuel to estimate the gas composition of the fuel in order to estimate the quantity of methane flared more accurately.

## 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:

$$\mathbf{E}_{j \text{ flared}} = \mathbf{Q}_{\text{flared}} \times \mathbf{E} \mathbf{C}_{i} \times \frac{\mathbf{E} \mathbf{F}_{ij}}{1\,000}$$

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<sub>2</sub>-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<sub>2</sub>-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

- 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).

Summary of available methods, by emissions of gas type (j)

	CO <sub>2</sub>	CH4	N <sub>2</sub> O			
Domestic and Commercial waste water management						
Method 1	NA	Section 5.42	NO			
Method 2	NA	Section 5.43	NO			
Method 3	NA	Section 5.47	NO			
Method 4	NA	NA	NO			
Methane flared from the operation of the facility						
Method 1	NA	Section 5.48	Section 5.48			
Method 2	NA	Section 5.49	Section 5.49			
Method 3	NA	Section 5.50	Section 5.50			
Method 4	NA	NA	NA			

NA = Not available. NO = Not occurring.

# Division 5.4.2—Method 1—methane released from wastewater handling (industrial)

## 5.42 Method 1—methane released from wastewater handling (industrial)

Section 5.42 sets out Method 1 for methane emissions from wastewater handling – industrial. It is intended that this method applies to industries producing the following commodities under the applicable ANZSIC codes:

- Dairy products (ANZSIC code 113)
- Pulp, paper and paperboard (ANZSIC code 1510)
- Meat and poultry (ANZSIC codes 1111 and 1112)
- Organic chemicals (ANZSIC codes 18 and 19)
- Raw sugar (ANZSIC code 1181)
- Beer (ANZSIC code 1212)
- Wine and Other Alcoholic Beverages (ANZSIC code 1214)
- Fruit and vegetables (ANZSIC code 1140)

ANZSIC codes and descriptions of the activities included under each code can be found on the Australian Bureau of Statistics website at <u>http://www.abs.gov.au</u>.

Note the definition of raw sugar is as follows:

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

The following is an excerpt from Chapter 17, Section IV, Schedule 3 of the *Customs Tariff Act 1995* 

" "raw sugar" means sugar whose content of sucrose by weight, in the dry state, corresponds to a polarimeter reading of less than 99.55."

As for domestic and commercial wastewater handling facilities, Method 1 for industrial wastewater handling is based on the *National Greenhouse Accounts* methods, except in certain circumstances.

It is intended in time that Reporters will be able to use direct emissions monitoring systems to establish higher capture efficiencies and to establish emissions directly. This will require the development of direct monitoring methods. None have been specified in these Guidelines. Further development work and consultation is required to establish the appropriateness of various monitoring techniques before their inclusion.

(1) For paragraph 5.41(1)(a), method 1 is:

$$\mathbf{E}_{j} = \left[ \mathbf{CH}_{4}^{*} - \gamma (\mathbf{Q}_{cap} + \mathbf{Q}_{flared} + \mathbf{Q}_{tr}) \right]$$

where:

 $E_j$  is the emissions of methane released from the plant during the year measured in CO<sub>2</sub>-e tonnes.

 $CH_4^*$  is the estimated quantity of methane in sludge biogas generated by the plant during the year measured in CO<sub>2</sub>-e tonnes as determined under subsections (2) and (3).

 $\gamma$  is the factor 6.784  $\times$  10<sup>-4</sup>  $\times$  25 converting cubic metres of methane at standard conditions to CO<sub>2</sub>-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:

$$\frac{\gamma \left( \mathbf{Q}_{cap} + \mathbf{Q}_{flared} + \mathbf{Q}_{tr} \right)}{\mathbf{CH}_{4gen}}$$

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<sub>2</sub>-e tonnes.

(3) For subsection (1), if:

$$\frac{\gamma \left( Q_{cap} + Q_{flared} + Q_{tr} \right)}{CH_{4gen}}$$

is greater than 0.75, then:

$$\mathrm{CH}_{4}^{*} = \gamma \left( \mathrm{Q}_{\mathrm{cap}} + \mathrm{Q}_{\mathrm{flared}} + \mathrm{Q}_{\mathrm{tr}} \right) \times \left( \frac{1}{0.75} \right)$$

where:

 $\gamma$  is the factor 6.784 x 10<sup>-4</sup> x 25 converting cubic metres of methane at standard conditions to CO<sub>2</sub>-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:

$$\begin{split} \text{CH}_{4\text{gen}} &= \left(\sum\nolimits_{w,i} \text{COD}_{w,i} ~ - ~ \text{COD}_{sl} ~ - ~ \text{COD}_{\text{eff}}\right) \times ~ \text{MCF}_{ww} ~ \times ~ \text{EF}_{wij} ~ + \\ \left(\text{COD}_{sl} ~ - ~ \text{COD}_{trl} ~ - ~ \text{COD}_{tro}\right) \times ~ \text{MCF}_{sl} ~ \times ~ \text{EF}_{slij} \end{split}$$

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:

$$\text{COD}_{w,i} = \text{Prod}_i \times \text{W}_{\text{gen},i} \times \frac{\text{COD}_{\text{con},i}}{1\ 000}$$

where:

*Prod*<sub>*i*</sub> 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*<sub>st</sub> 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<sub>eff</sub>* 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<sub>trl</sub>* 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*<sub>tro</sub> 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.

 $MCF_{st}$  is the methane correction factor for sludge treated at the plant during the year.

While default MCF values are provided under method 1, it is also possible to self select an appropriate MCF value based on the type of wastewater treatment system employed in the industrial plant. The following table is provided to assist in the MCF selection process.

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<sub>2</sub>-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.

Estim	Estimate of COD for a commodity and industry				
Item	Column 1	Column 2	Column 3		
	Commodity and industry	$W_{gen,i}$	$COD_{con,i}$		
		default value	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		

Estim	Estimate of COD for a commodity and industry					
Item	ItemColumn 1Column 2Column 3					
	Commodity and industry	W <sub>gen,i</sub>	$COD_{con,i}$			
		default value	default value			
8	Fruit and vegetable (ANZSIC code 1140)	20.0	0.2			

(9) For subsection (5), *Prod<sub>i</sub>* 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)

Sections 5.43-5.46 set out Method 2 for wastewater handling. Method 2 requires estimates of Chemical Oxygen Demand concentrations in wastewater estimated using general sampling provisions for these Guidelines and analysis conducted in accordance with listed Australian or international standards or an equivalent standard.

- (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  $COD_{w,i}$  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:

 $COD = 2.6 \times BOD_{5}$ 

- (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)

Section 5.47 sets out Method 3 for wastewater handling. The Method requires estimates of Chemical Oxygen Demand concentrations in wastewater estimated using sampling and analysis conducted in accordance with listed Australian or international standards or an equivalent standard.

- (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

Sections 5.48-5.50 set out Methods 1, 2 and 3 for the flaring of methane in sludge biogas. Method 1 is derived from the methods used for the *National Greenhouse Accounts*. Methods 2 and 3 rely on the sampling and analysis of the fuel to estimate the gas composition of the fuel in order to estimate the quantity of methane flared more accurately.

#### 5.48 Method 1—flaring of methane in sludge biogas

(1) For paragraph 5.41(2)(a), method 1 is:

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

where:

 $E_{j \text{ flared}}$  is the emissions of gas type (*j*) released from flaring of the methane in sludge biogas by the plant during the year measured in CO<sub>2</sub>-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<sub>2</sub>-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<sub>flared</sub>* 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

- 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: (1)

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

where:

 $E_i$  is the emissions of carbon dioxide released from the incineration of waste type (*i*) by the plant during the year measured in CO<sub>2</sub>-e tonnes.

 $Q_i$  is the quantity of waste type (*i*) incinerated by the plant during the year measured in tonnes of wet weight value in accordance with:

- (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.

 $CC_i$  is the carbon content of waste type (*i*).

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

 $OF_i$  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  $CC_i$  in subsection (1), the IPCC default of 0.60 for clinical waste must be used.
- (4) For  $FCC_i$  in subsection (1), the IPCC default of 0.40 for clinical waste must be used.
- (5) For  $OF_i$  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.

The requirement to report the production and consumption of the energy commodities hydrogen, sulphur and uranium does not apply where the hydrogen, uranium, or sulphur is present within another fuel or energy commodity listed in Schedule 1 of the NGER regulations (e.g. hydrogen in natural gas), or where another chemical substance, in which it exists in a molecularly bonded form, is consumed (e.g. sulphur in sulphuric acid).

An example of metering requirements applicable to a region is the *Wholesale Electricity Market Amending Rules* in Western Australia's South West Interconnected System.

The requirements above are generally sourced from definitions contained in the National Electricity Rules and measurement requirements from the *Generator Efficiency Standards* program.

The metering requirements specified in 6.2 (3) apply to the measurement of electricity supplied to an electricity transmission and distribution network measured at the connection point to the network.

Metering requirements are not specified for the amount of electricity produced by the electricity generation unit measured at the unit's terminals or the amount supplied for use outside the facility which is not supplied to the network. Measurement of these

quantities of electricity should make use of existing data and be consistent with the general principles set out in 1.13.

#### 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:

 $Z_i$  is the energy content of fuel type (*i*) produced during the year and measured in gigajoules.

 $Q_i$  is the quantity of fuel type (*i*) produced during the year.

 $EC_i$  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,  $EC_i$  is equal to 0.0036; or
- (d) for fuels measured in gigajoules,  $EC_i$  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.

Estimates of energy produced do not enter emission calculations and will be used for statistical purposes.

### 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.
- Calculating the energy content of fuels and energy commodities consumed is an intermediate step in the estimation of emissions from fuel combustion using methods 1, 2 or 3 in Chapter 2. Consequently this data will serve the dual purpose of providing an estimation of energy consumed and a step in the estimation of emissions.

#### 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  $EC_i$  factor to be estimated under this section in relation to a particular fuel type (*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 *EC<sub>i</sub>* 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.

The requirement to report the production and consumption of the energy commodities hydrogen, sulphur and uranium does not apply where the hydrogen, uranium, or sulphur is present within another fuel or energy commodity listed in Schedule 1 of the NGER regulations (e.g. hydrogen in natural gas), or where another chemical substance, in which it exists in a molecularly bonded form, is consumed (e.g. sulphur in sulphuric acid).

## Chapter 7—Scope 2 emissions

#### 7.1 Application

Chapters 1-5 relate to the estimation of scope 1 emissions.

This chapter concerns scope 2 emissions which 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. This Chapter applies if the amount of purchased electricity consumed from the operation of a facility during a year that result in scope 2 emissions is more than 20 000 kilowatt hours.

Measuring and reporting energy consumption and scope 2 emissions from purchased electricity are optional if the amount purchased that results in scope 2 emissions is less than 20,000 kilowatt hours at a facility. Companies may continue to report these emissions if it is more efficient to do so.

The method is applicable for electricity consumed by transmission and distribution companies, consistent with *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard* of the World Resources Institute/World Business Council for Sustainable Development (the GHG Protocol). The method accommodates electricity measured either in kilowatt hours or gigajoules.

Scope 2 emissions factors are be updated each year.

Scope 2 emissions also arise from electricity acquired from off-grid sources that do not form part of the facility. These Scope 2 emissions may be estimated using section 7.3 below. Emission factors can be provided by the supplier of the electricity, or if unavailable, the emission factor for NT may be used. NT electricity generation primarily represents a mix of natural gas and diesel generation which is a reasonable match for the fuel mix used in the generation of off-grid electricity generation.

- (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<sub>2</sub>-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<sub>2</sub>-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<sub>2</sub>-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<sub>2</sub>-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.

# Table 7.2Indirect (scope 2) emission factors from<br/>consumption of purchased electricity from a grid

kg CO <sub>2</sub> -e/kW	h
77 New South Wales and Australian Capital Territory	0.83
78 Victoria	1.08
79 Queensland	0.79
80 South Australia	0.49
81 South West Interconnected System in Western Australia	0.70
82 Tasmania	0.14
83 Northern Territory	0.64

Chapter 7 - Scope 2 emissions

#### **Other Scope 2 Emissions**

Scope 2 emissions also arise from heating, cooling, or steam acquired from outside the facility.

These Scope 2 emissions may be estimated in consultation with the vendor of the heating, cooling or steam to ensure consistency and completeness with the vendor's estimates of scope 1 emissions for those energy commodities.

#### Example A

A company has operations in NSW and Queensland. A component of the company's energy use is electricity purchased from the grid. During the year the NSW operations consumed 11,300,000 kWh of electricity, while the Queensland operations consumed 14,600,000 kWh. Emissions are estimated as follows:

$$Y = Q \ge EF/1000$$

where:

Y is the scope 2 emissions.

Q is the quantity of electricity purchased from the electricity grid measured in kilowatt hours. In this case, 11,300,000 kWh from NSW and 14,600,000 kWh from QLD.

EF is the scope 2 emission factor, in either kilograms of  $CO_2$  e emissions per kilowatt hour for the State or Territory in which the consumption occurs as specified in Part 6 of Schedule 1 (of the Determination). In this case it is 0.83 kg  $CO_2$ -e/kWh for NSW and 0.79  $CO_2$ -e/kWh for QLD.

Therefore, to calculate Scope 2 emissions:

For NSW operations

=(11,300,000 x 0.83)/1000

For QLD operations

=(14,600,000 x 0.79)/1000

= 11,534 t Scope 2 CO<sub>2</sub>-е

#### Example B

A company uses steam from another facility to provide heat and returns condensate back to the other facility. During the year the company consumed 5,700 gigajoules of energy from the steam. Emissions are estimated as follows:

 $Y = Q \ x \ EF/1000$ 

where:

Y is the scope 2 emissions.

Q is the quantity of steam purchased from the other facility. In this case the quantity of steam purchased is 5,700 GJ.

EF is the scope 2 emission factor for the steam, in this case measured in kg CO<sub>2</sub>-e/GJ. The vendor has provided a scope 2 emission factor for the steam of 400 kg CO<sub>2</sub>-e/GJ.

Therefore, to calculate Scope 2 emissions:

Scope 2 emissions

 $= (5,700 \times 400) / 1000$ 

 $= 2280 t \text{ Scope } 2 \text{ CO}_2\text{-e}$ 

The scope 2 emission factors are state-based emission factors from on-grid electricity generation calculated systematically from the physical characteristics of the electricity grid. The state-based emission factor calculates an average emission factor for all electricity consumed from the grid in a given state, territory or electricity grid. All emissions attributable to a state territory or grid's electricity consumption are allocated amongst individual consumers in proportion to their relative level of consumption. In effect, the likelihood of a particular generator supplying a particular consumer is assumed to reflect each generator's relative level of supply to the grid. The reason for this approach is that within an electricity grid it is impossible to physically trace or control the actual physical source of electricity received by each customer.

This approach minimises information requirements for the system and produces factors that are relatively easy to interpret and apply, and which are used to support a

range of specific government programs and policies. Consistent adoption of these 'physical' state-based emission factors ensures the emissions generated in each state are fully accounted for by the end-users of the purchased electricity and double counting is avoided.

It is recognised that this approach does not serve all possible policy purposes and that alternative, more data-intensive approaches are possible. Reporters will be able to provide additional data on a voluntary basis on consumption of certain renewable products.

#### Background to Scope 2 factor estimates

The scope 2 emission factors reflect data that are based on:

- on-grid activity only;
- state-based activity;
- annual financial year averages;
- physical characteristics of the electricity supply and demand.

The estimated electricity emission factors have been aligned with the definitions used in *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard* of the World Resources Institute/World Business Council for Sustainable Development (the GHG Protocol).

The emission factor for scope 2 is defined in terms of energy sent out on the grid rather than energy delivered because this effectively ensures that end users of electricity are allocated only the scope 2 emissions attributable to the electricity they consume and not the scope 2 emissions attributable to electricity lost in transmission and distribution. The latter are allocated to the transmission and distribution network. This follows the GHG Protocol guidance that scope 2 emissions be reported by the organisation owning or controlling the plant or equipment where the electricity is consumed. Companies that own or control transmission and distribution networks report their transmission and distribution loss emissions under scope 2.

The emission factors are calculated as financial year averages based on electricity generation within each state and territory and take into account interstate electricity

flows (where they exist) and the emissions attributable to those flows. To reduce volatility scope 2 emission factors are calculated as a three-year moving average.

Scope 2 emissions result from the generation of purchased electricity from each state's electricity grid. The emission factor at generation (*EFG scope2<sup>t</sup>*) is used to calculate scope 2 emissions and is defined for state i and financial year t:

 $EFG \ scope2_i^t = \frac{Combustion \ emissions \ from \ electricit \ y \ consumed \ from \ the \ grid \ in \ state \ i \ (CE_C_i^t)}{Electricit \ y \ sent \ out \ consumed \ from \ the \ grid \ in \ state \ i \ (ESO_C_i^t)}$ 

Where

'combustion emissions from electricity consumed from the grid in state i' (CE\_C<sub>ti</sub>) and 'energy sent out consumed from the grid in state i' (ESO\_C<sub>ti</sub>) are defined in terms of the state's electricity grid generation, imports and exports as follows:

$$CE\_C_{i}^{t} = CE\_P_{i}^{t} + \sum_{i}^{j} \left(\frac{ESO\_M_{j,i}^{t}}{ESO\_P_{j}^{t}} \times CE\_P_{j}^{t}\right) - \sum_{i}^{k} \left(\frac{ESO\_X_{i,k}^{t}}{ESO\_P_{i}^{t}} \times CE\_P_{i}^{t}\right)$$
$$ESO\_C_{i}^{t} = ESO\_P_{i}^{t} + \sum_{i}^{j} ESO\_M_{j,i}^{t} - \sum_{i}^{k} ESO\_X_{i,k}^{t}$$

#### where

 $CE_P_{ti}$  is the total  $CO_2$ -e emissions from fuel combustion at generation attributed to the electricity generated/produced for the grid in state i in financial year t

 $CE_P_{tj}$  is the total  $CO_2$ -e emissions from fuel combustion at generation attributed to the electricity generated for the grid in state j in financial year t

 $ESO_M_{tj,i}$  is the imports of energy sent out from state j to state i in financial year t. Imports are calculated from the interregional flows of electricity across the interconnectors published by the National Electricity Market Management Company (NEMMCO)

 $ESO_X_{ti,k}$  is the exports of energy sent out from state i to state k in financial year t. Exports are calculated from the inter-regional flows of electricity across the interconnectors published by NEMMCO

 $ESO_P_{tj}$  is the total energy sent out on the grid that is generated within state j in financial year t

 $ESO_{P_{ti}}$  is total energy sent out on the grid that is generated within state i in financial year t

The estimated 'Scope 2' emission factors for consumption of purchased electricity use data obtained under the National Greenhouse and Energy Reporting Act and is supplemented with data from the Australian Energy Market Operator, ABARE and the Australian Energy Council. Emission estimates are taken from the National Greenhouse Accounts. Further detail on the approach to calculating electricity emission estimates is available in the *National Inventory Report 2015*.

## **Chapter 8—Assessment of uncertainty**

Proposed changes to the NGER Regulations will only require reporters with emissions of more than 25 kilotonnes of CO<sub>2</sub>-e from the combustion of a fuel type, or a source other than fuel combustion to calculate and report the statistical uncertainty associated with their scope 1 emissions. Sources are defined in section 1.10 of the Measurement Determination and fuel types are set out in Schedule 1 of the NGER Regulations.

## Part 8.1—Preliminary

The GHG Protocol guidance on uncertainty assessment in GHG inventories and calculating statistical parameter uncertainty (September 2003) v1.0 (the uncertainty protocol) is the source document for the methodology of calculating uncertainty under NGERS. It is referred to in this chapter as *the uncertainty protocol*.

This document is produced by the World Resources Institute and the World Business Council on Sustainable Development and is available at <u>http://www.ghgprotocol.org/calculation-tools/all-tools</u> and has detailed information about the calculation of uncertainty in greenhouse gas inventories.

There are a number of different sources of uncertainty identified in the uncertainty protocol – however corporations are only asked to estimate the statistical uncertainty. This type of uncertainty results from natural variations (for example, random human errors in the measurement process and fluctuations in measurement equipment). More information is provided in the uncertainty protocol.

Proposed ammendments to the NGER Regulations will require only reporters with the largest sources of emissions (25,000 tonnes of CO2-e or over) to calculate and report the statistical uncertainty associated with emissions reporting.

#### 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

Note that there is a difference in meaning between the common usage of the word 'confidence' and its statistical usage in relation to '95% confidence interval'. In natural science and technical experiments it is often standard practice to estimate uncertainty at the 95% confidence interval. The 'confidence interval' is defined by a probability value (in this case a probability of 95%) and confidence limits on either side of the mean value.

This means that the uncertainty level (the +/- percentages – otherwise known as the confidence limits) is to be calculated so that there is a 95% probability that the true value of the estimate is encompassed by the estimated uncertainty levels (the confidence limits). For example, an emission estimate of 100kt +/- 10% at the 95% confidence interval means that the true value lies between 90kt and 110kt with a probability of 95%.

#### 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

The calculation of uncertainty for a registered corporation should take into account the uncertainty associated with all the sources of emissions reported by the corporation. The uncertainty associated with each emission source is to be aggregated to the "subtotal" of uncertainty at the facility level and the uncertainty associated with each facility if to be aggregated to the "total" of uncertainty at the corporation level.

In the calculation of uncertainty, it is important that the corporation calculates their uncertainty at the same level of disaggregation to which the emission estimate was calculated. For example, if a facility uses multiple types and qualities of a fuel (e.g. different types of coals) for which it has data on, and the emission calculation incorporates the data on each different fuel types, then the uncertainty calculation should also be performed at the same level of disaggregation. In other words, the uncertainty calculation should incorporate uncertainty data on the different fuel types at the same level of detail that was performed in the emission calculation.

- (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 uncertaint y level (%)	Carbon dioxide emission factor uncertaint y level (%)
1	Bituminous coal	28	5

Item	Fuel Combusted	Energy content uncertaint y level (%)	Carbon dioxide emission factor uncertaint y level (%)
1A	Sub-bituminous coal	28	5
1B	Anthracite	28	5
2	Brown coal	50	12
3	Coking coal	12	7
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

Item	Fuel Combusted	Energy content uncertaint y level (%)	Carbon dioxide emission factor uncertaint y level (%)
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
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:	18	2
	(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		
50	Biodiesel	50	NA

Item	Fuel Combusted	Energy content uncertaint y level (%)	Carbon dioxide emission factor uncertaint y level (%)
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	Uncertai (%)	Uncertainty levels for quantities of fuel combusted (%)		
		Criterion used for estimation of quantity of fuel combusted		tity of fuel	
		Α	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

Note that the uncertainty levels in this section are the aggregate uncertainty levels for the source and may be used by substituting directly into the aggregation equations for facilities and the corporation in sections 8.12 and 8.13 as appropriate. Default individual parameter uncertainties have not been provided for fugitive emissions that are calculated under method 1 and hence the parameter aggregation equation in section 8.11 is not applicable when these defaults are used.

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
1	Underground mines	50

Item	Sources	Aggregated uncertainty level (%)
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 uncertaint y level (%)	Activity data uncertaint y (%)
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
Item	Industrial process sources	Emission factor uncertaint y level (%)	Activity data uncertaint y (%)
------	-----------------------------------------------------------------	-------------------------------------------------	-----------------------------------------
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.

For aluminium production the uncertainty for estimates of emissions may be assessed using the information provided in Chapter 4 of the 2006 IPCC Guidelines for National Greenhouse Gas Inventories (Volume 3).

Item	Industrial process sources	Aggregated uncertainty level (%)
1	Emissions of hydrofluorocarbons and sulphur hexafluoride gas	30

Note that the above uncertainty level is the aggregate uncertainty level for the source (Emissions of hydrofluorocarbons and sulphur hexafluoride gas) and may be used by substituting directly into the aggregation equations for facilities and the corporation in sections 8.12 and 8.13 as appropriate. Default individual parameter uncertainties have not been provided for this emission source calculated under method 1 and hence the parameter aggregation equation in section 8.11 is not applicable when the above default is used.

- (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

Note that the uncertainty levels in this section are the aggregate uncertainty levels for the source and may be used by substituting directly into the aggregation equations for facilities and the corporation in sections 8.12 and 8.13 as appropriate. Default individual parameter uncertainties have not been provided for waste sector emissions calculated under method 1 and hence the parameter aggregation equation in section 8.11 is not applicable when these defaults are used.

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

The technique used in this chapter for aggregating the uncertainty is known as first order error propagation. Further information and guidance is given in the uncertainty protocol and its reference documents. There are four key assumptions that are made when this technique is used and should be considered when applying these formulas which are:

- 1. The error in each parameter is normally distributed
- 2. There are no biases in the estimator function, (i.e. the estimated value is the mean value)
- 3. The estimated parameters are uncorrelated
- 4. Individual uncertainties in each parameter must be less than 60% of the mean

In most cases it will be reasonable to assume that the above conditions are satisfied and that any uncertainty calculation will be reasonable.

(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.

The technique described in the *GHG uncertainty protocol* to be applied when methods 2, 3 and 4 are used to estimate emissions is similar to the technique outlined for the calculation of uncertainty for method 1. The key difference is that the parameter uncertainties should be estimated directly rather than taken from the default tables in sections 8.6 to 8.10. Techniques for estimating these parameters are given in section 7 of the uncertainty protocol. Also, further guidance and discussion on calculation of uncertainty is given in uncertainty protocol.

Generally, the uncertainties estimated under the higher order methods 2, 3 and 4 are likely to be lower than those calculated under method 1, indicating that the emission estimate using the higher order methods is more accurate than that calculated under method 1. The main reason for this is that in method 1 default energy content factors are used and there is significant uncertainty around these defaults, particularly for solid fuels such as coal (note that electricity generators are required to use methods 2 or higher for emissions estimates). Higher order methods of analysis require direct analysis of the fuel giving a much more accurate estimation of the carbon content of fuels and hence the emissions.

#### Example

Estimates of emissions and uncertainty for the same corporation (combusting the same estimated fuel quantities) are now given using method 2. The parameters used in the method 2 emissions calculation are different to that of method 1 and the source of parameter uncertainty is estimated by the corporation (rather than taken from tables). Note that calculations for aggregating uncertainties are similar to those for method 1 and guidance is given in the uncertainty protocol.

Note that guidance on estimating the parameter uncertainties is given in section 7 of the GHG protocol, (although item 4 in the list of available methods in section 7 is not to be used).

Facility 1								
Combustion of Diesel Oil	Q - kL	% carbon	Fuel density kg/kL	EC	OF	Constant	EF	Emission (tonnes)
	1,000	85.2	850	38.6	0.99	3.664	68.1	2,627
Uncertainty	1.5%	1.5%	1.0%	NA	0.0%	NA	1.8%	2.3%
Source of Uncertainty	а	b	С	d	е	f	g	g
Combustion of Black	Q - t	% carbon		EC	OF	Constant	EF	Emission
Coal	5,000	62.2	NA	27	0.98	3.664	82.7	11,167
Uncertainty	2.5%	3.0%	NA	NA	0.0%	NA	3.0%	3.9%
Source of Uncertainty	а	b		d	е	f	g	g
Facility 1 Subtotal							13,794	
Uncertainty							3.2%	
Source of Uncertainty								h

Facility 2								
Combustion of Natural Gas	Q - m3	Gas Composition	Fuel density kg/m3	EC	OF	Constant	EF	Emission
	9,000,000	NA	0.74	0.0393	0.995	2.743	51.4	18,178
Uncertainty	1.5%	3.0%	1.0%	NA	0.0%	NA	3.2%	3.5%
Source of Uncertainty	а	i	С	d	е	f	g	G

Combustion of Gasoline	Q - kL	% carbon	Fuel density kg/kL	EC	OF	Constant	EF	Emission
	3,000	85.2	720	34.2	0.99	3.664	65.1	6,676
Uncertainty	1.5%	2.0%	1.0%	NA	0.0%	NA	2.2%	2.7%
Source of Uncertainty	а	b	С	d	е	f	g	G
Facility 2 Subtotal								24,854
Uncertainty								2.7%
Source of Uncertainty								Н

Corporation Total - CO <sub>2</sub> emissions	38,648
Uncertainty	2.1%
Source of Uncertainty	Н

Corporation Total CH <sub>4</sub> and N20 emissions - kg CO <sub>2</sub> -e (using method 1)	130
Uncertainty level	22.1%
Source of Uncertainty Assessment - Similar to CO <sub>2</sub> Calculations for method 1	

Corporation Total CO <sub>2</sub> -e emissions	38,778
Uncertainty level	2.0%
Source of Uncertainty Assessment	Н

Notes:

a Uncertainty potentially assessed on fuel measurement instrument precision. Fuel use from stockpiles, for example, may generate larger uncertainties which may need to be considered.

- b Sampling and analysis uncertainty, either through instrument precision or other statistical method
- c Uncertainty associated with fuel density from sampling and analysis
- d Uncertainty associated with energy content not relevant to method 2 since energy content factor falls out in calculation of emissions
- e Uncertainty associated with the oxidation factor assumed to be zero in these cases though may be incorporated in an uncertainty calculation where considered significant
- f Uncertainty associated with these molecular mass constants is not statistical uncertainty as defined by the uncertainty protocol and hence is not incorporated
- g This uncertainty is aggregated using the method in section 7 of the uncertainty protocol
- h This uncertainty is aggregated using the method in section 8 of the uncertainty protocol
- i Sampling and analysis uncertainty of gas composition (assumed to be 100% methane in the emission calculation)

### Appendix A: 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.

*Note 3* 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.

*Note 4* The default carbon content factors are not separately listed for sub bituminous coal, bituminous coal and anthracite in the table below, however they can be derived using the respective default emission factors and energy content factors published in the Determination.

Carbon content factors are estimated from the  $CO_2$  emission factor, the oxidation factor and the energy content factor of fuels.

#### Part 1 Solid fuels and certain coal-based products

ltem	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

ltem	Fuel type	Carbon content factor tC/t fuel
9	Non-biomass municipal materials, if recycled and combusted to produce heat or electricity	0.250
Prim	ary 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

ltem	Fuel type	Carbon content factor
		(tC/m <sup>3</sup> of fuel unless otherwise specified)
Gase	ous fossil fuels	
17	Natural gas if distributed in a pipeline	$5.52 \times 10^{-4}$
17A	<ul><li>Natural gas, if:</li><li>(a) distributed in a pipeline; and</li><li>(b) measured in units of gigajoules only</li></ul>	$1.40 \times 10^{-2} \text{ tC/GJ}$ of fuel
18	Coal seam methane that is captured for combustion	$5.29  imes 10^{-4}$
19	Coal mine waste gas that is captured for combustion	$5.34 \times 10^{-4}$
20	Compressed natural gas that has reverted to standard conditions	$5.52 \times 10^{-4}$
21	Unprocessed natural gas	$5.52 \times 10^{-4}$
22	Ethane	$9.70  imes 10^{-4}$
23	Coke oven gas	$1.83  imes 10^{-4}$

ltem	Fuel type	Carbon content factor (tC/m <sup>3</sup> of fuel
		specified)
24	Blast furnace gas	$2.55 \times 10^{-4}$
25	Town gas	$6.41  imes 10^{-4}$
26	Liquefied natural gas	0.355 tC/kL of fuel
27	Gaseous fossil fuels other than those mentioned in items 17 to 26	$5.52 \times 10^{-4}$
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

ltem	Fuel type	Carbon content factor (tC/kL of fuel unless otherwise specified)
Petro	oleum 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

ltem	Fuel type	Carbon content factor
		(tC/kL of fuel unless otherwise specified)
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	0.597
46	Petroleum coke	0.856 tC/t fuel
47	Refinery gas and liquids	0.641 tC/t fuel
48	Refinery coke	0.856 tC/t fuel
49	Bitumen	0.951 tC/t fuel
50	Waxes	0.871 tC/t fuel
51	<ul> <li>Petroleum based products other than:</li> <li>(a) petroleum based oils and petroleum based greases mentioned in items 31 and 32; and</li> </ul>	0.654
	(b) the petroleum based products mentioned in items 33 to 50	
Biofuels		
52	Biodiesel	0
53	Ethanol for use as a fuel in an internal combustion engine	0

# Part 4 Petrochemical feedstocks and products

Biofuels other than those mentioned in items 52 and 53

54

ltem	Fuel type	Carbon content
		factor
		(tC/t fuel
		unless otherwise
		specified)
Petrochemical feedstocks		
55	Carbon black if used as a petrochemical feedstock	1

0

ltem	Fuel type	Carbon content factor (tC/t fuel unless otherwise specified)
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

ltem	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

#### **Notes on Carbon Content Factors**

1. Energy value: Source – ABARE<sub>1</sub> (washed steaming). CO<sub>2</sub> emission factor: Source - National Inventory Report 2006, Department of Climate Change.

 1A. Energy value: Source – ABARE<sub>1</sub> (washed steaming). CO<sub>2</sub> emission factor: Source - National Inventory Report 2006, Department of Climate Change.  1B. Energy value: Source – ABARE<sub>1</sub> (washed steaming). CO<sub>2</sub> emission factor: Source - National Inventory Report 2006, Department of Climate Change.

Energy value: Source - AGEIS database, Department of Climate Change and Energy
 Efficiency (based on facility reports). CO<sub>2</sub> emission factor: Source - AGEIS database, Department of
 Climate Change and Energy Efficiency (based on facility reports).

3. Energy value: Source – ABARE<sub>1</sub> (washed coking). CO<sub>2</sub> emission factor: Source - National Inventory Report 2006, Department of Climate Change.

4. Energy value: Source – ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source - AGEIS database, Department of Climate Change and Energy Efficiency (based on facility reports).

Energy value: Source – ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source – National Inventory Report
 2006, Department of Climate Change.

Energy value: Source – ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source – National Inventory Report
 2006, Department of Climate Change (coal tar).

7. See (4)

Energy value: Source – GHD Review of Sectoral Models, Internal report to the AGO, 2006.
 CO<sub>2</sub> emission factor: Source – National Inventory Report 2006, Department of Climate Change.

9. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. CO<sub>2</sub> emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.

10. Energy value: Source: ABARE<sub>1</sub> (dry wood).

11. Energy value: Source: ABARE<sub>1</sub> (green wood).

12. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value.

13. Energy value: Source: ABARE<sub>1</sub>.

14. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value.

15. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value.

16. See (14)

17. Energy value: Source: ABARE<sub>1</sub> (weighted average). CO<sub>2</sub> emission factor: Source - AGEIS database, Department of Climate Change and Energy Efficiency.

17A Energy value: Source: ABARE1 (weighted average). CO<sub>2</sub> emission factor: Source - AGEIS database, Department of Climate Change and Energy Efficiency.

Energy value: Source: ABARE<sub>1</sub> (coal seam methane). CO<sub>2</sub> emission factor: Source - AGEIS database, Department of Climate Change and Energy Efficiency.

Energy value: Source: ABARE<sub>1</sub> (coal seam methane). CO<sub>2</sub> emission factor: Source - AGEIS database, Department of Climate Change and Energy Efficiency.

20. See (17)

21. See (17)

22. Energy value: Source: ABARE<sub>1</sub> (average). CO<sub>2</sub> emission factor: Source – National Inventory Report 2008, Department of Climate Change and Energy Efficiency (forthcoming).

Energy value: Source: ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source – National Inventory Report
 2006, Department of Climate Change.

24. Energy value: Source – ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source: IPCC 2006. Derived using conversion factor of 0.90.

25. Energy value: Source – ABARE<sub>2</sub> (synthetic natural gas). CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change.

26. Energy value: Source – ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source - AGEIS database, Department of Climate Change and Energy Efficiency.

27. See (17)

28. Energy value: Source – ABARE<sub>1</sub>.

29. Energy value: Source – ABARE<sub>1</sub>.

30. See (28)

31. Energy value: Source – ABARE<sub>2</sub> (lubricants and greases). CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change (lubricants and greases).

32. Energy value: Source – ABARE<sub>2</sub> (lubricants and greases). CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change (lubricants and greases).

Energy value: Source – ABARE<sub>2</sub> (weighted average). CO<sub>2</sub> emission factor: Source: IPCC
 2006. Derived using conversion factor of 0.95.

34. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. CO<sub>2</sub> emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.

Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.

Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.

37. Energy value: Source – ABARE<sub>2</sub> (power kerosene). CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change.

Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.

Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.

40. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.

41. Energy value: Source – ABARE<sub>2</sub> (low sulphur). CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change. Derived using conversion factor of 0.95.

42. Energy value: Source – ABARE<sub>2</sub>. Given same energy content as solvents. CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change (assumed same as solvents).

 Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: National Inventory Report 2006, Department of Climate Change.

44. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change. .

45. Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change.

46. Energy value: Source – IPCC 2006. CO<sub>2</sub> emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.

47. Energy value: Source – ABARE<sub>1</sub> (refinery fuel). CO<sub>2</sub> emission factor: Source: IPCC 2006.Derived using conversion factor of 0.95.

48. See (46)

49. Energy value: Source – ABARE<sub>1</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change.

Energy value: Source – ABARE<sub>2</sub>. CO<sub>2</sub> emission factor: Source: National Inventory Report
 2006, Department of Climate Change (assumed same as solvents).

51. Energy value: Source – ABARE<sub>2</sub>. Based on IPCC 2006, given same energy content as solvents. CO<sub>2</sub> emission factor: Source: National Inventory Report 2006, Department of Climate Change (set same as solvents).

52. Energy value: Source – Derived from US Department of Energy. Non-CO<sub>2</sub> factors: IPCC
 2006. Derived using conversion factor 0.95.

53. Energy value: Source – ABARE<sub>2</sub>. Non-CO<sub>2</sub> factors: IPCC 2006. Derived using conversion factor 0.95.

54. See (53).

55. Assumed to be 100% carbon

56. Carbon content obtained through stoichiometric estimation

- 57. Carbon content assumed the same as ethylene
- 58. Carbon content obtained through stoichiometric estimation
- 59. Carbon content obtained through stoichiometric estimation
- 60. Carbon content obtained through stoichiometric estimation
- 61. Carbon content obtained through stoichiometric estimation

- 62. Carbon content obtained through stoichiometric estimation
- 63. Carbon content obtained through stoichiometric estimation
- 64. Carbon content obtained through stoichiometric estimation
- 65. Carbon content obtained through stoichiometric estimation
- 66. Carbon content obtained through stoichiometric estimation

Notes:

- ABARE<sub>1</sub> 2007 *Fuel and Electricity Survey Fuel Codes,* Australian Bureau of Agricultural and Resource Economics <u>www.abareconomics.com/publications\_html/surveys/surveys/surveys.html</u>, Commonwealth of Australia, Canberra.
- ABARE<sub>2</sub> 2007 *Energy in Australia 2006*, produced for Department of Industry, Tourism and Resources, pages 77-79, Commonwealth of Australia, Canberra.

Department of Climate Change and Energy Efficiency (2008), *National Inventory Report 2006*, Commonwealth of Australia, Canberra

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

## Appendix B: Definitions and interpretation

#### Definitions

**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 <u>www.api.org</u>.

*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*<sub>2</sub>-*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.

*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  $1.95 \text{ g/cm}^3$ .

*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).

#### Interpretation

*Ethanol* is the part of the fuel that relates to the quantities of biofuel and not to the total volume of liquids into which the biofuels are blended. Emission and energy content factors for ethanol apply to pure ethanol and not 'denatured' ethanol.

*Liquefied petroleum gas* are derived from refinery processes, crude oil stabilisation plants and natural gas processing plants, comprising propane, butane or a combination of the two. They are normally liquefied under pressure for transportation and storage.

*Coal seam methane that is captured for combustion* can be applied to a pipeline containing natural gas. If consumers are unable to determine whether the natural gas distributed in a pipeline is natural gas or coal seam methane then it is reasonable to report the fuel consumption as natural gas distributed in a pipeline.

# Appendix C: Global Warming Potentials, Units and Conversions

#### **Global Warming Potentials**

Greenhouse Gas	Chemical Formula	Global Warming
		Potential (GWP)
Carbon dioxide	CO <sub>2</sub>	1
Methane	CH <sub>4</sub>	25
Nitrous oxide	$N_2O$	298
Sulphur hexafluoride	SF <sub>6</sub>	22 800
HFC-23	CHF₃	14 800
HFC-32	$CH_2F_2$	675
HFC-41	CH <sub>3</sub> F <sub>2</sub>	92
HFC-43-10mee	$C_5H_2F_{10}$	1 640
HFC-125	$C_2HF_5$	3 500
HFC-134	C <sub>2</sub> H <sub>2</sub> F <sub>4</sub> (CHF <sub>2</sub> CHF <sub>2</sub> )	1 100
HFC-134a	C <sub>2</sub> H <sub>2</sub> F <sub>4</sub> (CH <sub>2</sub> FCF <sub>3</sub> )	1 430
HFC-143	C <sub>2</sub> H <sub>3</sub> F <sub>3</sub> (CHF <sub>2</sub> CH <sub>2</sub> F)	353
HFC-143a	C <sub>2</sub> H <sub>3</sub> F <sub>3</sub> (CF <sub>3</sub> CH <sub>3</sub> )	4 470
HFC-152a	C <sub>2</sub> H <sub>4</sub> F <sub>2</sub> (CH <sub>3</sub> CHF <sub>2</sub> )	124
HFC-227ea	C <sub>3</sub> HF <sub>7</sub>	3 220
HFC-236fa	$C_3H_2F_6$	9 810
HFC-245ca	$C_3H_3F_5$	693
Perfluoromethane (tetrafluoromethane)	CF4	7 390
Perfluoroethane (hexafluoroethane)	C <sub>2</sub> F <sub>6</sub>	12 200
Perfluoropropane	C <sub>3</sub> F <sub>8</sub>	8 830
Perfluorobutane	C <sub>4</sub> F <sub>10</sub>	8 860
Perfluorocyclobutane	c-C <sub>4</sub> F <sub>8</sub>	10 300
Perfluoropentane	C <sub>5</sub> F <sub>12</sub>	9 160
Perfluorohexane	C <sub>6</sub> F <sub>14</sub>	9 300

Note 1: Global Warming Potential (also known as GWP) is defined in the Glossary published by the UNFCCC as an index representing the combined effect of the differing times greenhouse gases remain in the atmosphere and their relative effectiveness in absorbing outgoing infrared radiation.

Note 2: The Global Warming Potential figures in the above table are the figures published by the Intergovernmental Panel on Climate Change in Climate Change 2007: The Physical Science Basis (Cambridge, UK: Cambridge University Press, 2007).
#### Metric prefixes

Prefix	Abbreviation	Symbol
Peta (million billion [thousand trillion])	10 <sup>15</sup> (10 <sup>6</sup> x10 <sup>9</sup> )	Р
Tera (thousand billion [trillion])	10 <sup>12</sup> (10 <sup>3</sup> x10 <sup>9</sup> )	Т
Giga (billion)	10 <sup>9</sup>	G
Mega (million)	10 <sup>6</sup>	М
kilo (thousand)	10 <sup>3</sup>	k
hecto	10 <sup>2</sup>	h
deca	10 <sup>1</sup>	da
- (e.g. gram)	10 <sup>0</sup>	g
deci	10-1	d
centi	10-2	с
milli	10-3	m
micro	10-6	μ
nano	10 <sup>-9</sup>	n
pico	10 <sup>-12</sup>	р

#### Unit equivalences

1015 grams (Petagram)	Gigatonne (Gt)
1012 grams (Teragram)	Megatonne (Mt)
10 <sup>9</sup> grams (Gigagram)	kilotonnes (kt) (10 <sup>3</sup> tonnes)
10 <sup>6</sup> grams (million grams)	1 tonne
kg/GJ (10 <sup>3</sup> g/10 <sup>9</sup> J)	Gg/PJ (10 <sup>9</sup> g/10 <sup>15</sup> J)
Mg/PJ (10 <sup>6</sup> g/1015J)	g/GJ 10ºg/10ºJ)

For example: 423,000 Gg is equivalent to 423,000 kt and to 423 Mt

# Energy and power units

Unit of energy: Joule

Unit of power (rate of energy usage): Watt

#### **Energy conversion factors**

Conversion factors				
1 Watt		= 1 joule per second		
3600 Watt-seconds		= 1 Watt-hour (3600 seconds in one hour)		
1 Watt-hour		= 3600 joules		
1000 Watt-hours		= 1 Kilowatt hour (kWh)		
1 kWh		= 3.6 x 10 <sup>6</sup> joules = 3.6 mega joules		
1 kWh		= 3.6 x 10 <sup>-3</sup> GJ		
1 GJ		= 278 kWh		
1 PJ		= 278 x 10 <sup>6</sup> kWh = 278 GWh		
(A) For conversion from first unit to second unit:	(B) Multiply quantity in first unit by conversion factor:		(C) To calculate quantity in second unit:	
kWh to J	kWh x 3.6 x 10 <sup>6</sup>		Joules	
J to kWh	J x 1/3.6 x 10 <sup>-6</sup>		kWh	
kWh to MJ	kWh x 3.6		MJ	
MJ to kWh	MJ x 0.278		kWh	
kWh to GJ	kWh x 3.6 x 10 <sup>-3</sup>		GJ	
GJ to kWh	GJ x 278		kWh	
kWh to PJ	kWh x 3.6 x 10 <sup>-9</sup>		PJ	
PJ to kWh	PJ x 278 x 10 <sup>6</sup>		kWh	

# Municipal solid waste volume to weight conversion factors

Material type	Volume to weight
Paper	0.09
Textiles	0.14
Wood	0.15

Garden	0.24
Food	0.50
Co-mingled	0.12

Note: Volume to weight conversions is an inexact science and conversion factors change if materials are compacted.

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