NATIONAL GREENHOUSE AND ENERGY REPORTING (MEASUREMENT) DETERMINATION (2008)

EXPLANATORY STATEMENT

Issued by the Authority of the Minister for Climate Change and Water,
Senator the Honourable Penny Wong

National Greenhouse and Energy Reporting Act 2007

National Greenhouse and Energy Reporting (Measurement) Determination 2008

The *National Greenhouse and Energy Reporting Act 2007* (the Act) establishes the National Greenhouse and Energy Reporting System which is a national framework for reporting greenhouse gas emissions, greenhouse gas projects (abatement actions) and energy consumption and production by Australian corporations.

This Instrument is made under subsection 10 (3) of the National Greenhouse and Energy Reporting Act 2007 which provides for the Minister to determine methods, or criteria for methods, for the measurement of:

(a) greenhouse gas emissions;

(b) the production of energy;

(c) the consumption of energy.

Data reported under the Act using the Methods set out in this Instrument will inform decision making during the establishment and on-going implementation of the emissions trading scheme, assist Australia to meet its international reporting obligations, inform government policy and programs and inform the Australian public.

The Instrument provides necessary details that will enable corporations to comply with the *National Greenhouse and Energy Reporting Regulations 2008* under the Act. Details of the proposed Instrument are set out in the Attachment A.

The Instrument forms part of the outcomes of comprehensive consultation with business and other stakeholders between May 2005 and June 2008 in relation to the Act, the regulations under the Act and the Instrument itself.

Instrument specific consultation began after the Act was passed in September 2007. In January 2008 the Department of Climate Change released for public comment the *National Greenhouse and Energy Reporting System, Technical Guidelines for the Estimation of Greenhouse Emissions and Energy at Facility-level: Energy, Industrial*

Process and Waste Sectors in Australia - Overview Paper and the *National Greenhouse and Energy Reporting System, Technical Guidelines for the Estimation of Greenhouse Emissions and Energy at Facility-level: Energy, Industrial Process and Waste Sectors in Australia - Discussion Paper.*

These documents contained preliminary proposals for the Instrument to be made under the National Greenhouse and Energy Reporting Regulations 2008. Over 70 formal submissions were received from interested organisations and individuals.

Feedback was provided through a 'Frequently Asked Questions' document that was published on the Department of Climate Change website in April 2008.

Most recently the proposed Instrument was provided to a group of industry organisations and businesses that had actively engaged in the development of the system for review and to provide feedback on how the proposed instrument practically reflected the stated policy intent.

The Instrument would be a legislative instrument for the purposes of the *Legislative Instruments Act 2003*.

The Instrument will commence 1 July 2008.

ATTACHMENT A

National Greenhouse and Energy Reporting (Measurement) Determination 2008

CHAPTER 1 General

Division 1.1.1 Overview

The National Greenhouse and Energy Reporting Act 2007 (‘the Act’) established the legislative framework for a national greenhouse and energy reporting system.

The Act provides for an integrated reporting system that will provide the basis for:

- informing government policy formulation and the Australian public;
- meeting Australia’s international reporting obligations;
- assisting Commonwealth, State and Territory government programs and activities;
- underpinning the introduction of an emissions trading scheme in the future; and
- avoiding duplication of similar reporting requirements in the States and Territories..

The Act makes reporting mandatory for corporations whose energy production, energy use, or greenhouse gas emissions meet certain specified thresholds.

This Determination is made under subsection 10 (3) of the Act and provides methods, and criteria for methods, for the estimation and measurement of the following items arising from the operation of facilities:

(a) greenhouse gas emissions;

(b) the production of energy; and

(c) the consumption of energy.

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.

The scope of the Determination is given by the following categories of emission sources classified by the Intergovernmental Panel on Climate Change (IPCC) and as adopted by the UN Framework Convention on Climate Change.

The emission sources are:

- UNFCCC Category 1A: emissions from the **combustion of fuel** for energy (see chapter 2);
- UNFCCC Category 1B: **fugitive emissions** from the extraction, production, flaring, processing and distribution of fossil fuels (see chapter 3);
- UNFCCC Category 2: emissions from **industrial processes** where a mineral, chemical or metal product is formed using a chemical reaction that generates greenhouse gases as a by-product (see chapter 4); and
- UNFCCC Category 6: emissions from **waste** disposal - either in landfill, as management of wastewater or from waste incineration (see chapter 5).

The most important source is UNFCCC category 1A, which accounts for over 60 per cent of the emissions reported in the national greenhouse gas inventory.

The scope of this Determination does not include land based emissions covered by the IPCC categories ‘Agriculture’ and ‘Land Use, Land Use Change and Forestry’. Emissions from fuel combustion for land based industries are, nonetheless, covered by this Determination.

Section 1.4 Methods of 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.

This Determination provides 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.*

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 the Determination. For emissions from fuel combustion, for example, data on fuel consumption would be multiplied by a specific emission factor for that fuel to generate an emissions estimate. A similar approach has been used for over a decade in the voluntary reporting program *Greenhouse Challenge Plus* and before that, *Greenhouse Challenge*.

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 analysing 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 is already widely used in the electricity industry - in part for commercial reasons and in part because of the reporting processes under the *Generator Efficiency Standards* program.

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 Determination 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 Determination aims to minimise the reporting burden on corporations. As indicated above, there are many instances where higher 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 methods with the benefits of potentially improved emission estimates.

A framework for Method selection

The four Methods in the Determination 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 Climate Change for the preparation of the *National Greenhouse Accounts*. The use of methodologies from the *National Accounts* anchors Method 1 within the international guidelines adopted by the UN Framework Convention on Climate Change 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 Climate Change using the Australian Greenhouse Emissions Information System (AGEIS).

Although significantly updated, this Method is very similar in approach to that used by many corporations for over a decade to report emission estimates under the *Greenhouse Challenge Plus* program.

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.

Method 2: 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 existing technical guidelines 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: 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 equivalent documentary standards for sampling (of fuels or raw materials) 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 aims to directly monitor greenhouse emissions arising from an activity. This approach can provide a higher level of accuracy in certain circumstances, depending on the type of emission process, however, it is more data intensive than other approaches. Such 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.

Section 1.5 Energy

Methods for the estimation of the energy content of fuels produced and fuels consumed is addressed in Chapter 6. Data collected for the estimation of emissions from fuel combustion will serve a dual purpose as the data for the consumption of energy. Separate collections are required for the production of energy.

Section 1.6 Scope 2 emissions

This Determination principally deals 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 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.

Division 1.1.2 Definitions and Interpretations

Provides definitions for important terms used in the Determination.

Many of the estimation methods will be undertaken with reference to documentary standards developed by, inter alia, standards organisations. Section 1.9 indicates that these standards instruments or other writing must be in force at 1 July 2008 to be applicable. It is intended that the Determination will be reviewed at periodic intervals to consider development of new standards.

Part 1.2 General

Division 1.2.1 Measurements and standards

The objectives of the Determination are to provide methods to support estimates of emissions that meet the following criteria:

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

(b) comparability — emission estimates by a registered corporation in an industry sector must be, in principle, comparable with emission estimates produced by similar corporations in that industry sector and consistent with the emission estimates published by the Department of Climate Change in the *National Greenhouse Accounts*;

(c) accuracy — having regard to the availability of reasonable resources by a registered corporation and the requirements of this Determination, uncertainties in emission estimates are to be minimised and any estimates must be expected to be neither over nor under estimates of the true values;

(d) completeness — all identifiable emission sources within the energy, industrial process and waste sectors as identified by the *National Inventory Report, submitted by the Australian Government under the UN Framework Convention on Climate Change* are to be accounted for.

Section 1.14 Assessment of uncertainty

Estimates of the uncertainty of emission estimates must be provided for a corporation. Details on the parameters to be used for the estimation of uncertainty are given in Chapter 8.

Sections 1.15 and 1.16 Units of measurement and rounding

Standard units of measurement are prescribed for emissions - tonnes of CO_2-equivalent. Provision is also made for standard units of measurement for solid, gaseous and liquid fuels to be utilised in emission calculations and for reporting, unless otherwise provided for. For gaseous fuels, the standard unit of measurement is cubic metres, although allowance is made for measurement in gigajoules if invoices are provided in those units.

Division 1.2.2 Selection of Methods

This Division sets out the rules for a Reporter to change the Method of emissions estimation chosen. It is intended to strike a balance between the important objectives of maintaining consistency for a facility’s emission estimates over time and leaving open the opportunity for a Reporter to improve their emissions estimates by adopting a higher order Method at any time.

Consequently, for an emissions source, once a Method has been selected by a Reporter, this selection should be maintained throughout a minimum four year period unless a Method with a higher number is chosen. After four years, a Reporter may select a lower order method.

In the event of a temporary failure of the measuring equipment, a period of six weeks may elapse, not including down time for the calibration of measuring instruments, before this may considered to be a change in Method.

Part 1.3 – Method 4 – Direct measurement of emissions

Division 1.3.1 Preliminary

Section 1.20 Overview

Part 1.3 sets out Method 4 that provides for direct measuring of emissions of greenhouse gases. Such monitoring 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 standardized reporting for estimating greenhouse gas emissions.

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 licences 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/

The following Divisions, 1.3.2 and 1.3.3 sets out two versions of direct emissions monitoring described by this instrument. The two versions are Continuous Emissions Monitoring systems (CEM) and Periodic Emissions Monitoring systems (PEM).

Division 1.3.2 Operation of method 4 (CEM)

Section 1.21 provides the equation to be used to calculate emissions from direct emissions monitoring under CEM systems. The equation uses the data gathered from flow rate and gas analyser equipment to calculate mass emissions. This equation 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 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.

Sections 1.22 to 1.26 sets out specific requirements of the CEM system regarding location of sampling positions, measuring flow rates and gas composition and the frequency of measurement. These specific components of CEM make use of internationally recognised standards or methods. The organisations that have been cited include:

- Standards Australia (AS)
- International Organisation 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 1.

Division 1.3.3 Operation of method 4 (PEM)

Section 1.27 sets out the estimation of emissions using PEM systems. Whereas CEMS is designed to measure real-time hourly emissions estimates, 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.

Section 1.28 sets out a method for using PEM data to calculate emission factors for use in Method 2 by dividing the emissions estimated under section 1.27 by the amount of fuel combusted or raw material produced during the year.

Sections 1.29 to 1.33 set out specific requirements of the PEM system regarding location of sampling positions, measuring flow rates and gas composition and the frequency of measurement. These specific components of PEM make use of internationally recognised standards or methods. The organisations that have been cited include:

- Standards Australia (AS)
- International Organisation 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 1.

Division 1.3.4 Performance characteristics of equipment

Division 1.3.4 sets out appropriate standards for maintaining and evaluating the performance characteristics of CEM and PEM equipment. The requirements are set out in the standards listed in appendix 1 for direct measurement.

CHAPTER 2 FUEL COMBUSTION (UNFCCC CATEGORY 1.A)

Part 2.1 Preliminary

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

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. Fuels used as carbon reductants—for example, as in the production of steel—are addressed in Chapter 4.

This chapter provides methods for the estimation of emissions from fuel combustion. The chapter is divided into parts – Parts 2.2, 2.3 and 2.4 address the estimation of emissions from solid, gaseous and liquid fuels and Parts 2.5, 2.6 and 2.7 address a series of miscellaneous issues.

Part 2.2 Emissions released from the combustion of solid fuels

Division 2.2.1 Preliminary

Sections 2.2 and 2.3 specify that one of the four Methods must be used to estimate emissions of a particular gas for each source. This means that a Reporter may select a different Method to estimate the emissions of each gas – in particular, a Reporter may select Method 2, 3 or 4 for carbon dioxide while for methane and nitrous oxide, the Reporter must select Method 1 for methane and nitrous oxide as only one Method is available.

Section 2.3 (2) specifies that for incidental source streams, as defined in section 4.27 of the Regulations, Reporters may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

Section 2.3 (3) specifies that for carbon dioxide from the combustion of solid fuels the choice of Methods is limited to Methods 2, 3 and 4 for facilities where the main activity is electricity generation, ANZSIC class 2611. This limitation reflects current experience of generators that already estimate emissions with procedures from the *Generator Efficiency Standards* program on which Methods 2 and 3 are derived.

Division 2.2.2 Method 1 – Emissions of carbon dioxide, methane and nitrous oxide from solid fuels

Method 1 is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*. The approach is similar to that taken for the estimation of emissions from the Greenhouse Challenge Plus program. 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 Schedule 1 of the National Greenhouse and Energy Reporting Regulations 2008.

Energy content and emission factors required for the estimation of emissions from the combustion of solid fuels using this approach are given in Schedule 1 of the Determination. 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 is available, the Reporter may utilise Method 2, 3 or 4).

The emission factors for use in Method 1 have been estimated using the *Australian Greenhouse Emissions Information System (AGEIS)* operated by the Department of Climate Change. 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*.

Example

A facility consumes 20,000 tonnes of washed black 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 black coal. Emissions are estimated as follows:

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

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_2-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 black coal.**

EC_i is the energy content factor of the type of fuel measured in gigajoules per tonne according to source as mentioned in Schedule 1. **In this case it is 27 gigajoules per tonne for black coal.**

EF_{ijoxec} 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_2-e per gigajoule according to source as mentioned in Schedule 1. **In this case, for carbon dioxide, it is 88.2 kg CO_2-e per gigajoule for black coal. For methane, the emission factor is 0.03 kilograms per gigajoule and for nitrous oxide, 0.2 kilograms per gigajoule.**

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

Emissions of carbon dioxide from combustion of black coal:

= (20,000 x 27.0 x 88.2)/1,000

= 47,628 t CO_2-e

Emissions of methane from combustion of black coal:

= (20,000 x 27.0 x 0.03)/1,000

= 16 t CO_2-e

Emissions of nitrous oxide from combustion of black coal:

= (20,000 x 27.0 x 0.2)/1,000

= 108 t CO_2-e

Division 2.2.3 Method 2 – Emissions from solid fuels

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. The listing of applicable standards for the analysis of solid fuels is given in Schedule 2. 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 at 1 July 2008.

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 Schedule 2. These frequencies correspond to those specified in the *Technical Guidelines for the Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage.

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, the oxidation factors adopted reflect current practice for the electricity generation industry in their estimation of emissions under the *Generator Efficiency Standards* program. The default oxidation factor listed by the Intergovernmental Panel in Climate Change is provided for other consumers of solid fuels.

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).

Example

A facility consumes 100,000 tonnes of black 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:

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

where:

C_{ar} is the percentage of carbon in fuel type (***i***) as received for the facility. **In this case the percentage of carbon in black 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 x 0.98 x 3.664

= 2.69 kg of CO_2-e per kg of fuel

2. Estimate the carbon dioxide emission factor for fuel type (*i*) measured in kilograms of CO_2-e per kilogram of fuel as follows:

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

where:

$EF_{ico2ox,kg}$ is the carbon dioxide emission factor for fuel type (***i***) measured in kilograms of CO_2-e per kilogram of fuel.

EC_i is the energy content factor of fuel type (***i***) estimated by analysis of the fuel in accordance with the standard in the table in Part 1 of Schedule 1 or an equivalent standard. **In this case the energy content factor of black coal is estimated to be 28.5 GJ/t.**

= 2.69/28.5 x 1 000

= 94.5 kg of CO_2-e per gigajoule

3. Estimate emissions as follows:

$$\boxed{E_{ico_2} = \frac{Q_i \times EC_i \times EF_{ico_2oxec}}{1\,000}}$$

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_2-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 by analysis of the fuel in accordance with the standard indicated for that parameter in the table in Part 1 of Schedule 2 or an equivalent standard or from Schedule 1.

$EF_{ico2oxec}$ is the carbon dioxide emission factor for fuel type (***i***) measured in kilograms of CO_2-e per gigajoule.

= 100,000 x 28.5 x 94.5/1 000

= 269,304 tonnes of carbon dioxide emissions (CO_2-e).

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

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

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_2-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 the type of fuel measured in gigajoules per tonne according to source as mentioned in Schedule 1.

EF_{ijoxec} 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_2-e per gigajoule (Schedule 1).

Emissions of methane from combustion of black coal:

= (100,000 x 27.0 x 0.03)/1 000

= 81 t CO_2-e

Emissions of nitrous oxide from combustion of black coal:

= (100,000 x 27.0 x 0.2)/1 000

= 540 t CO_2-e

Division 2.2.4 Method 3 – Emissions of carbon dioxide from 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.

Division 2.2.5 Measurement of consumption of solid fuels

Fuel types identified in the Determination are as specified in the Regulation, Schedule 1. The fuel types listed principally reflect the lists of fuels currently reported to the Australian Bureau of Agricultural and Resource Economics (ABARE), which ABARE uses to prepare reports, *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.

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 (2.14);

(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 at the facility (2.15);

(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 (2.16);

(d) Criterion BBB - simplified measurement of consumption (2.17).

Measuring equipment calibrated to a measurement requirement mentioned in Section 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. These standards were also set out in the *Technical Guidelines for the Generator Efficiency Standards* program.

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.

Part 2.3 Emissions released from the combustion of gaseous fuels

Division 2.3.1 Preliminary

Sections 2.18 and 2.19 specify that one of the four Methods must be used to estimate emissions of a particular gas for each source. This means that a Reporter may select a different Method to estimate emissions of each gas – for example, a Reporter may select Method 2, 3 or 4 for carbon dioxide while the Reporter may select Method 1 for methane and nitrous oxide.

Section 2.19 (2) specifies that for incidental source streams, as defined in National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, industry may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

Section 2.19 (3) specifies that for carbon dioxide from gaseous fuels the choice of Methods is limited to Methods 2, 3 and 4 for facilities where the main activity is electricity generation, ANZSIC class 2611. This limitation reflects current experience of generators that already estimate emissions with procedures from the *Generator Efficiency Standards* program on which Methods 2 and 3 are derived.

Division 2.3.2 Method 1 – Emissions of carbon dioxide, methane and nitrous oxide

As for solid fuels, Method 1 is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*. The approach is similar to that used for the Greenhouse Challenge Plus. 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 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 in Schedule 1 of the Determination. These factors are intended to be default factors – to be used in the absence of better information.

The factors listed in Schedule 1 and have been estimated using the *Australian Greenhouse Emissions Information System (AGEIS)* operated by the Department of Climate Change. Consequently, they are determined simultaneously with the production of *Australia's National Greenhouse Accounts* ensuring that Reporter inventories are consistent with those *national accounts*.

Division 2.3.3 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.

Method 2 is based on 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.

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 in force at 1 July 2008.

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. These frequencies correspond to those specified in the *Technical Guidelines for the Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage. With the results of the analysis, emissions may then be estimated in accordance the equations specified in Method 2.

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 in section 2.26 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.

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 Schedule 1.

Division 2.3.6 Measurement of quantities of gaseous fuels

Fuel types identified in the Determination are as specified in the Regulation, Schedule 1. The fuel types listed mainly reflect the lists of fuels currently reported to the Australian Bureau of Agricultural and Resource Economics (ABARE), which ABARE uses to prepare reports to the International Energy Agency. Quantities of fuels consumed should exclude those quantities consumed for international transport purposes to reflect international reporting requirements for the national inventory.

Division 2.3.6 specifies the criteria for the estimation of the amounts of gaseous fuels combusted from the operation of a facility during a year. 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.

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.

Part 2.4 Emissions released from the combustion of liquid fuels

Division 2.4.1 Preliminary

Sections 2.39 and 2.40 specify that one of the four Methods must be used to estimate emissions of a particular gas for each source. This means that a Reporter may select a different Method to estimate emissions of each gas – for example, a Reporter may select Method 2, 3 or 4 for carbon dioxide while the Reporter may select Method 1 for methane and nitrous oxide.

Section 2.40 (2) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

Division 2.4.2 Method 1 – Emissions of carbon dioxide, methane and nitrous oxide

As for solid and gaseous fuels, Method 1 is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*. The approach is similar to that taken for the estimation of emissions under the Greenhouse Challenge Plus program. 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).

Energy content and emission factors required for the estimation of emissions using this approach are given in Schedule 1. These factors are intended to be default factors – to be used in the absence of better information.

The factors listed in Schedule 1 and have been estimated using the *Australian Greenhouse Emissions Information System (AGEIS)* operated by the Department of Climate Change. 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.

Example

A company consumes 35 000 kL (kiolitres) 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 the diesel consumed for transport by post 2004 vehicles. Emissions are estimated as follows:

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

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_2-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 the fuel type (***i)*** measured as energy content in gigajoules per tonne according to source as mentioned in:

(a) for stationary energy purposes — column 4 of the table in Part 3 of Schedule 1. **In this case being 38.6 GJ/kL.**

(b) for post-2004 vehicles — column 4 of the table in Division 4.2 of Part 4 of Schedule 1). **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_2- e per gigajoule of the fuel type (***i***) according to source as mentioned in:

(a) for stationary energy purposes — column 4 of the table in Part 3 of Schedule 1; and

(b) for post-2004 vehicles — column 4 of the table in Division 4.2 of Part 4 of Schedule 1.

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 69.2)/1 000

= 26 711 t CO_2-e

Emissions of methane

= (10 000 x 38.6 x 0.1)/1 000

= 39 t CO_2-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 (Method 2):

Emissions of carbon dioxide

= (25 000 x 38.6 x 69.2)/1 000

= 66 778 t CO_2-e

Emissions of methane

= (25 000 x 38.6 x 0.01)/1 000

= 10 t CO_2-e

Emissions of nitrous oxide

$= (25\ 000 \times 38.6 \times 0.6)/1\ 000$

$= 579$ t CO_2-e

Division 2.4.3 Method 2 – Emissions of carbon dioxide from the combustion of liquid fuels

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 Schedule 1 of the National Greenhouse and Energy Reporting Regulations 2008.

Method 2 is based on 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.

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 at 1 July 2008. 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. These frequencies correspond to those specified in the *Technical Guidelines for the Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage.

Division 2.4.4 Method 3 – Emissions of carbon dioxide released from the combustion of liquid fuels

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.

Division 2.4.5 Method 2 - Emissions of methane and nitrous oxide from the combustion of liquid fuels

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. 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.

Division 2.4.6 Measurement of quantity of liquid fuels

Fuel types identified in the Determination are as specified in the Regulation, Schedule 1. The fuel types listed reflect the lists of fuels currently reported to the Australian Bureau of Agricultural and Resource Economics (ABARE), which ABARE uses to prepare reports to the International Energy Agency. For liquid products subject to excise, it is intended that the fuel types listed in Schedule 1 of the National Greenhouse and Energy Reporting Regulations 2008, should correspond to classifications set out in the Schedule of the *Excise Tariff Act 1921.* No category is provided for blended fuels, however. Blended fuels must be separated into estimates of quantities of constituent fuels. Blended fossil and biogenic carbon fuels should be separated in accordance with Part 2.6.

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 must be reported, however.

The quantities of fuels consumed should exclude those quantities consumed for international transport purposes to ensure the reporting system aligns with the reporting requirements of the IPCC reporting guidelines for national inventories. It is intended that this may be achieved by excluding international bunker fuels as defined in the 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 2.4.6 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.

Part 2.5 Emissions released from fuel use by certain industries

The IPCC classifies emissions from fuel use according to the purpose that the fuel was used. In particular it differentiates between fuels combusted for energy (heat and power) and fuels consumed either as feedstock or as a reductant. Emissions from the former are addressed in chapter 2. Emissions from the latter are generally addressed in chapter 4 - Industrial process emissions. This Part provides guidance on the allocation of fuel consumption between the two categories in certain instances.

Division 2.5.1 sets out that Reporters that fall under petroleum refining UNFCCC Category 1.A.1.b should estimate emissions from fuel combusted for energy and fuel consumed as a feedstock under this chapter. Emissions from the production of hydrogen should be estimated in accordance with the method provided in the American Petroleum Institute’s *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* 2004, sections 5 and 6.1.2 and reported under this UNFCCC category. Methods for the estimation of emissions from fugitive sources of emissions, including the burning of catalyst coke for non-energy purposes, are addressed in chapter 3.

Division 2.5.2 sets out that the treatment of UNFCCC Category 1.A.1.c — solid fuel transformation (coke ovens) - is provided in chapter 4 under iron and steel production. This is because an integrated steelworks, which produces both coke and uses coke in steel production, consumes fuel both as an energy source and as a reductant and can therefore be treated as one estimation process within chapter 4 (Part 4.3). Emissions from the integrated steelworks are estimated using a single carbon mass balance approach for the whole facility including both the coke ovens and the steelworks.

Division 2.5.3 sets out the Methods for estimation of emissions from fuel both combusted for energy and consumed as a feedstock for the petrochemical industry. Some petrochemical processes, such as the production of certain plastics, act to store carbon in products - for this storage to be taken into account in the estimation of emissions the fuel consumed in the production of these products needs to be separately identified. As is the case with the *EU Guidelines for the monitoring and reporting of greenhouse gas emissions,* a carbon mass balance approach is provided in order to estimate emissions from this source.

Part 2.6 Blended fuels

This Part sets out determination of the amounts of each fuel type (i) that is in a blended fuel if that blended fuel is a solid or liquid fuel. Because of the variation in the emission factors that apply to different fuels, it is necessary to separate out the constituent amounts of fuel within a blend before estimation of emissions.

Part 2.7 Estimation of energy for certain purposes

Section 2.68 Amount of fuel consumed without combustion

The National Greenhouse and Energy Reporting Regulations 2008, state that corporations should report the amounts of types of energy (ie fuels) that have been consumed without combustion. Separate reporting of these fuels consumed is important as they do not lead to greenhouse emissions, as they are not combusted. Examples of the use of fuels without combustion include:

1.1. fuel used in a non-energy manner – for example, fuels used directly as solvents or flocculants, waxes, bitumen;

1.2. fuel used as an ingredient in the manufacture of short-life products such as paints, cleaning agents and explosives manufactured for sale;

1.3. fuel 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 item 10.28 of the Schedule to the *Excise Tariff Act 1921*); and

1.4. fuel blended with other products and then packaged for non-internal combustion engine use.

These amounts need to be reported only if certain thresholds are exceeded. Section 2.68 sets out the reporting thresholds as:

(i) for solid fuel —20 tonnes; or

(ii) for gaseous fuel —13000 cubic metres; or

(iii) for liquid fuel —15 kilolitres.

This data will be used for statistical purposes and for compliance with Australia's reporting requirements under the International Energy Agency.

Section 2.69 Apportionment of fuel consumed as carbon reductant or feedstock and energy

The IPCC classifies emissions from fuel use according to the purpose that the fuel was used. In particular it differentiates between fuels combusted for energy (heat and power) and fuels consumed either as feedstock or as a reductant. Emissions from the former are addressed in chapter 2. Emissions from the latter are generally addressed in chapter 4 - *Industrial process emissions*. This Division provides guidance on the allocation of fuel consumption between the two categories in certain instances.

Section 2.69 determines how the Reporter should allocate quantities of fuels between the amount of fuel consumed as a reductant/feedstock and the amount combusted as energy in cases where 1) a fuel type is consumed as both a reductant/feedstock and combusted for energy - such as in the case of an integrated steelworks - and 2) where the equipment used to measure the amount of the fuel is also not calibrated to a measurement requirement: (or, in other words, where quantities of fuels consumed as reductants/feedstocks directly is not monitored to the same accuracy as would occur, for example with fuels purchased or sold).

In these circumstances it is intended that the total consumption of an individual fuel type for the facility should be estimated first in accordance with measurement criteria set out in Divisions 2.2.5, 2.3.6 and 2.4.6 and used for the estimation of the facility's emissions.

The estimated total fuel consumed should then be allocated between the use of fuel as a reductant/feedstock and the use of fuel combusted for energy.

It is intended that the total fuel consumption should be apportioned completely to the industrial process use (that is, the fuel is treated as a reductant/feedstock) unless the Reporter has information to base an alternative apportionment. If the Reporter has information that enables apportionment, for example, such as separate plants within a facility (for example, coke ovens and a blast furnace), then the fuel consumed as a reductant/feedstock should be estimated first, and then the residual should be allocated to the combustion for energy.

The quantities derived from the apportionment will only be used for statistical purposes and do not affect the total emissions estimated for the facility.

Section 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.

Section 2.70 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.

EXAMPLE: Co-generation

An example calculation to illustrate the application of the efficiency method can be found in the *Allocation of Emissions from a Combined Heat and Power (CHP) Plant Guide to calculation worksheets (September 2006) v1.0*.

CHAPTER 3 Fugitive emissions from fuels (UNFCCC Category 1.B)

Part 3.2 Coal Mining (UNFCCC Category 1.B.1)

Division 3.2.1 Preliminary

Section 3.2 specifies that this part applies to UNFCCC category 1.B.1 – fugitive emissions from coal mining. The major sources of emissions from this category include emissions from underground mining activities, open cut mining activities and emissions from decommissioned mines.

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.

Division 3.2.2 Underground mines

Sections 3.3 and 3.4 specify the methods available for estimating emissions from underground mining activities, including emissions associated with extraction of coal, flaring of coal mine waste gas and post-mining activities. Gases include methane, carbon dioxide and nitrous oxide.

Section 3.4 (7) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

Section 3.4 (8) specifies that if coal mine waste gas is captured for combustion during the year, then method 1 for coal extraction cannot be used - this ensures consistent estimation methods are used for the estimation of both methane generation from the mine and from methane capture. This approach ensures that where a more accurate estimate of emissions generated by the mine is available – ie based on the quantity of emissions captured – that this better data is used rather than the emissions data generated using Method 1.

Section 3.5 sets out Method 1 for underground mining operations associated with the extraction of coal. 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 a mine type (gassy or non gassy underground mine) emission factor.

Section 3.6 to 3.13 sets out Method 4 for estimating emissions associated with underground mining operations. Reporters may also directly measure emissions using periodic emissions measurement (PEMS) 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.

Section 3.14 to 3.16 sets out Methods for estimating emissions from 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 each gas type. The quantity of gas flared is estimated in accordance with Division 2.3.6. The energy content and emission factors are obtained from Schedule 1 of the Determination.

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. 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. It is intended that all carbon dioxide and non-combusted methane should be estimated as fugitive emissions.

Section 3.17 sets out Method 1 for estimating emissions from post-mining activities associated with gassy underground mines. 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.

Division 3.2.3 Open cut mines

Sections 3.18 and 3.19 specify the Methods available for estimating emissions from open cut mining activities, including emissions associated with extraction of coal, flaring of coal mine waste gas and venting.

Section 3.19 (7) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

Section 3.20 sets out Method 1 for open cut mining operations associated with the extraction of coal. The method 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. The emission factors are as used in the National Inventory Report and as reviewed by international experts.

Example

A facility constituted by an open cut coal mine in NSW extracts 2,554,000 tonnes of run-of-mine 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:

$$\boxed{E_j = Q \times EF_j}$$

where:

E_j is the emissions of methane (j) released from the extraction of coal from the mine during the year, measured in CO2-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 0.045 tonnes CO_2-e per tonne of raw coal extracted.**

Therefore, the estimate of methane emissions in CO_2-e tonnes:

$$E_j = Q \times EF_j$$

$$= (2,554,000 \text{ x } 0.045)$$

Total emissions of methane = 114,930 t CO_2-e

Section 3.21 to 3.26 sets out Methods 2 and 3 for estimating emissions from open cut mining. Gases include methane and carbon dioxide. The method involves sampling coal and non-coal strata layers for the analysis of gas content to determine an estimated total stock of gas. Total emissions for an extraction area can then be estimated from the estimated total stock of gas contained within the strata layers. The general framework for this method is based on 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.

More specific components of the methods such as the sampling of coal seams and surrounding rock strata and measuring the gas contents of the coal and non-coal strata must be done in accordance with Australian standards or equivalent. Additional relevant standards for the estimation and reporting of gas bearing strata (in particular layers of coal) include:

- The Australian code for reporting of exploration results, mineral resources and ore reserves. The Joint Ore Reserves Committee (JORC) Code, 2004 edition
- Australian Guidelines for Estimating and Reporting of Inventory Coal, Coal Resources and Coal Reserves. Prepared by the Coalfields Geology Council of NSW and the Queensland Mining Council, 2003.

These industry standards can be obtained from: http://www.jorc.org.

The stock of gas released at the time of extraction will also reflect past quantities of gas captured for combustion, flared or transferred off site. It is intended that these emissions should be estimated and reported at the time they occur. However, as emissions from the operating mine are to be determined using a stock of gas approach, these estimated emissions will be summed over time and deducted from the available stock of gas to be released at the time of mining.

Other specific references are detailed within the Determination.

Section 3.27 to 3.29 sets out Methods for estimating emissions from 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 each gas type. The quantity of gas flared is estimated in accordance with Division 2.3.6. The energy content and emission factors are obtained from schedule 1 of the Determination.

Method 2 requires representative and unbiased samples of coal mine waste gas consumed and analysis of the coal mine waste gas to determine composition must be done in accordance with Australian or equivalent international standards and as set out under Division 2.3.3. 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 as set out under Division 2.3.4. It is intended that all carbon dioxide and non-combusted methane should be estimated as fugitive emissions.

Division 3.2.4 Decommissioned underground mines

Sections 3.30 and 3.31 specify the methods available for estimating emissions from decommissioned underground mines including, flaring of coal mine waste gas and venting. This Division only applies if an underground mine has been closed for a continuous period of less than 20 years.

Section 3.31 (5) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

Section 3.31 (6) specifies that if coal mine waste gas is captured for combustion during the year, then method 1 for decommissioned mines cannot be used. This approach ensures that where a more accurate estimate of emissions generated by the mine is available – ie based on the quantity of emissions captured – that this better data is substituted for the Method 1-generated emissions data.

Section 3.32 to 3.36 specifies Method 1 for decommissioned mines. The Method is derived from the *National Greenhouse Account* national methodology as published in the *National Inventory Report*.

Emissions from decommissioned mines involves the decline of emissions following mine closure and is calculated using emission decay curves for dry, gassy and non-gassy mines adjusted on a mine-by-mine basis, according to the flooding characteristics of each mine. The equation (in section 3.33) for emission decay curves is derived from the *National Inventory Report*.

Sections 3.34 to 3.36 describe the flooding characteristics of a decommissioned mine. The flooding rate can be estimated using the default calculation set out in this determination or can be estimated using available standards and / or industry practice.

Section 3.37 sets out Method 4 which is the same as for section 3.6.

Section 3.38 to 3.40 sets out Methods for estimating emissions from 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 each gas type. The quantity of gas flared is estimated in accordance with Division 2.3.6. The energy content and emission factors are obtained from schedule 1 of the Determination.

Method 2 requires representative and unbiased samples of coal mine waste gas consumed and analysis of the coal mine waste gas in accordance with Australian or equivalent international standards. 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. It is intended that all carbon dioxide and non-combusted methane should be estimated as fugitive emissions.

Part 3.3 Oil and Natural Gas: fugitive emissions (UNFCCC Category 1.B.2)

Division 3.3.1 Preliminary

Division 3.41 sets out the separate UNFCCC sub-categories which include emissions from exploration, production, transport, storage, processing and refining of oil and natural gas.

Other sources of emissions arising from the production processes 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 3.3.2 Oil and gas exploration

Method 1 for oil exploration (UNFCCC Category 1.B.2.a.i) and gas exploration (UNFCCC Category 1.B.2.b.i) is derived from the *National Greenhouse Accounts*.

These sections set out methods 1, 2 and 3 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 and the American Petroleum Institute’s *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* 2004.

Division 3.3.3 Crude oil production

Emissions arise for this category from fugitive sources (for example gas leaks), 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.

Method 1 for crude oil production (UNFCCC Category 1.B.2.a.ii) for fugitive emissions is derived from the *National Greenhouse Accounts* and is set out in 3.49.

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 Gas Industry* 2004, sections 5 and 6.1.2.

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 and the API Compendium.

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 *(Division 3.3.3)* 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)

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

where:

E_{ij} is the emissions measured in CO_2 e tonnes of methane (j),, released from the crude oil production during the year.

Σ_k is the emissions of methane (j) measured in tonnes of CO_2-e and estimated by summing up the emissions released from all of the equipment of type (k) specified, where 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. **In this case it is the crude oil throughput for the floating tank – 685,000 tonnes**.

EF_{ijk} is the emission factor for methane (j) measured in tonnes of CO_2-e per tonne of crude oil that passes through each equipment of type (k) specified in column 2 of the table in subsection (2) during the year, if the equipment is used in the crude oil production. **In this case it is the emission factor for the floating tank – 3.2 x 10^{-6} CO_2-e/tonnes fuel throughput.**

Q_i is the total quantity of crude oil (i) measured in tonnes that passes through the crude oil production. **In this case it is the crude oil production throughput – 710,400 tonnes**.

$EF_{(l)\ ij}$ is 1.2 x 10^{-3}, which is the emission factor for methane (j) from general leaks in the crude oil production, measured in CO_2 e tonnes per tonne of crude oil that passes through the crude oil production.

Therefore, the estimate of methane emissions in CO_2-e tonnes :

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

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

Total emissions of methane = 855 t CO_2-e

Part A: Crude oil production (non flared component)

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

where:

E_{ij} is the emissions measured in CO_2-e tonnes of gas type (j) released 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 the crude oil production during the year. **In this case the quantity of crude oil flared is 400 tonnes**.

EF_{ij} is the emission factor for gas type (j) measured in tonnes of CO_2-e emissions per tonne of the fuel type (i) flared. The emission factors are obtained from Method 1 *(Division 3.3.3).*

Therefore, the estimate of greenhouse gas emissions (from carbon dioxide, methane and nitrous oxide (j)) in CO_2-e tonnes:

For carbon dioxide

=400 x 3.2

Total emissions of carbon dioxide = 1280 t CO_2-e

For methane

=400 x 0.007

Total emissions of methane = 3 t CO_2-e

For nitrous oxide

=400 x 0.07

Total emissions of nitrous oxide = 28 t CO_2-e

Division 3.3.4 Crude oil transport

Emissions arise for this category from fugitive sources (for example gas leaks).

Method 1 for crude oil transport (UNFCCC Category 1.B.2.a.iii) for fugitive emissions is derived from the *National Greenhouse Accounts*.

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 Gas Industry* 2004 sections 5 and 6.1.2.

Division 3.3.5 Crude oil refining

Emissions arise for this category from fugitive sources (for example gas leaks), flaring and from 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.

Sub-division 3.3.5.1 Fugitive emissions from crude oil refining and from storage tanks for crude oil

Section 3.63 sets out Method 1 for fugitive emissions from crude oil refining (UNFCCC Category 1.B.2.a.iv). This method is derived from the methods used for the *National Greenhouse Accounts*.

Section 3.64 sets out Method 2 for fugitive emissions from crude oil refining which 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 Gas Industry* 2004 sections 5 and 6.1.2.

Sub-division 3.3.5.2 Fugitive emissions from deliberate releases from process vents, system upsets and accidents

Section 3.65 sets out Method 1 for the estimation of emissions from the burning of catalyst coke for non-energy purposes, which is derived from the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* 2004 sections 5.2.

It is intended that that there should 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.

Section 3.66 sets out that these emissions may also be estimated using Method 4 as described in Chapter 1. In this case, an additional option is described taken from the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* 2004 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.

Sub-division 3.3.5.3 Fugitive emissions released from gas flared from the oil refinery

Sections 3.67-3.69 set out Methods 1, 2 and 3 for the flaring of fuels. 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.

Division 3.3.6 Natural gas production and processing (other than emissions that are vented and flared)

Emissions arise for this category from fugitive sources (for example gas leaks).

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.

Section 3.72 sets out Method 1 for fugitive emissions from natural gas production and processing (UNFCCC Category 1.B.2.b.ii). This method is derived from the methods used for the *National Greenhouse Accounts*.

Section 3.73 sets out Method 2 for fugitive emissions from natural gas production and processing which 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 Gas Industry* 2004 sections 5 and 6.1.2.

Division 3.3.7 Natural gas transmission

Emissions arise for this category from fugitive sources (for example gas leaks).

Other sources of emissions arising from the natural gas transmission, 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.

Section 3.76 sets out Method 1 for fugitive emissions from natural gas transmission (UNFCCC Category 1.B.2.b.iii). This method is derived from the methods used for the *National Greenhouse Accounts*.

Section 3.77 sets out Method 2 for fugitive emissions from natural gas transmission which 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 Gas Industry* 2004 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.

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 *(Division 3.3.7)* 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_2 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_2-e tonnes.

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

EF_{ij} is the emission factor for gas type (j) being 0.02 for carbon dioxide and 8.7 for methane measured in tonnes of CO_2 e emissions per kilometre of pipeline (i).

Therefore, to estimate greenhouse gas emissions (from carbon dioxide and methane) in CO_2-e tonnes:

For carbon dioxide

=3600 x 0.02

Total emissions of carbon dioxide = 72 t CO_2-e

For methane

=3600 x 8.7

Total emissions of methane = 31,320 t CO_2-e

Division 3.3.8 Natural gas distribution

Emissions arise for this category from fugitive sources (for example gas leaks).

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.

Section 3.80 sets out Method 1 for fugitive emissions from natural gas distribution (UNFCCC Category 1.B.2.b.iv). This method is derived from the methods used for the *National Greenhouse Accounts*.

Section 3.81 sets out Method 2 for fugitive emissions from natural gas distribution which 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 Gas Industry* 2004 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.

Division 3.3.9 Natural gas production and processing (emissions that are vented or flared)

Sub-division 3.3.9.1 Fugitive emissions that result from deliberate releases from process vents, system upsets and accidents

Emissions arise for this category from vented emission sources.

Other sources of emissions arising from the production processes listed above, 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.

Section 3.84 sets out Method 1 for vented emissions from natural gas production and processing (UNFCCC Category 1.B.2.b.iv). This method is intended to be as specified in the American Petroleum Institute's *Compendium of Greenhouse Gas Emissions Estimation Methodologies for the Oil and Gas Industry* 2004 sections 5 and 6.1.2.

Section 3.83 (2) sets out that vented emissions may also be estimated in accordance with Method 4, as set out in chapter 1.

Sub-division 3.3.9.2 Flared emissions

Sections 3.85-3.87 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 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. Method 2 for methane emissions should be estimated in accordance with the guidance set out in the American Petroleum Institute Compendium.

CHAPTER 4 INDUSTRIAL PROCESS EMISSIONS (UNFCCC CATEGORY 2)

Industrial process emissions are an important source of emissions in Australia and are generated from a wide variety of activities. The major groups of activities generating emissions include:

1. mineral products—generally from the consumption of carbonate materials (such as limestone);

2. chemical products—generated mainly by the petrochemical industries;

3. metal products—generally from fossil fuel-derived carbon materials such as coke used as reductants (that is, the use of these fuels for non-energy purposes);

4. synthetic gas emissions—the release of halocarbons, perfluorocarbons and sulphur hexafluoride either as fugitive emissions or leakages from their use.

The categories of industries addressed in this chapter include Mineral Products (UNFCCC Category 2.A), Chemical Industry (UNFCCC Category 2.B) and Metal Products (UNFCCC Category 2.C). The chapter also includes emissions from the consumption of halocarbons and sulphur hexafluoride (UNFCCC Category 2.F).

Other sources of emissions arising in the course of the production of products from the industries mentioned in this chapter, 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.

Part 4.2 Industrial Processes - Mineral Products

This Part applies to any industry that generates emissions of carbon dioxide through the calcining (consumption through heat) of carbonates such as calcium carbonate (limestone) or magnesium carbonate. The consumption of carbonates other than through calcining (for example, as gravel) are not covered by the scope of this Determination.

Division 4.2.1 Cement clinker production

Section 4.4 sets out Method 1 for emissions of carbon dioxide released from the production of cement clinker (UNFCCC Category 2.A.1). This Method is derived from the methodology used for the *National Greenhouse Accounts*.

Sections 4.5 to 4.7 set out Method 2 for emissions of carbon dioxide released from the production of cement clinker. Method 2 requires sampling and analysis of the clinker and product to estimate the composition of the contents of the clinker and, from an understanding of the chemical reactions involved, the derivation of more accurate estimates of emissions of carbon dioxide from the production process.

Sections 4.8 to 4.10 set out Method 3. 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 raw material's pure carbonate content.

Section 4.3(2) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

Division 4.2.2 Lime production

Section 4.13 sets out Method 1 for emissions of carbon dioxide released from the production of lime (UNFCCC Category 2.A.2). This Method is derived from the methodology used for the *National Greenhouse Accounts*.

Sections 4.14 to 4.16 set out Method 2 for emissions of carbon dioxide released from the production of lime. Method 2 requires sampling and analysis of the lime product to estimate the composition of the contents of the lime and, from an understanding of the chemical reactions involved, the derivation of more accurate estimates of emissions of carbon dioxide from the production process.

Sections 4.17 to 4.19 set out Method 3. 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.

Section 4.13 (2) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

Division 4.2.3 Other uses of carbonates

The calcining of carbonates generates carbon dioxide emissions regardless of the industry. Apart from the production of cement clinker and lime, addressed in Divisions 4.2.1 and 4.2.2, industries that may be likely to calcine carbonates include the following:

- metallurgy
- glass manufacture, including fibreglass and mineral wools

- magnesia production
- agriculture
- construction
- environment pollution control.

Section 4.21 sets out that there is no method 2 for these sources (because under this Division, unlike for Divisions 4.2.1 and 4.2.2, there is no equivalent to the estimation of emissions from the analysis of the products obtained from calcining).

Section 4.22 sets out Method 1 for emissions of carbon dioxide released from the calcining of carbonates other than for cement or lime production (UNFCCC Category 2.A.3). This Method is derived from the methodology used for the *National Greenhouse Accounts*.

Sections 4.23 to 4.25 set out Method 3 for emissions of carbon dioxide released from the calcining of carbonates. 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.

Section 4.23 (2) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

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. Industries that may be likely to consume soda ash include the industries listed in Note Examples of uses of soda ash in production processes include the following:

- glass production
- soap and detergent production
- flue gas desulphurisation
- pulp and paper production..

Section 4.29 sets out Method 1 for emissions of carbon dioxide released from the consumption of soda ash (UNFCCC Category 2.A.4). This Method is derived from the methodology used for the *National Greenhouse Accounts*. As Method 1 relies on the assumption that the soda ash consumed is pure, there is no Method 2 or 3 for this category.

Section 4.30 sets out that there are four Methods available for the production of soda ash. Emissions arise from the consumption of fuels, as is the case for Chapter 2. Consequently, the methods are effectively the same as those set out in Chapter 2. Method 1 is set out in Section 4.31 and is based on methodology used for the *National Greenhouse Accounts.* Methods 2, 3 and 4 are the same as Methods 2, 3 and 4 set out in Chapter 2 for solid, gaseous and liquid fuels.

Section 4.28 (2) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

Division 4.2.5 Measurement of quantity of carbonates consumed and products derived from carbonates

Estimation of quantities of carbonate material consumed or products produced from carbonates are to be estimated in accordance with the same criteria as has been set out for the consumption of fuels (Divisions 2.2.5, 2.3.6 and 2.4.6).

Part 4.3 Industrial processes – chemical industry

This Part principally 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.

It is intended that the estimation of 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, are not described in this chapter and must be estimated using the Methods described in other chapters.

Division 4.3.1 Ammonia production

Section 4.41 sets out that all four methods are available for this source.

Section 4.42 sets out Method 1 for emissions of carbon dioxide released from the use of fuels as feedstocks in the production of ammonia (UNFCCC Category 2.B.1). This Method is derived from the methodology used for the *National Greenhouse Accounts*.

Section 4.43 and 4.44 set out methods 2 and 3. As for combustion of fuels, representative and unbiased samples of fuels consumed must be obtained for analysis for Method 2. 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 for gaseous fuels is given in Section 2.24. Examples of equivalent standards include those produced by AS, NZ, ASTM, ISO and CEN standards organisations. The standards must be in force at 1 July 2008.

Minimum frequencies of analysis for gaseous fuels are also provided for in section 2.24. These frequencies correspond to those specified in the Technical Guidelines for the *Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage.

As for combustion of fuels, 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, for gaseous fuels, in section 2.26 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.

Section 4.41(2) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.12: namely that the estimates are transparent, comparable, accurate and complete.

Division 4.3.2 Nitric acid production

Section 4.46 sets out that 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 (Section 4.46 (3)).

Section 4.47 sets out Method 1 for emissions of carbon dioxide released from the production of nitric acid (UNFCCC Category 2.B.2). This Method 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.

Section 4.48 sets out that for Method 2 facility-specific emission factors may be obtained by periodic emissions monitoring undertaken in accordance with the provisions of Chapter 1 (and, in particular, section 1.28). These emission factors would then be substituted into the equation specified in 4.47 (1) to estimate emissions.

Section 4.46 (2) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

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:

$\boldsymbol{E_{ijk}}$ is the emissions of nitrous oxide released during the year from the production of nitric acid at the plant type (k) measured in CO_2 e tonnes.

$\boldsymbol{EF_{ijk}}$ is the emission factor of nitrous oxide for each tonne of nitric acid produced during the year from plant type (k). **In this case the emission factor is 2.79 tonnes CO_2-e per tonne of nitric acid production for a high pressure plant.**

$\boldsymbol{A_{ik}}$ 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_2-e tonnes :

$$=45{,}000 \text{ x } 2.79$$

Total emissions of nitrous oxide = 125,550 t CO_2-e

Division 4.3.3 Adipic acid production

Section 4.50 sets out Method 1 for emissions of carbon dioxide released from the production of adipic acid (UNFCCC Category 2.B.3). The method to be used 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.

Division 4.3.4 Carbide production

Section 4.52 sets out Method 1 for emissions of carbon dioxide released from the production of carbide (UNFCCC Category 2.B.4). The method to be used is described in *IPCC 2006 Guidelines for National Greenhouse Gas Inventories Volume 3, Part 1.* Currently, there is no carbide acid production recorded in Australia.

Division 4.3.5 Titanium dioxide production

Section 4.54 sets out that all four Methods are available for this source.

Section 4.55 sets out Method 1 for emissions of carbon dioxide released from the use of fuels as carbon reductants in the production of titanium dioxide (UNFCCC Category 2.B.5). This Method is derived from the methodology used for the *National Greenhouse Accounts*.

Section 4.56 and 4.57 set out Methods 2 and 3. As for the combustion of fuels, representative and unbiased samples of fuels consumed must be obtained for analysis for Method 2. 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 for solid fuels is given in Schedule 2. Examples of equivalent standards include those produced by AS, NZ, ASTM, ISO and CEN standards organisations. The standards must be in force at 1 July 2008.

Minimum frequencies of analysis for solid fuels are also provided for in Schedule 2. These frequencies correspond to those specified in the Technical Guidelines for the *Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage.

As for combustion of fuels, 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, for solid fuels, 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 and other factors should be conducted as for Method 2. Emissions may then be estimated in accordance with Method 2.

Section 4.54(2) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

Division 4.3.6 Synthetic Rutile production

Section 4.59 sets out that all four Methods are available for this source.

Section 4.60 sets out Method 1 for emissions of carbon dioxide released from the use of fuels as carbon reductants in the production of synthetic rutile (UNFCCC Category 2.B.5). This Method is derived from the methodology used for the *National Greenhouse Accounts*.

Section 4.61 and 4.62 set out Methods 2 and 3. As for combustion of fuels, representative and unbiased samples of fuels consumed must be obtained for analysis for Method 2. 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 for solid fuels is given in Schedule 2. Examples of equivalent standards include those produced by AS, NZ, ASTM, ISO and CEN standards organisations. The standards must be in force at 1 July 2008.

Minimum frequencies of analysis for solid fuels are also provided for in Schedule 2. These frequencies correspond to those specified in the Technical Guidelines for the *Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage.

As for combustion of fuels, 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, for solid fuels, 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 and other factors should be conducted as for Method 2. Emissions may then be estimated in accordance with Method 2.

Section 4.59 (2) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

Example

A synthetic rutile production plant consumes 15,000 tonnes of black coal used as a reductant during the year. The Reporter elects to use Method 1 *(Division 4.3.6)* to calculate carbon dioxide emissions. Emissions are estimated as follows:

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

where:

E_{ij} is the emissions of carbon dioxide released as a result of the consumption of a carbon reductant in the production of synthetic rutile during the year measured in CO_2-e tonnes.

Q_i is the quantity of each fuel type (i) consumed as a carbon reductant in the production of synthetic rutile during the year measured in the appropriate unit. **In this case 15,000 tonnes of black coal was used as a reductant.**

EC_i is the energy content factor of the fuel type (***i***), used in the production of synthetic rutile during the year, measured as energy content in gigajoules per the appropriate unit. **In this case, energy content for black coal is 27GJ/t, sourced from Part 1 of Schedule 1.**

EF_{ij} is the carbon dioxide emission factor for the fuel type (***i***) used in the production of synthetic rutile during the year, including effects of oxidation, measured in kilograms for each gigajoule. **In this case, the CO_2 emission factor for black coal is 88.2 kg CO2-e/GJ, sourced from Part 1 of Schedule 1.**

Therefore, to calculate emissions of carbon dioxide in CO_2-e tonnes :

For carbon dioxide

=(15000 x 27 x 88.2)/1000

Total emissions of carbon dioxide = 35,721 t CO_2-e

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.

It is intended that the estimation of 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, are not described in this chapter and must be estimated using the Methods described in other chapters.

Division 4.4.1 Iron and steel production

Division 4.4.1 sets out methods for estimation of emissions from iron and steel production.

Section 4.64 (2) and (3) specify that this Division applies to an integrated steelworks, including the production of coke and iron and steel, and that the Methods for this Division apply to the estimation of the emissions from the whole of the facility.

Section 4.66 sets out Method 1 for the estimation of emissions from a facility producing iron and steel. It specifies that emissions should be estimated using a carbon mass balance approach. Method 1 utilises carbon content factors listed in Schedule 3. These carbon content factors are derived directly from the carbon dioxide emission factors listed in Schedule 1. 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.

The carbon mass balance approach requires fuels to be estimated in accordance with Criterion A – based on quantities of fuels delivered rather than consumed. This is because criteria AA or AAA cannot be utilised as changes in stocks of fuels are explicitly taken into account in the mass balance estimation directly.

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.

Section 4.64 (4) sets out that the estimation of emissions for the use of fuels as reductants is to be determined in accordance with Section 2.69, which provides guidance as to how to apportion emissions estimated using Section 4.66 (or 4.67 or 4.68) between the use of fuels combusted for energy and the use of fuels used as reductants.

Division 4.4.2 Ferro-alloy metal production

Section 4.70 sets out that all four Methods are available for this source.

Section 4.71 sets out Method 1 for emissions of carbon dioxide released from the use of fuels as carbon reductants in the production of synthetic rutile (UNFCCC Category 2.C.2). This Method is derived from the methodology used for the *National Greenhouse Accounts*.

Section 4.70(2) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

Sections 4.72 and 4.73 set out Methods 2 and 3. As for combustion of fuels, representative and unbiased samples of fuels consumed must be obtained for analysis for Method 2. 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 for solid fuels is given in Schedule 2 Examples of equivalent standards include those produced by AS, NZ, ASTM, ISO and CEN standards organisations. The standards must be in force at 1 July 2008.

Minimum frequencies of analysis for solid fuels are also provided for in Schedule 2. These frequencies correspond to those specified in the Technical Guidelines for the *Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage.

As for combustion of fuels, 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, for solid fuels, 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 and other factors should be conducted as for Method 2. Emissions may then be estimated in accordance with Method 2.

Division 4.4.3 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 GHG 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.

Method 1 for perfluorocarbon emissions is based on national average emission factors estimated from the National Greenhouse Accounts. It is intended that 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.*

Division 4.4.4 Other metal production

Section 4.92 sets out that this Division applies to the production of metal, other than iron and steel, ferro-alloy metal and aluminium, that involves the use of fuels as carbon reductants.

Section 4.93 also sets out that all four Methods are available for this source.

Section 4.94 sets out Method 1 for emissions of carbon dioxide released from the use of fuels as carbon reductants in the production of other metals (UNFCCC Category 2.B.5). This Method is derived from the methodology used for the *National Greenhouse Accounts*.

Section 4.93(2) specifies that for incidental source streams, as defined in the National Greenhouse and Energy Reporting Regulations 2008, Regulation 4.27, the Reporter may estimate emissions using a method that is consistent with the criteria identified in section 1.13: namely that the estimates are transparent, comparable, accurate and complete.

Section 4.95 and 4.96 set out Methods 2 and 3. As for combustion of fuels, representative and unbiased samples of fuels consumed must be obtained for analysis for Method 2. 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 for solid fuels is given in Schedule 2. Examples of equivalent standards include those produced by AS, NZ, ASTM, ISO and CEN standards organisations. The standards must be in force at 1 July 2008.

Minimum frequencies of analysis for solid fuels are also provided for in Schedule 2. These frequencies correspond to those specified in the Technical Guidelines for the *Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage.

As for combustion of fuels, 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, for solid fuels, 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 and other factors should be conducted as for Method 2. Emissions may then be estimated in accordance with Method 2.

Part 4.5 Industrial processes – emissions from the consumption of halocarbons and sulphur hexaflouride

Emissions of these gases arise as fugitive emissions from the use of equipment, such as refrigeration, that contain halocarbon or sulphur hexafluoride gases.

Section 4.98 sets out that there is only Method 1 for this category.

Section 4.100, together with the Regulation 4.16, limits the application of the Method to the estimation of emissions from specified equipment that also meet the following criteria:

(i) the equipment must contain a charge of specified greenhouse gases in excess of 100 kilograms;

(ii) the equipment must contain a charge with an average GWP drawn from the Regulation 2.02 in excess of 1000; and

(iii) the equipment must be used in specified industries listed in section 4.100.

The 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.

CHAPTER 5 WASTE (UNFCCC CATEGORY 6)

Part 5.1 Preliminary

Section 5.1 sets out the four parts for this chapter: (i) emissions from solid waste disposal on land (UNFCCC Category 6.A); (ii) emissions from wastewater handling (domestic and commercial (UNFCCC Category 6.B.2)); (iii) emissions from wastewater handling (industrial (UNFCCC Category 6.B.1)); and (iv) emissions from waste incineration.

Part 5.2 Emissions from solid waste disposal on land (UNFCCC Category 6.A)

Section 5.3 sets out the available methods for solid waste disposal on land – ie the operation of landfills. Methods 1, 2 and 3 are available for estimation of emissions from this source.

No Method 4 has been specified. However, it is intended that the development of a Method 4 will be the subject of further work and consultations.

Division 5.2.2 Method 1 – emissions of methane released at landfill

Section 5.4 sets out the Method 1. It is intended that emissions from solid waste disposal are estimated using data on the receipt of solid waste materials at the landfill and the Tier 2 FOD model provided in the *2006 IPCC Guidelines for National Greenhouse Gas Inventories,* except in certain circumstances specified below.

Sections 5.5-5.14 set out the data requirements to implement the Tier 2 FOD model. These data requirements reflect the complexities of the emissions generation process at landfill. The data requirements include:

(i) the total waste received at the landfill (in tonnes);

(ii) the total waste received by waste stream – being municipal waste disposal; commercial and industrial; and construction and demolition.

(iii) waste received by waste mix type – food; paper and paperboard; garden and green; wood; textiles; sludge; nappies; rubber and leather and other.

(iv) the opening stock of degradable carbon in the landfill for the first year of reporting for the facility; and

(v) the methane generation constants (k values).

For all but (i) the total waste received at the landfill, and (iv), the opening stock of degradable carbon for the first year of reporting, default values have been specified in the Determination and which may be applied in the absence of any facility-specific information to provide an estimate of emissions from the landfill. In practice this means that an estimate of emissions may be obtained with information on total waste received in the year of operation and, for (iv), information on average volumes of waste received over the lifetime of the facility prior to the first year of reporting.

Sections 5.5 – 5.8 set out the criterion available for the data for total waste volumes received that is required for the estimation of emissions using the IPCC Tier 2 FOD model. The data may, in principle, be classified according to similar criteria set out for the classification of quantities of fuels and other raw materials.

Sections 5.9 – 5.10 set out data requirements for the composition of the waste data split between waste streams. Data required include volumes of (a) municipal solid waste (b) commercial and industrial and (c) construction and demolition.

It is intended that Reporters should adopt the classifications adopted for state-based levy systems where applicable and, if not:

- class waste from transfer stations as commercial and industrial;
- class all council collections as municipal solid waste;
- class mixed load deliveries of domestic and commercial waste according to the dominant source.

Soil and other inorganic loads should not be reported.

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 those small number of facilities that capture methane generated by the landfill and where the estimates of the quantity of methane captured for combustion (either at the landfill or elsewhere) 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 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] x quantity of methane captured.

This mixed approach ensures that where a more accurate estimate of emissions generated by the landfill is available – ie 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.

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 for landfills. 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.

Division 5.2.3 Method 2 – emissions of methane released at landfill

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.*

Section 5.16 sets out that sampling of landfill gas flow rates should be conducted in accordance with the general sampling provisions of the Determination. Analysis of landfill gas flow production rates may be undertaken in accordance with US Environment Protection Agency *Method 2E*, *Determination of landfill gas flow production rates*.

It is not intended that this method represent a periodic or continuous monitoring approach.

Division 5.2.4 Method 3 – emissions of methane released at landfill

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.

Division 5.2.5 Solid Waste at landfills - flaring

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.

Division 5.2.6 Biological treatment of solid waste

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.*

Part 5.3 Emissions from wastewater handing – domestic and commercial (UNFCCC Category 6.B.2)

Division 5.3.1 Preliminary

Emissions of methane and nitrous oxide occur at wastewater handling facilities. Methods 1, 2 and 3 are described for methane and nitrous oxide emission sources.

Division 5.3.1 Method 1 - emissions of methane from wastewater handing – 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 those small number of 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) 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.

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.

Division 5.3.3 Method 2 - emissions of methane from wastewater handing – 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 Determination 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.

Division 5.3.4 Method 3 - emissions of methane from wastewater handing – 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.

Division 5.3.5 Emissions of nitrous oxide from wastewater handing – domestic and commercial

Section 5.31 sets out Method 1 for the estimation of nitrous oxide emissions. The method is derived from the method used for the *National Greenhouse Accounts*.

Division 5.3.6 Emissions of nitrous oxide from wastewater handing – domestic and commercial

Section 5.32-5.35 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.

Division 5.3.7 Emissions of nitrous oxide from wastewater handing – 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.

Division 5.3.8 Emissions from wastewater handing – 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 more closely in order to estimate the quantity of methane flared more accurately. .

Part 5.4 Emissions from wastewater handing – industrial (UNFCCC Category 6.B.1)

Division 5.4.1 Preliminary

Emissions of methane occur at wastewater handling – industrial facilities. Methods 1, 2 and 3 are described for methane emissions.

Division 5.4.2 Method 1 - emissions of methane from wastewater handing – industrial

Section 5.42 sets out Method 1 for methane emissions from wastewater handling – industrial. It s intended that this method applies to industries producing products listed in 5.42 (8).

As for domestic and commercial wastewater handling facilities, Method 1 for wastewater handling is based on the *National Greenhouse Accounts* methods, except in certain circumstances.

The method to be applied in these circumstances is as for the solid waste disposal method set out in section 5.4.

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.

Division 5.4.3 Method 2 - emissions of methane from wastewater handing – 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 the Determination and analysis conducted in accordance with listed Australian or international standards or an equivalent standard.

Division 5.4.4 Method 3 - emissions of methane from wastewater handing – domestic and commercial

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.

Division 5.4.5 Emissions from wastewater handing – industrial - flaring

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 composition of the gases in the fuel in accordance with the provisions of chapter 2.

CHAPTER 6 ENERGY

Chapter 6 sets out the estimation of the energy content of energy produced and consumed from the operation of a facility during a year.

Part 6.1 Production

Section 6.2 sets out the requirements for estimating the quantity of energy produced from solid, gaseous and liquid fuels.

Section 6.2 also specifies that electricity produced for use in the operation of the facility is the difference between the amount of electricity produced by the electricity generating unit as measured at the unit's terminals and the sum of the electricity supplied to the electricity grid and electricity supplied outside the grid (if applicable).

Electricity produced for use outside the operation of the facility is the sum of the amount of electricity produced by the electricity generating unit for the facility as measured at the unit's terminals and the sum of the electricity supplied to the electricity grid and electricity supplied outside the grid (if applicable).

Electricity is to be measured in accordance with the metering requirements set out in Chapter 7 of the National Electricity Rules or metering requirements applicable to the region in which the facility is located.

An example of metering requirements applicable to a region is the Wholesale Electricity Market Amending Rules in Western Australia's South West Interconnected System.

These requirements are generally sourced from definitions contained in the National Electricity Rules and current measurement requirements under the *Generator Efficiency Standards* program.

Section 6.3 sets out the method for estimating the energy content of fuels and energy commodities produced.

Estimates of energy produced do not enter emission calculations and will be used for statistical purposes.

Further development of these specifications may be necessary, however, depending on the development of policy in relation to emissions trading and, in particular, the use of the concept of upstream liability.

Part 6.2 Consumption

This part sets out the estimation of the energy content of fuels and energy commodities consumed. 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. Consequently this data will serve the dual purpose of estimation of energy consumed and the estimation of emissions.

CHAPTER 7 SCOPE 2 EMISSIONS

Chapter 7 sets out the method for the estimation of scope 2 emissions arising from the purchase of electricity from an electricity grid. This method has been used by the Greenhouse Challenge Plus for over a decade. The method accommodates electricity measured either in kilowatt hours or gigajoules.

For the purposes of the calculation of scope 2 emissions, for an electricity transmission or distribution network the quantity of electricity purchased and consumed during the year is equivalent to the quantity of electricity losses for that transmission or distribution network.

The scope 2 emission factors provided in Part 6 of Schedule 1 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*^{t}i) is used to calculate scope 2 emissions and is defined for state i and financial year t:

$$EFG\ scope2_i^t = \frac{Combustion\ emissions\ from\ electricity\ consumed\ from\ the\ grid\ in\ state\ i\ (CE\_C_i^t)}{Electricity\ sent\ out\ consumed\ from\ the\ grid\ in\ state\ i\ (ESO\_C_i^t)}$$

Where

'combustion emissions from electricity consumed from the grid in state i' (CE_Cti) and 'energy sent out consumed from the grid in state i' (ESO_Cti) are defined in terms of the state's electricity grid generation, imports and exports as follows:

$$CE\_C_i^t = CE\_P_i^t + \sum^{j}\left(\frac{ESO\_M_{j,i}^t}{ESO\_P_j^t} \times CE\_P_j^t\right) - \sum^{k}\left(\frac{ESO\_X_{i,k}^t}{ESO\_P_i^t} \times CE\_P_i^t\right)$$

$$ESO\_C_i^t = ESO\_P_i^t + \sum^{j} ESO\_M_{j,i}^t - \sum^{k} ESO\_X_{i,k}^t$$

where

CE_Pti is the total CO2-e emissions from fuel combustion at generation attributed to the electricity generated/produced for the grid in state i in financial year t

CE_Ptj is the total CO2-e emissions from fuel combustion at generation attributed to the electricity generated for the grid in state j in financial year t

ESO_Mtj,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_Xti,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_Ptj is the total energy sent out on the grid that is generated within state j in financial year t

ESO_Pti 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 from Department of Climate Change surveys supplemented with data from the National Electiricty Market Management Company, ABARE and the Energy Supply Association of Australia. Emission estimates are taken from the National Greenhouse Accounts. Further detail on the approach to calculating electricity emission estimates is available in:

- *National Inventory Report 2006*, Volume 1;
- *Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006 – Energy (Stationary Sources).*

Example

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. The Reporter uses the method specified for determining scope 2 CO_2-equivalent emissions from the consumption of electricity *(Section 7.2).* Emissions are estimated as follows:

$$Y = Q \text{ x } EF/1000$$

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. **In this case it is 0.89 kg CO_2-e/kWh for NSW and 0.91 CO2-e/kWh for QLD.**

Therefore, to calculate Scope 2 emissions :

For NSW operations

=(11,300,000 x 0.89)/1000

= 10,057 t Scope 2 CO_2-e

For QLD operations

=(14,600,000 x 0.91)/1000

= 13,286 t Scope 2 CO_2-e

CHAPTER 8 ASSESSMENT OF UNCERTAINTY

Chapter 8 provides guidance on how to estimate uncertainty of the emission estimates for the facilities that make up a corporation.

The uncertainty of emissions estimates is to be worked out in accordance with the publication known as *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 on Sustainable Development.

Estimates need only provide for statistical uncertainty in accordance with the protocol. Uncertainty must be estimated at a 95% confidence level.

The tables in Section 8.6 set out the uncertainty levels for the carbon dioxide emission factors used in Method 1 calculations for the combustion of a fuel. For methane and nitrous oxide emissions released from fuel combustion, estimated using method 1, the uncertainty level is 50%. It is intended that these default uncertainty levels for emission factors would be utilised in the estimation of the uncertainty for a corporation's emissions estimates.

Section 8.7 provides uncertainty levels for fugitive emissions estimated using method 1.

Section 8.8 provides uncertainty levels for industrial processes emissions estimated using method 1.

Reporters that estimate emission factors using Methods 2 or 3 must estimate their own estimate of uncertainty in accordance with the provisions cited above.

It is intended that additional guidance to assist in standardising the estimation of uncertainty process will be provided at a later date.

SCHEDULE 1 ENERGY CONTENT AND EMISSION FACTORS

Schedule 1 sets out the energy content and emission factors for use in the estimation of emissions from fuel combustion using Method 1. This explanation provides additional information on the sources of each of the factors. In general, energy content factors have been drawn from the Australian Bureau of Agricultural and Resource Economics (ABARE) Energy Statistics. In general, emission factors have been derived from the *National Greenhouse Accounts* or, in the case of some fuels with smaller consumption levels, factors have been derived from the *2006 IPCC Guidelines for National Greenhouse Gas Inventories*. A note on the source for each fuel is provided for each item number.

Note Under the 2006 IPCC Guidelines, the emission factor for CO_2 released from combustion of biogenic carbon fuels is zero.

Part 1 Fuel combustion — solid fuels and certain coal-based products

Item	**Fuel combusted**	**Energy content factor GJ/t**	**Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)**		
			CO_2	**CH_4**	**N_2O**
1	Black coal (other than that used to produce coke)	27.0	88.2	0.03	0.2
2	Brown coal	10.2	92.7	0.01	0.4
3	Coking coal	30.0	90.0	0.02	0.2
4	Brown coal briquettes	22.1	93.3	0.06	0.3
5	Coke oven coke	27.0	104.9	0.03	0.2
6	Coal tar	37.5	81.0	0.02	0.3
7	Solid fossil fuels other than those mentioned in items 1 to 5	22.1	93.3	0.06	0.3
8	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	26.3	79.9	0.02	0.2
9	Non-biomass municipal and industrial materials, if recycled and combusted to produce heat or electricity	10.5	85.4	0.6	1.2
10	Dry wood	16.2	0.0	0.08	1.2
11	Green and air dried wood	10.4	0.0	0.08	1.2
12	Sulphite lyes	12.4	0.0	0.06	0.6
13	Bagasse	9.6	0.0	0.2	1.3

Item	**Fuel combusted**	**Energy content factor GJ/t**	**Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)**		
			CO_2	**CH_4**	**N_2O**
14	Biomass municipal materials, if recycled and combusted to produce heat or electricity	12.2	0.0	0.6	1.2
15	Charcoal	31.1	0.0	4.0	1.2
16	Primary solid biomass fuels other than those mentioned in items 10 to 15	12.2	0.0	0.6	1.2

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

Part 2 Fuel combustion —gaseous fuels

Item	**Fuel combusted**	**Energy content factor (GJ/m^3 unless otherwise indicated)**	**Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)**		
			CO_2	**CH_4**	**N_2O**
17	Natural gas distributed in a pipeline	39.3×10^{-3}	51.2	0.1	0.03
18	Coal seam methane that is captured for combustion	37.7×10^{-3}	51.1	0.2	0.03
19	Coal mine waste gas that is captured for combustion	37.7×10^{-3}	51.6	5.0	0.03
20	Compressed natural gas	39.3×10^{-3}	51.2	0.1	0.03
21	Unprocessed natural gas	39.3×10^{-3}	51.2	0.1	0.03
22	Ethane	57.5×10^{-3}	56.2	0.02	0.03
23	Coke oven gas	18.1×10^{-3}	36.8	0.03	0.06
24	Blast furnace gas	4.0×10^{-3}	232.8	0.02	0.03
25	Town gas	39.0×10^{-3}	59.9	0.03	0.03
26	Liquefied natural gas	25.3 GJ/kL	51.2	0.1	0.03
27	Gaseous fossil fuels other than those mentioned in items 17 to 26	39.3×10^{-3}	51.2	0.1	0.03
28	Landfill biogas that is captured for combustion (methane only)	37.7×10^{-3}	0.0	4.8	0.03
29	Sludge biogas that is captured for combustion (methane only)	37.7×10^{-3}	0.0	4.8	0.03

Item	Fuel combusted	Energy content factor (GJ/m^3 unless otherwise indicated)	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	CH_4	N_2O
30	A biogas that is captured for combustion, other than those mentioned in items 28 and 29 (methane only)	37.7 x 10^{-3}	0.0	4.8	0.03

Part 3 Fuel combustion —liquid fuels and certain petroleum-based products for stationary energy purposes

(section 7.4)

Item	Fuel combusted	Energy content factor (GJ/kL unless otherwise indicated)	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	CH_4	N_2O
31	Petroleum based oils (other than petroleum based oil used as fuel)	38.8	27.9	0.0	0.0
32	Petroleum based greases	38.8	27.9	0.0	0.0
33	Crude oil including crude oil condensates	45.3 GJ/t	68.9	0.06	0.2
34	Other natural gas liquids	46.5 GJ/t	60.4	0.06	0.2
35	Gasoline (other than for use as fuel in an aircraft)	34.2	66.7	0.2	0.2
36	Gasoline for use as fuel in an aircraft	33.1	66.3	0.2	0.2
37	Kerosene (other than for use as fuel in an aircraft)	37.5	68.2	0.01	0.2
38	Kerosene for use as fuel in an aircraft	36.8	68.9	0.01	0.2
39	Heating oil	37.3	68.8	0.02	0.2
40	Diesel oil	38.6	69.2	0.1	0.2
41	Fuel oil	39.7	72.9	0.03	0.2
42	Liquefied aromatic hydrocarbons	34.4	69.0	0.02	0.2
43	Solvents if mineral turpentine or white spirits	34.4	69.0	0.02	0.2
44	Liquefied petroleum gas	25.7	59.6	0.1	0.2
45	Naphtha	31.4	69.0	0.00	0.02
46	Petroleum coke	34.2 GJ/t	90.8	0.06	0.2

Item	Fuel combusted	Energy content factor (GJ/kL unless otherwise indicated)	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	CH_4	N_2O
47	Refinery gas and liquids	42.9 GJ/t	54.2	0.02	0.03
48	Refinery coke	34.2 GJ/t	90.8	0.06	0.2
49	Petroleum based products other than: (a) petroleum based oils and petroleum based greases mentioned in items 31 and 32; and (b) the petroleum based products mentioned in items 33 to 48.	34.4	69.0	0.02	0.2
50	Biodiesel	34.6	0.0	0.06	0.2
51	Ethanol for use as a fuel in an internal combustion engine	23.4	0.0	0.06	0.2
52	Biofuels other than those mentioned in items 50 and 51	23.4	0.0	0.06	0.2

Part 4 Fuel combustion —fuels for transport energy purposes

(section 7.4)

Division 4.1 Fuel combustion —fuels for transport energy purposes

Item	Fuel combusted	Energy content factor (GJ/kL unless otherwise indicated)	Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	CH_4	N_2O
53	Gasoline (other than for use as fuel in an aircraft)	34.2	66.7	0.6	2.3
54	Diesel oil	38.6	69.2	0.2	0.5
55	Gasoline for use as fuel in an aircraft	33.1	66.3	0.04	0.7

Item	**Fuel combusted**	**Energy content factor** (GJ/kL unless otherwise indicated)	**Emission factor** kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	**CH_4**	**N_2O**
56	Kerosene for use as fuel in an aircraft	36.8	68.9	0.01	0.7
57	Fuel oil	39.7	72.9	0.06	0.6
58	Liquefied petroleum gas	26.2	59.6	0.6	0.6
59	Biodiesel	34.6	0.0	1.2	2.2
60	Ethanol for use as fuel in an internal combustion engine	23.4	0.0	1.2	2.2
61	Biofuels other than those mentioned in items 62 and 63	23.4	0.0	1.2	2.2
62	Natural gas (LDV)	39.3×10^{-3} GJ/m^3	51.2	5.5	0.3
63	Natural gas (HDV)	39.3×10^{-3} GJ/m^3	51.2	2.1	0.3

Division 4.2 Fuel combustion — liquid fuels for transport energy purposes for post-2004 vehicles

Item	**Fuel combusted**	**Energy content factor** GJ/kL	**Emission factor** kg CO_2-e/GJ (relevant oxidation factors incorporated)		
			CO_2	**CH_4**	**N_2O**
64	Gasoline (other than for use as fuel in an aircraft)	34.2	66.7	0.02	0.2
65	Diesel oil	38.6	69.2	0.01	0.6
66	Liquefied petroleum gas	26.2	59.6	0.3	0.3
67	Ethanol for use as fuel in an internal combustion engine	23.4	0.0	0.2	0.2

Division 4.3 Fuel combustion — liquid fuels for transport energy purposes for certain trucks

Item	**Fuel type**	**Heavy vehicles design standard**	**Energy content factor** GJ/kL	**Emission factor** kg CO_2-e/GJ (relevant oxidation factors incorporated)

				CO_2	CH_4	N_2O
68	Diesel oil	Euro iv	38.6	69.2	0.05	0.5
69	Diesel oil	Euro iii	38.6	69.2	0.1	0.5
70	Diesel oil	Euro i	38.6	69.2	0.2	0.5

Part 5 Consumption of fuels for non-energy product purposes

Item	**Fuel consumed**	**Energy content factor (GJ/t unless otherwise indicated)**	**Emission factor kg CO_2-e/GJ (relevant oxidation factors incorporated)**		
			CO_2	**CH_4**	**N_2O**
71	Solvents if mineral turpentine or white spirits	34.4 GJ/kL	Not applicable		
72	Bitumen	43.2	Not applicable		
73	Waxes	45.8	Not applicable		
74	Carbon black if used as a petrochemical feedstock	37.1	Not applicable		
75	Ethylene if used as a petrochemical feedstock	50.3	Not applicable		
76	Petrochemical feedstock other than those mentioned in items 74 and 75		Not applicable		

Part 6 Indirect (scope 2) emission factors from consumption of purchased electricity from grid

Item	**State, Territory or grid description**	**Emission factor kg CO_2-e/kWh**
77	New South Wales and Australian Capital Territory	0.89
78	Victoria	1.22
79	Queensland	0.91
80	South Australia	0.84
81	South West Interconnected System in Western Australia	0.87
82	Tasmania	0.12
83	Northern Territory	0.69

Notes on Energy and Emission Factors

1. Energy value: Source – $ABARE_1$ (washed steaming). CO_2 emission factor: Source - National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.98. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

2. Energy value: Source - AGEIS database, Department of Climate Change (based on facility reports). CO_2 emission factor: Source - AGEIS database, Department of Climate Change (based on facility reports). Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

3. Energy value: Source – $ABARE_1$ (washed coking). CO_2 emission factor: Source - National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.98. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

4. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source - AGEIS database, Department of Climate Change (based on facility reports). Oxidation factor 0.98. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

5. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.98. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

6. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change (coal tar). Oxidation factor 0.99. Non-CO2 factors: Source: AGEIS database, Department of Climate Change.

7. See (4)

8. Energy value: Source – GHD Review of Sectoral Models, Internal report to the AGO, 2006. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.98. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

9. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value.. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95. Oxidation factor 0.98. Non-CO_2 factors: Source: IPCC 2006. Derived using conversion factor of 0.95.

10. Energy value: Source: $ABARE_1$ (dry wood). Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

11. Energy value: Source: $ABARE_1$ (green wood). Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

12. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. Non-CO_2 factors: Source: IPCC 2006. Derived using conversion factor of 0.95.

13. Energy value: Source: $ABARE_1$. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

14. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. Non-CO_2 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_2 factors: Source: IPCC 2006. Derived using conversion factor of 0.95.

16. See (14)

17. Energy value: Source: $ABARE_1$ (weighted average). CO_2 emission factor: Source - AGEIS database, Department of Climate Change. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

18. Energy value: Source: $ABARE_1$ (coal seam methane). CO_2 emission factor: Source - AGEIS database, Department of Climate Change. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

19. Energy value: Source: $ABARE_1$ (coal seam methane). CO_2 emission factor: Source - AGEIS database, Department of Climate Change. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

20. See (17)

21. See (17)

22. Energy value: Source: $ABARE_2$ (average). CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.995. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

23. Energy value: Source: $ABARE_1$. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change . Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

24. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.90. Oxidation factor 0.995. Non-CO_2 factors: Source: IPCC 2006. Derived using conversion factor of 0.90.

25. Energy value: Source – $ABARE_2$ (synthetic natural gas). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.995. Non-CO_2 factors: Source: AGEIS database.

26. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source - AGEIS database, Department of Climate Change. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

27. See (17)

28. Energy value: Source – $ABARE_1$. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

29. Energy value: Source – $ABARE_1$. Non-CO_2 factors: Source: AGEIS database, Department of Climate Change.

30. See (28)

31. Energy value: Source – $ABARE_2$ (lubricants and greases). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (lubricants and greases). Oxidation factor 0.4. Non-CO_2 factors: nil.

32. Energy value: Source – $ABARE_2$ (lubricants and greases). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (lubricants and greases). Oxidation factor 0.4. Non-CO_2 factors: nil.

33. Energy value: Source – $ABARE_2$ (weighted average). CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95. Oxidation factor 0.99. Non-CO_2 factors: IPCC 2006 (Energy Industries). 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_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95. Oxidation factor 0.99. Non-CO_2 factors: IPCC 2006 (Energy Industries). Derived using conversion factor of 0.95.

35. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

36. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

37. Energy value: Source – $ABARE_2$ (power kerosene). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

38. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

39. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

40. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

41. Energy value: Source – $ABARE_2$ (low sulfur). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Derived using conversion factor of 0.95. Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

42. Energy value: Source – $ABARE_2$. Given same energy content as solvents. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (assumed same as solvents). Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

43. Energy value: Source – $ABARE_2$. CO_2 emission factor: National Inventory Report 2006, Department of Climate Change . Derived using conversion factor of 0.95. Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

44. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

45. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

46. Energy value: Source – IPCC 2006. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95. Oxidation factor 0.98. Non-CO_2 factors: IPCC 2006, Manufacturing category. Derived using conversion factor 0.95.

47. Energy value: Source – $ABARE_1$ (refinery fuel). CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95. Oxidation factor 0.99. Non-CO_2 factors: IPCC 2006. Derived using conversion factor 0.95.

48. See (46)

49. Energy value: Source – $ABARE_2$. Based on IPCC 2006, given same energy content as solvents. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (set same as solvents). Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

50. Energy value: Source – Derived from US Department of Energy. Non-CO_2 factors: IPCC 2006. Derived using conversion factor 0.95.

51. Energy value: Source – $ABARE_2$. Non-CO_2 factors: IPCC 2006. Derived using conversion factor 0.95.

52. See (51).

53. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database Department of Climate Change.

54. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database Department of Climate Change.

55. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database, Department of Climate Change.

56. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database Department of Climate Change.

57. Energy value: Source – $ABARE_2$ (low sulfur). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Derived using conversion factor of 0.95. Oxidation factor 0.99. Non-CO_2 factors: AGEIS database Department of Climate Change.

58. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: AGEIS database Department of Climate Change.

59. Energy value: Source – Derived from US Department of Energy, 2006. Non-CO_2 factors: IPCC 2006. Derived using conversion factor 0.95.

60. Energy value: Source – $ABARE_2$. Non-CO_2 factors: IPCC 2006. Derived using conversion factor 0.95.

61. See (60)

62. Energy value: Source: $ABARE_1$ (weighted average). CO_2 emission factor: Source - AGEIS database, Department of Climate Change. Non-CO_2 factors: AGEIS database, Department of Climate Change.

63. Energy value: Source: $ABARE_1$ (weighted average). CO_2 emission factor: Source - AGEIS database, Department of Climate Change. Non-CO_2 factors: AGEIS database, Department of Climate Change.

64. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

65. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change. Oxidation factor 0.99. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

66. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

67. Energy value: Source – $ABARE_2$. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

68. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

69. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

70. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change . Oxidation factor 0.99. Non-CO_2 factors: Derived from AGEIS database, Department of Climate Change.

70. Energy value: Source – $ABARE_2$.

72. Energy value: Source – $ABARE_1$.

73. Energy value: Source – $ABARE_1$.

74. Energy value: Source – $ABARE_1$.

75. Energy value: Source – $ABARE_1$.

76. NA

77-83. AGEIS database Department of Climate Change.

Notes:

$ABARE_1$ 2007 *Fuel and Electricity Survey – Fuel Codes,* Australian Bureau of Agricultural and Resource Economics www.abareconomics.com/publications_html/surveys/surveys/surveys.html, Commonwealth of Australia, Canberra.

$ABARE_2$ 2007 *Energy in Australia 2006,* produced for Department of Industry, Tourism and Resources, pages 77-79, Commonwealth of Australia ,Canberra.

Department of Climate Change (2008), *National Inventory Report 2006*, Commonwealth of Australia, Canberra

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

SCHEDULE 2 Standards and frequency of analysing energy content factor etc for solid fuels

This schedule sets out standards for analysis of solid fuels under Method 2, section 2.8. The minimum frequency of analysis set out in column 5 of the Table is derived from the *Technical Guidelines for the Generator Efficiency Standards* program, released in December 2006 by the Australian Greenhouse Office, Department of Environment and Heritage.

SCHEDULE 3 Carbon content factors for fuels

This schedule sets out carbon content factors for fuels and selected carbon containing products. The carbon factors have been derived directly from the information in Schedule 1.

Part 1 Fuel combustion — solid fuels and certain coal-based products

Item	**Fuel type**	**Carbon Content Factor tonnes of carbon/tonne fuel type**
1	Black coal (other than that used to produce coke)	0.663
2	Brown coal	0.260
3	Coking coal	0.752
4	Brown coal briquettes	0.574
5	Coke oven coke	0.789
6	Coal tar	0.837
7	Solid fossil fuels other than those mentioned in items 1 to 5	0.574
8	Industrial materials and tyres that are derived from fossil fuels, if recycled and combusted to produce heat or electricity	0.585
9	Non-biomass municipal and industrial materials if recycled and combusted to produce heat or electricity	0.250
10	Dry Wood	0
11	Green and air dried wood	0
12	Sulphite lyes	0
13	Bagasse	0
14	Biomass municipal 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

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

Part 2 Fuel combustion —gaseous fuels

Item	Fuel	Carbon Content Factor tonnes carbon/cubic metre fuel type (unless stated otherwise)
17	Natural gas if distributed in a pipeline	5.52×10^{-4}
18	Coal seam methane that is captured for combustion	5.29×10^{-4}
19	Coal mine waste gas that is captured for combustion	5.34×10^{-4}
20	Compressed natural gas	5.52×10^{-4}
21	Unprocessed natural gas	5.52×10^{-4}
22	Ethane	8.87×10^{-4}
23	Coke oven gas	1.83×10^{-4}
24	Blast furnace gas	2.55×10^{-4}
25	Town gas	6.41×10^{-4}
26	Liquefied natural gas	0.355 tonnes carbon/kilolitre fuel
27	Gaseous fossil fuels other than those mentioned in items 17 to 26	5.52×10^{-4}
28	Landfill biogas that is captured for combustion (methane only)	0
29	Sludge biogas that is captured for combustion (methane only)	0
30	A biogas that is captured for combustion, other than those mentioned in items 28 to 29 (methane only)	0

Part 3 Fuel combustion —liquid fuels and certain petroleum-based products for stationary energy purposes

(section 7.4)

Item	Fuel	Carbon Content Factor tonnes carbon/kilolitre fuel type (unless stated otherwise)
31	Petroleum based oils (other than petroleum based oils used as fuel)	0.737
32	Petroleum based greases	0.737
33	Crude oil including crude oil condensates	0.861 tonnes carbon/tonne fuel
34	Other natural gas liquids	0.774 tonnes carbon/tonne fuel
35	Gasoline (other than for use as fuel in an aircraft)	0.629
36	Gasoline for use as fuel in an aircraft	0.605
37	Kerosene (other than for use as fuel in an aircraft)	0.705
38	Kerosene for use as fuel in an aircraft	0.699
39	Heating oil	0.708
40	Diesel oil	0.736
41	Fuel oil	0.797
42	Liquefied aromatic hydrocarbons	0.654
43	Solvents if mineral turpentine or white spirits	0.654
44	Liquefied Petroleum Gas	0.422
45	Naphtha	0.597
46	Petroleum coke	0.856 tonnes carbon/tonne fuel
47	Refinery gas and liquids	0.641 tonnes carbon/tonne fuel
48	Refinery coke	0.856 tonnes carbon/tonne fuel
49	Bitumen	0.951 tonnes carbon/tonne fuel

50	Waxes	0.871 tonnes carbon/tonne fuel
51	Petroleum based products other than: (a) petroleum based oils and petroleum based greases mentioned in items 31 to 32 ; and (b) petroleum based products mentioned in items 33 to 48	0.654
52	Biodiesel	0
53	Ethanol for use as a fuel in an internal combustion engine	0
54	Biofuels other than those mentioned in items 50 to 51	0

Part 4 Consumption of fuels for non-energy product purposes

Item	Fuel	Carbon Content Factor tonnes carbon/kilolitre fuel type (unless stated otherwise)
55	Carbon black if used as a petrochemical feedstock	1 tonnes carbon/tonne
56	Ethylene if used as a petrochemical feedstock	0.856 tonnes carbon/tonne
57	Petrochemical feedstock other than those mentioned in items 55 to 56	0.856 tonnes carbon/tonne
58	Propylene	0.856 tonnes carbon/tonne
59	Polyethylene	0.856 tonnes carbon/tonne
60	Polypropylene	0.856 tonnes carbon/tonne
61	Butadiene	0.888 tonnes carbon/tonne
62	Styrene	0.923 tonnes carbon/tonne

Notes on Carbon Content Factors

1. Energy value: Source – ABARE$_1$ (washed steaming). CO$_2$ emission factor: Source - National Inventory Report 2006, Department of Climate Change (forthcoming).

2. Energy value: Source - AGEIS database, Department of Climate Change (based on facility reports). CO_2 emission factor: Source - AGEIS database, Department of Climate Change (based on facility reports).

3. Energy value: Source – $ABARE_1$ (washed coking). CO_2 emission factor: Source - National Inventory Report 2006, Department of Climate Change (forthcoming).

4. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source - AGEIS database, Department of Climate Change (based on facility reports).

5. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change (forthcoming).

6. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change (forthcoming) (coal tar).

7. See (4)

8. Energy value: Source – GHD Review of Sectoral Models, Internal report to the AGO, 2006. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change (forthcoming).

9. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value.. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.

10. Energy value: Source: $ABARE_1$ (dry wood).

11. Energy value: Source: $ABARE_1$ (green wood).

12. Energy value: Source – IPCC 2006. Derived from NCV using factor of 5% of gross calorific value. .

13. Energy value: Source: $ABARE_1$.

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: $ABARE_1$ (weighted average). CO_2 emission factor: Source - AGEIS database, Department of Climate Change.

18. Energy value: Source: $ABARE_1$ (coal seam methane). CO_2 emission factor: Source - AGEIS database, Department of Climate Change.

19. Energy value: Source: $ABARE_1$ (coal seam methane). CO_2 emission factor: Source - AGEIS database, Department of Climate Change.

20. See (17)

21. See (17)

22. Energy value: Source: $ABARE_2$ (average). CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change (forthcoming).

23. Energy value: Source: $ABARE_1$. CO_2 emission factor: Source – National Inventory Report 2006, Department of Climate Change (forthcoming).

24. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.90.

25. Energy value: Source – $ABARE_2$ (synthetic natural gas). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

26. Energy value: Source – $ABARE_1$. CO_2 emission factor: Source - AGEIS database, Department of Climate Change.

27. See (17)

28. Energy value: Source – $ABARE_1$.

29. Energy value: Source – $ABARE_1$.

30. See (28)

31. Energy value: Source – $ABARE_2$ (lubricants and greases). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming) (lubricants and greases).

32. Energy value: Source – $ABARE_2$ (lubricants and greases). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming) (lubricants and greases).

33. Energy value: Source – $ABARE_2$ (weighted average). CO_2 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_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.

35. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

36. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

37. Energy value: Source – $ABARE_2$ (power kerosene). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

38. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

39. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming). .

40. Energy value: Source – $ABARE_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

41. Energy value: Source – $ABARE_2$ (low sulfur). CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming). Derived using conversion factor of 0.95.

42. Energy value: Source – $ABARE_2$. Given same energy content as solvents. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming) (assumed same as solvents).

43. Energy value: Source – ABARE$_2$. CO_2 emission factor: National Inventory Report 2006, Department of Climate Change (forthcoming).

44. Energy value: Source – ABARE$_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming). .

45. Energy value: Source – ABARE$_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

46. Energy value: Source – IPCC 2006. CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.

47. Energy value: Source – ABARE$_1$ (refinery fuel). CO_2 emission factor: Source: IPCC 2006. Derived using conversion factor of 0.95.

48. See (46)

49. Energy value: Source – ABARE$_1$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming).

50. Energy value: Source – ABARE$_2$. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming) (assumed same as solvents).

51. Energy value: Source – ABARE$_2$. Based on IPCC 2006, given same energy content as solvents. CO_2 emission factor: Source: National Inventory Report 2006, Department of Climate Change (forthcoming) (set same as solvents).

52. Energy value: Source – Derived from US Department of Energy. Non-CO_2 factors: IPCC 2006. Derived using conversion factor 0.95.

53. Energy value: Source – ABARE$_2$. Non-CO_2 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

Notes:

ABARE$_1$ 2007 *Fuel and Electricity Survey – Fuel Codes*, Australian Bureau of Agricultural and Resource Economics www.abareconomics.com/publications_html/surveys/surveys/surveys.html, Commonwealth of Australia, Canberra.

ABARE$_2$ 2007 *Energy in Australia 2006,* produced for Department of Industry, Tourism and Resources, pages 77-79, Commonwealth of Australia ,Canberra.

Department of Climate Change (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 1: Measurement Determination References

Chapter 1 General

Part 1.1 Preliminary

1.3 (1)
The following legislation can be obtained from:
http://www.comlaw.gov.au/ComLaw/Legislation/Act1.nsf/all/search/8BFE5E5B013EF8A3CA25736A00128DE9

- *National Greenhouse and Energy Reporting Act 2007*

1.10
The following guidelines can be obtained from:
http://www.ipcc-nggip.iges.or.jp/public/gl/invs1.html

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

Part 1.2 General

1.13 (d)
The following guidelines can be obtained from:
http://www.greenhouse.gov.au/inventory/2005/national-report.html

- National Inventory Report

1.15 (4)
The following guidelines can be obtained from:
http://www.comlaw.gov.au/comlaw/Legislation/ActCompilation1.nsf/0/7C8F8B026C0DCF05CA256F71004C63B9?OpenDocument

- *National Measurement Act 1960*

Part 1.3 Method 4 – Direct measurement of emissions

Division 1.3.2 Operation of Method 4 (CEM)

1.23
The following guidelines can be obtained from:
http://www.saiglobal.com/shop/Script/search.asp

- 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 10012 – 2003 Measurement management systems – Requirements for measurement processes and measuring equipment

- ISO 10396 – 2007 Stationary source emissions – Sampling for the automated determination of gas emission concentration

The following guidelines can be obtained from:
http://www.epa.gov/ttn/emc/promgate.html

- USEPA – Method 1 – Sample and velocity traverses for stationary sources

1.24
The following guidelines can be obtained from:
http://www.saiglobal.com/shop/Script/search.asp

- ISO 10780 – 1994 Stationary source emissions – Measurement of velocity and volume of gas streams in ducts

- ISO 14164 – 1999 Stationary source emissions – Determination of the volume flowrate of gas streams in ducts – Automated method

The following guidelines can be obtained from:
http://www.epa.gov/ttn/emc/promgate.html

- USEPA – Method 2 – Determination of stack velocity and volumetric flow rate (Type S Pitot tube) (2000).

- US EPA method – 02A Direct measurement of gas volume through pipes and small ducts (2000)

1.25
The following guidelines can be obtained from:
http://www.saiglobal.com/shop/Script/search.asp

- ISO 12039 – 2001 Stationary source emissions – Determination of carbon monoxide, carbon dioxide and oxygen – Performance characteristics and calibration of automated measuring systems

The following guidelines can be obtained from:
http://www.epa.gov/ttn/emc/promgate.html

- US EPA method – 03A Determination of oxygen and carbon dioxide concentrations in emissions from stationary sources (Instrumental analyser procedure) (2006)

- US EPA Method – 03C Determination of carbon dioxide, methane, nitrogen and oxygen from stationary sources (1996)

Division 1.3.3 Operation of Method 4 (PEM)

1.30
See 1.23 of Appendix 1

1.31
See 1.24 of Appendix 1

1.32
See 1.25 of Appendix 1

Division 1.3.4 Performance characteristics of equipment

1.34 (4)
The following guidelines can be obtained from:
http://www.saiglobal.com/shop/Script/search.asp

- ISO Guide 34: 2000 General requirements for the competence of reference material producers

Chapter 2 Fuel Combustion (UNFCCC Category 1.A)

Part 2.2 Emissions released from the combustion of solid fuels

Division 2.2.3 Method 2 – emissions from solid fuels

2.7 (4)
The following standard can be obtained at:
http://www.saiglobal.com/shop/Script/search.asp

- AS 4264.4 – 1996 Coal and coke – Sampling – Determination of precision and bias

2.8 (3)
The following standards can be obtained at:
http://www.saiglobal.com/shop/Script/search.asp

- AS ISO/IEC – 17025:2005 – General requirements for the competence of testing and calibration laboratories
- AS ISO/IEC – 17025:2005 – General requirements for the competence of testing and calibration laboratories – Technical Corrigendum 1

2.9
The following standards can be obtained at:
http://www.saiglobal.com/shop/Script/search.asp

- AS 3583.2 – 1991 Methods of test for supplementary cementitious materials for use with portland cement. Method 2: Determination of moisture content

- AS 3583.3 – 1991 Methods of test for supplementary cementitious materials for use with portland cement. Method 3: Determination of loss on ignition

2.11
The following standards can be obtained at:
http://www.saiglobal.com/shop/Script/search.asp

- 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

- AS 4323.2 – 1995 Stationary source emissions – Determination of total particulate matter – Isokinetic manual sampling – Gravimetric method

Division 2.2.4 Method 3 – Solid fuels

2.12 (3)
The following standards can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- AS 4264.1 – 1995 Coal and coke – Sampling – Higher rank coal – Sampling procedure

- AS 4264.2 – 1996 Coal and coke – Sampling – Coke – Sampling procedures

- AS 4264.3 – 1996 Coal and coke – Sampling – Lower rank coal – Sampling procedures

- CEN/TS 14778 – 1 – 2005 Solid Biofuels – Sampling – Part 1– Methods For Sampling

- CEN/TS 15442 – 2006 Solid recovered fuels – Methods for sampling

Division 2.2.5 Measurement of consumption if solid fuels

2.15 (3)
The following standards can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- ASTM D 4916 – 04 Standard Practice for Mechanical Auger Sampling

- ASTM D6347/D6347M – 99 Standard Test Method for Determination of Bulk Density of Coal Using Nuclear Backscatter Depth Density Methods

Part 2.3 Emissions released from the combustion of gaseous fuels

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

2.24 (1)
The following standards can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- ISO 6974 – 1:2000 Natural gas – Determination of composition with defined uncertainty by gas chromatography. Part 1: Guidelines for tailored analysis
- ISO 6974 – 2:2001 Natural gas – Determination of composition with defined uncertainty by gas chromatography. Part 2: Measuring–system characteristics and statistics for processing of data
- ISO 6974 – 3:2000 Natural gas – Determination of composition with defined uncertainty by gas chromatography. Part 3: Determination of hydrogen, helium, oxygen, nitrogen, carbon dioxide and hydrocarbons up to C8 using two packed columns
- ISO 6974 – 4:2000 Natural gas – Determination of composition with defined uncertainty by gas chromatography. Part 4: Determination of nitrogen, carbon dioxide and C1 to C5 and C6+ hydrocarbons for a laboratory and on-line measuring system using two columns
- ISO 6974 – 5:2000 Natural gas – Determination of composition with defined uncertainty by gas chromatography. Part 5: Determination of nitrogen, carbon dioxide and C1 to C5 and C6+ hydrocarbons for a laboratory and on-line process application using three columns
- ISO 6974 – 6:2002 Natural gas – Determination of composition with defined uncertainty by gas chromatography. Part 6: Determination of hydrogen, helium, oxygen, nitrogen, carbon dioxide and C1 to C8 hydrocarbons using three capillary columns
- ISO 6976:1995 Natural gas – Calculation of calorific values, density, relative density and Wobbe index from composition
- ISO 6976 –1995 Cor 2 –1997 Natural gas - Calculation of calorific values, density, relative density and Wobbe index from composition
- ISO 6976 –1995 Cor 3 –1999 Natural gas - Calculation of calorific values, density, relative density and Wobbe index from composition
- ASTM D1826 – 94 (2003): Standard test method for calorific (heating) value of gases in natural gas range by continuous recording calorimeter
- ASTM D1945 – 03: Standard test method for analysis of natural gas by gas chromatography
- ASTM D 1946 – 90 (2006): Standard practice for analysis of reformed gas by gas chromatography
- ASTM D3588 – 98(2003): Standard practice for calculating heat value, compressibility factor, and relative density of gaseous fuels
- ASTM D7164 – 05: Standard practice for on-line/at-line heating value determination of gaseous fuels by gas chromatography

The following standards can be obtained at:
http://www.gasprocessors.com/dept.asp?dept_id=2500

- GPA 2145 – 03 Table of Physical Constants for Hydrocarbons & Other Compounds of Interest to the Natural Gas Industry
- GPA 2172 – 96 Calculation of Gross Heating Value, Relative Density, and Compressibility of Natural Gas Mixtures from Compositional Analysis
- GPA 2261 – 00 Analysis for Natural Gas & Similar Gaseous Mixtures by Gas Chromatography

2.24 (3)
See 2.8 (3) of Appendix 1

2.24 (4)
See 2.24 (1) of Appendix 1

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

2.26 (3)
The following standards can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- ISO 8943:2007 Refrigerated light hydrocarbon fluids – Sampling of liquefied natural gas – Continuous and intermittent methods
- ISO 10715:1997 – Natural gas – Sampling guidelines
- ASTM D5287 – 97 (2002): Standard Practice for Automatic Sampling of Gaseous Fuels
- ASTM D5503 – 94 (2003): Standard Practice for Natural Gas Sample-Handling and Conditioning Systems for Pipeline Instrumentation
- ASTM F307 – 02 (2007): Standard Practice for Sampling Pressurized Gas for Gas Analysis

The following standards can be obtained at:
http://www.gasprocessors.com/dept.asp?dept_id=2500

- GPA 2166 – 05 Obtaining Natural Gas Samples for Analysis by Gas Chromatography

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

2.27 (2)
The following guidelines can be obtained from:
http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html

- IPCC 2006, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2 Energy. Prepared by the National Greenhouse Gas Inventories Programme. Published: IGES, Japan.

Division 2.3.6 Measurement of quantity of gaseous fuels

2.32 (4a)
The following reports can be obtained from:
http://www.aga.org/

- American Gas Association, AGA Report No. 3, Orifice Metering of Natural Gas Part 1: General Equations & Uncertainty Guidelines (1990, 2003)
- American Gas Association, AGA Report No. 3, Orifice Metering of Natural Gas Part 2: Specification and Installation Requirements (2000, 2003)
- American Gas Association, AGA Report No. 3, Orifice Metering of Natural Gas Part 3: Natural Gas Applications (1992)
- American Gas Association, AGA Report No. 3, Orifice Metering of Natural Gas Part 4: Background, Development, Implementation Procedures and Subroutine Documentation (1992)

The following reports can be obtained from:
http://www.api.org/Publications/

- American Petroleum Institute, Manual of Petroleum Measurement Standards Part 1: General Equations & Uncertainty Guidelines (1990) (reaffirmed 2003)
- American Petroleum Institute, Manual of Petroleum Measurement Standards Part 2: Specification and Installation Requirements (2000) (reaffirmed 2006)
- American Petroleum Institute, Manual of Petroleum Measurement Standards Part 3: Natural Gas Applications (1992) (reaffirmed 2003)
- American Petroleum Institute, Manual of Petroleum Measurement Standards Part 4: Background, Development, Implementation Procedures and Subroutine Documentation (1992) (reaffirmed 2006)

2.32 (4b)
The following reports can be obtained from:
http://www.aga.org/

- American Gas Association, AGA Report No. 7, Measurement of natural gas by turbine meters (2006)

2.32 (4c)
The following standard can be obtained from:
http://www.aga.org/

- ANSI B109.3 - 2000 for Rotary-Type Gas Displacement Meters

2.32 (5)
The following standard can be obtained from:
http://www.standards.co.nz/default.htm

- NZS 5259:2004 Gas Measurement

2.32 (6)

The following legislation can be obtained from:
http://www.comlaw.gov.au/comlaw/Legislation/ActCompilation1.nsf/0/7C8F8B026C0DCF05CA256F71004C63B9?OpenDocument

- *National Measurement Act 1960*

http://www.comlaw.gov.au/ComLaw/Legislation/LegislativeInstrumentCompilation1.nsf/all/search/C38B16FFFF14000CCA2573080035AAB0

- *National Measurement Regulations 1999*

2.33 (2)
The following report can be obtained from:
http://www.aga.org/

- American Gas Association, AGA Transmission Measurement Committee Report No. 8: Compressibility Factors of Natural Gas and Other Related Hydrocarbon Gases (2003)

2.33 (3b)
See 2.36 (1) of Appendix 1

2.35 (1)
See 2.32 (4a) of Appendix 1

2.35 (2)
See 2.33 (2) of Appendix 1

2.35 (3)
See 2.32 (4c) of Appendix 1

2.37 (a)
See 2.32 (6) of Appendix 1

Part 2.4 Emissions released from the combustion of liquid fuels

Division 2.4.3 Method 2 – emissions of carbon dioxide released from the combustion of liquid fuels

2.45 (1)
The following standards can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- ASTM D240–02 (2007) – Standard test method for heat of combustion of liquid hydrocarbon fuels by bomb calorimeter

- ASTM D1298–99 Ed 2 Standard test method for density, relative density (specific gravity), or API gravity of crude petroleum and liquid petroleum products by hydrometer method

- ASTM D4809–06 – Standard test method for heat of combustion of liquid hydrocarbon fuels by bomb calorimeter (precision method)

- ASTM D5291– 02 – Standard test methods for instrumental determination of carbon, hydrogen, and nitrogen in petroleum products and lubricants

- ISO 6578-1991 Refrigerated hydrocarbon liquids - Static measurement - Calculation procedure

○ ISO 7941–1988 ISO 7941:1988 – Commercial propane and butane – Analysis by gas chromatography

2.45 (3)
See 2.8 (3) of Appendix 1

Division 2.4.4 Method 3 – emissions of carbon dioxide released from the combustion of liquid fuels

2.47 (3)
The following standards can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- ASTM D1265–05: Standard Practice for Sampling Liquefied Petroleum (LP) Gases (Manual Method)

- ASTM D4057– 06 – Standard Practice for Manual Sampling of Petroleum and Petroleum Products

- ASTM D4177–95(2005) – Standard Practice for Automatic Sampling of Petroleum and Petroleum Products

- ISO 3170:2004 – Petroleum liquids – Manual sampling

- ISO 3171:1988 – Petroleum liquids – Automatic pipeline sampling

○ ISO 4257:2001 – Liquefied petroleum gases — Method of sampling

Part 2.5 Emissions released from fuel use by certain industries

Division 2.5.1 Energy – manufacture of solid fuels (coke ovens)

2.56 (2)
The following report can be obtained from:
http://ghg.api.org/

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

Part 2.6 Blended fuels

2.66 (1b)
The following standards can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- ASTM D6866.06a – Determining the Bio-based Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis

- CEN TS 15440–2006 Solid Recovered Fuels – Method for the Determination of Biomass Content

2.67 (b)
See 2.66 (1b) of Appendix 1

Part 2.7 Estimation of energy for certain purposes

2.70 (2)
The following report can be obtained from:
http://www.ghgprotocol.org/calculation-tools/all-tools

World Business Council for Sustainable Development / World Resources Institute, Allocation of Emissions from a Combined Heat and Power (CHP) Plant – Guide to calculation worksheets (September 2006) v1.0

2.70 (4)
See 2.70 (2) of Appendix 1

Chapter 3 Fugitive emissions from fuels (UNFCCC Category 1.B)

Part 3.2 Coal mining

Division 3.2.2 Underground mines

3.9
See part 1.3 of Appendix 1 for AS and USEPA standards relating to location of sampling positions

The following legislation can be obtained from:

Applicable New South Wales legislation
http://www.legislation.nsw.gov.au/maintop/scanact/inforce/NONE/0

- *Coal Mine Health and Safety Act 2002*

- *Coal Mine Health and Safety Regulation 2006*

Applicable Queensland legislation
http://www.legislation.qld.gov.au/OQPChome.htm

- *Coal mining safety and health Act 1999*

- *Coal mining safety and health regulation 2001*

3.10
See part 1.3 of Appendix 1 for USEPA and ISO standards relating to measurement of volumetric flow rate
See 3.9 of Appendix 1 for legislation references

3.11
See part 1.3 of Appendix 1 for USEPA standards relating to measurement of gas concentrations and composition
See 3.9 of Appendix 1 for legislation references

Division 3.2.3 Open cut mines

3.25
The following standards can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- AS 2519 – 1993 Guide to the technical evaluation of higher rank coal deposits
- AS 3980 – 1999 Guide to the determination of gas content of coal – Direct desorption method

3.26
The following standards can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- AS 2519 – 1993 Guide to the technical evaluation of higher rank coal deposits
- AS 2617 – 1996 Sampling from coal seams

Division 3.2.4 Decommissioned underground mines

3.35
See 3.26 of Appendix 1

Part 3.3 Oil and natural gas: fugitive emissions

Division 3.3.3 Crude oil production

3.50 (1) & (2)
See 2.56 (2) of Appendix 1

Division 3.3.4 Crude oil transport

3.60 (1) & (2)
See 2.56 (2) of Appendix 1

Division 3.3.5 Crude oil refining

3.64 (1) & (2)
See 2.56 (2) of Appendix 1

3.66 (1b)
See 2.56 (2) of Appendix 1

Division 3.3.6 Natural gas production and processing (other than emissions that are vented or flared)

3.73 (1) & (2)
See 2.56 (2) of Appendix 1

Division 3.3.7 Natural gas transmission

3.77 (1) & (2)
See 2.56 (2) of Appendix 1

Division 3.3.8 Natural gas distribution

3.81 (1) & (2)

See 2.56 (2) of Appendix 1

Division 3.3.9 Natural gas production and processing (emissions that are vented or flared)

3.84
See 2.56 (2) of Appendix 1

Chapter 4 Industrial Processes Emissions (UNFCCC Category 2)

Part 4.2 Industrial processes – mineral products

Division 4.2.1 Cement clinker production

4.6 (4)
See 2.7 (4) of Appendix 1

4.7 (2)
The following guidelines can be obtained from:
http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html

- IPCC 2006, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 3 Industrial process and product use. Prepared by the National Greenhouse Gas Inventories Programme, Eggleston H.S., Buendia L., Miwa K., Ngara T., and Tanabe K. (eds). Published: IGES, Japan.

4.8 (1)
See 4.7 (2) of Appendix 1

4.10 (2)
See 4.7 (2) of Appendix 1

Division 4.2.2 Lime production

4.15 (4)
See 2.7 (4) of Appendix 1

4.16 (2)
See 4.7 (2) of Appendix 1

4.17 (1)
See 4.7 (2) of Appendix 1

Division 4.2.3 Other uses of carbonates

4.22

See 4.7 (2) of Appendix 1

4.23 (1)
See 4.7 (2) of Appendix 1

4.24 (4)
See 2.7 (4) of Appendix 1

4.25 (2)
See 4.7 (2) of Appendix 1

Part 4.3 Industrial processes – chemical industry

Division 4.3.3 Adipic acid production

4.50 (1)
See 4.7 (2) of Appendix 1

Division 4.3.4 Carbide production

4.52 (1)
See 4.7 (2) of Appendix 1

Part 4.4 Industrial processes – metal industry

Division 4.4.4 Aluminium (perfluoronated carbon compound emissions)

4.86
The following document can be obtained at:
http://www.world-aluminium.org/?pg=140

- US EPA, International Aluminium Institute (2003), *Protocol for Measurement of Tetrafluoromethane* (CF_4) *and Hexafluoroethane* (C_2F_6) *Emissions from Primary Aluminium Production.*

4.87
See 4.86 of Appendix

4.90
See 4.86 of Appendix

4.91
See 4.86 of Appendix

Chapter 5 Waste (UNFCCC Category 6)

Part 5.2 Emissions released from solid waste disposal on land – UNFCCC Category 6.A

Division 5.2.2 Method 1 – emissions of methane released from landfills

5.4 (5)
The following document can be obtained at:
http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol5.html

- IPCC 2006, 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 5 Waste. Prepared by the National Greenhouse Gas Inventories Programme. Published: IGES, Japan.

Division 5.2.3 Method 2 – emissions of methane released from landfills

5.15 (2)

The following document can be obtained at:
http://www.ipcc-nggip.iges.or.jp/public/gp/english/index.html

- IPCC 2000, 2000 IPCC Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories, Volume 5 Waste. Prepared by the National Greenhouse Gas Inventories Programme. Published: IGES, Japan.

5.17 (2)
The following document can be obtained at:
http://www.epa.gov/ttn/emc/promgate.html

- USEPA – Method 2E – Determination of landfill gas production flow rates

5.17 (3)
The following document can be obtained at:
http://www.epa.gov/ttn/emc/promgate.html

- USEPA – Method 3C – Determination of carbon dioxide, methane, nitrogen and oxygen from stationary sources

Division 5.2.4 Method 3 – emissions of methane released from solid waste at landfills

5.18 (2)
See 5.17 (2) of Appendix 1

Division 5.2.6 Biological treatment of solid waste

5.22 (1)
See 5.4 (5) of Appendix 1

Part 5.3 Emissions from wastewater handling (domestic and commercial) – UNFCCC Category 6.B.2

Division 5.3.3 Method 2 – methane released from wastewater handling (domestic and commercial)

5.28 (1)
The following standard can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- ISO 6060:1989 – Water quality – Determination of the chemical oxygen demand

The following standards can be obtained at:
http://www.apha.org/searchresults.htm?query=standard%20methods%20for%20the%20examination%20of%20water%20and%20wastewater

- APHA. 1995. Standard methods for the examination of water and waste water. 19th Edition, American Public Health Association, USA.

5.28 (2)
The following standard can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- AS4351.5 – 1996: Biodegradability – Organic compounds in an aqueous medium – Determination by analysis of biochemical oxygen demand (closed bottle test)

The following standards can be obtained at: http://www.apha.org/searchresults.htm?query=standard%20methods%20for%20the%20examination%20of%20water%20and%20wastewater

- APHA. 1995. Standard methods for the examination of water and waste water. 19th Edition, American Public Health Association, USA.

Division 5.3.4 Method 3 – methane released from wastewater handling (domestic and commercial)

5.30 (2)
The following standard can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- AS/NZS 5667.10:1998 – Water Quality – Sampling. Part 10: Guidance on sampling of waste waters

Division 5.3.6 Method 2 – emissions of nitrous oxide released from wastewater handling (domestic and commercial)

5.34 (1)
The following standard can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- ISO 11905-1-1997 Water quality - Determination of nitrogen - Part 1- Method using oxidative digestion with peroxodisulfate

The following standards can be obtained at: http://www.apha.org/searchresults.htm?query=standard%20methods%20for%20the%20examination%20of%20water%20and%20wastewater

- APHA. 1995. Standard methods for the examination of water and waste water. 19th Edition, American Public Health Association, USA.

5.34 (2)
The following standard can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- EN 13342: 2000 Characterization of sludges - Determination of kjeldahl nitrogen

The following standards can be obtained at: http://www.apha.org/searchresults.htm?query=standard%20methods%20for%20the%20examination%20of%20water%20and%20wastewater

- APHA. 1995. Standard methods for the examination of water and waste water. 19th Edition, American Public Health Association, USA.

Division 5.3.7 Method 3 – emissions of nitrous oxide released from wastewater handling (domestic and commercial)

5.36 (2)
See 5.30 (2) of Appendix 1

5.36 (3)
The following standard can be obtained at: http://www.saiglobal.com/shop/Script/search.asp

- ISO 5667-13-1997 Water quality - Sampling - Part 13- Guidance on sampling of sludges from sewage and water treatment works

Part 5.4 Emissions from wastewater handling (industrial) – UNFCCC Category 6.B.1

Division 5.4.3 Method 2 – methane released from wastewater handling (industrial)

5.40 (1)
See 5.28 (1) of Appendix 1
5.40 (2)
See 5.28 (2) of Appendix 1

Division 5.4.4 Method 3 – methane released from wastewater handling (industrial)

5.42 (2)
See 5.30 (2) of Appendix 1
Chapter 6 Energy

Part 6.1 Production

6.2 (3)
http://www.aemc.gov.au/rules.php

- *National Electricity Rules* made under the National Electricity Law set out in the *National Electricity (South Australia) Act 1996.*

Chapter 8 Estimation of Uncertainty

Part 2 Rules for assessment of uncertainty

8.3 (1)
http://www.ghgprotocol.org/calculation-tools/all-tools

- WBCD/WRI, *GHG Protocol guidance on uncertainty assessment in GHG inventories and calculating statistical parameter uncertainty*. World Resources Institute and the World Business Council on Sustainable Development. September 2003 v1.0.

8.4 Tables 1 – 4
The following guidelines can be obtained from:
http://www.ipcc-nggip.iges.or.jp/public/2006gl/index.html

- IPCC 2006, 2006 IPCC Guidelines for National Greenhouse Gas Inventories. Prepared by the National Greenhouse Gas Inventories Programme. Published: IGES, Japan.

Schedule 2
The following standards can be purchased at:
http://www.saiglobal.com/shop/Script/search.asp

- AS 1038.1 – 2001 Coal and coke – Analysis and testing – Higher rank coal – Total moisture (supersedes 1038.1 – 1992)

- AS1038.2 – 2002 Coal and coke – Analysis and testing – coke – total moisture
- AS 1038.3 – 2000 Coal and coke – Analysis and testing – Proximate analysis of higher rank coal

- AS 1038.5 – 1998 Coal and coke – Analysis and testing - Gross calorific value
- AS 1038.6.1 – 1997 Coal and coke – Analysis and testing – Higher rank coal and coke – Ultimate analysis – Carbon and hydrogen

- AS 1038.6.4 – 2005 Coal and coke – Analysis and testing – Higher rank coal and coke – Ultimate analysis – Carbon, hydrogen and nitrogen – Instrumental method

- AS 2434.1 – 1999 Methods for the analysis and testing of lower rank coal and its chars –Determination of the total moisture content of lower rank coal

- AS 2434.6 – 2002 Methods for the analysis and testing of lower rank coal and its chars – Lower rank coal – Ultimate analysis – Classical methods (supersedes AS2434.6.1-1986)

- AS 2434.8 – 2002 Methods for the analysis and testing of lower rank coal and its chars – Lower rank coal – Determination of ash (supersedes AS2434.8 – 1993)

- CEN1TS 15400 – 2006 Solid Recovered Fuels – Methods for the Determination of Calorific Value

- CEN/TS 15403 – 2006 Solid Recovered Fuels – Methods for the Determination of ash Content

- CEN/TS 15407 – 2006 Solid Recovered Fuels – Method for the Determination of Carbon (c), Hydrogen (h) and Nitrogen (N) content

- CEN/TS 15414 – 3 – 2006 Solid Recovered Fuels – Determination of Moisture Content Using the Oven dry Method