Australian Government

Department of Climate Change

AUSTRALIAN METHODOLOGY FOR THE ESTIMATION OF GREENHOUSE GAS EMISSIONS AND SINKS 2006

ENERGY
(FUGITIVE FUEL EMISSIONS)

National Greenhouse Gas Inventory Committee

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http://www.climatechange.gov.au/inventory.

The Intergovernmental Panel on Climate Change *Guidelines for National Greenhouse Gas Inventories* are at:

http://www.ipcc-nggip.iges.or.jp.

Suggestions and comments would be appreciated. They should be addressed to the Manager, Australian National Greenhouse Gas Inventory, Emissions Analysis Team, Department of Climate Change or sent to ageis@climatechange.gov.au.

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FOREWORD

This inventory methodology workbook presents the Australian methodology to estimate greenhouse gas emissions and sinks for emissions from industrial processes. It is part of a series that includes:

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006: Energy (Stationary Sources)

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006: Energy (Transport)

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006: Energy (Fugitive Fuel Emissions)

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006: Industrial Processes

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006: Solvents

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006: Agriculture

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006: Land use, land use change and forestry

Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006: Waste

The methodology in this workbook was developed with input from researchers and other experts specialising in greenhouse gas emissions from industrial processes. It is based on the methodology first presented in the *Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Industrial Process Emissions, Workbooks 7.0 and 7.1,* National Greenhouse Gas Inventory Committee, (1994 and 1998), Canberra. Contributors to the development of the original methodology are listed in those Workbooks.

The development of Australia's inventory methodologies and the compilation of Australia's national inventories are guided by the National Greenhouse Gas Inventory Committee, comprising representatives of the Australian, State and Territory governments.

ABBREVIATIONS

ABARE	Australian Bureau of Agricultural and Resource Economics
AGA	Australian Gas Association
ANZMEC	Australia and New Zealand Minerals and Energy Council
APPEA	Australian Petroleum Production and Exploration Association
E&P Forum	Oil Industry Exploration and Production Forum
GCV	Gross calorific value
HHV	Higher heating value
IPCC	Intergovernmental Panel on Climate Change
LNG	Liquefied natural gas
LPG	Liquid petroleum gas
N/A	Not applicable
N/AV	Not available
NGGI	National Greenhouse Gas Inventory
NMVOC	Non-methane volatile organic compound
OECD	Organisation for Economic Co-operation and Development
UAG	Unaccounted for gas
USEPA	United States Environmental Protection Agency

UNITS

The units mainly used in this workbook are joules (J), litres (l), grams (g), tonnes (t) and cubic metres (m^3), together with their multiples. Standard metric prefixes used in this workbook are:

kilo (k)	=	10^3 (thousand)
mega (M)	=	10^6 (million)
giga (G)	=	10^9 (billion)
tera (T)	=	10^{12}
peta (P)	=	10^{15}

The abbreviation N/A means not applicable, N/AV means not available and N/E means not estimated. 0.0 denotes a negligible or zero amount.

One gigagram (Gg) equals one thousand tonnes, or one kilotonne (kt). One million tonnes or one megatonne (Mt) is equal to one thousand gigagrams. One kilogram per gigajoule (kg/GJ) is equal to one gigagram per petajoule (Gg/PJ).

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INTRODUCTION

Australia's national greenhouse gas inventory is prepared annually by the Department of Climate Change in accordance with the IPCC *Revised 1996 Guidelines for National Greenhouse Gas Inventories* (IPCC 1997), and the *IPCC Good Practice Guidance* (IPCC 2000), and taking into account Australian conditions. Documenting the methods used in the estimation of emissions for the inventory enhances transparency and improves the comparability of estimates with those reported in the inventories produced by other countries.

The methods and emission factors used by Australia to estimate annual fugitive emissions of greenhouse gases from activities associated with fuel production, transmission, storage and distribution are documented in this workbook. It covers the UNFCCC reporting categories *solid fuels* (1B1), *oil* (1B2a), *gas* (1B12b) and *oil and gas venting and flaring* (1B2c).

Fugitive emissions may occur at any stage of the process of extraction, refining, transmission, storage, distribution and retail, comprising principally carbon dioxide (CO_2), methane (CH_4) and non-methane volatile organic compounds (NMVOCs).

This workbook is one of three workbooks for the Energy sector. The estimation of greenhouse gas emissions from combustion of fuels in the Energy sector is covered in the *Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006: Energy (Stationary Sources)*. Greenhouse gas emissions from transport activities are included in the *Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006: Energy (Transport)*.

General approach

For coal, oil and gas related emissions the IPCC methodology suggests three different estimation methods, making use of increasingly detailed information about emissions. These methods are termed *Tier 1*, *Tier 2* and *Tier 3* approaches.

The *Tier 1* approach, which is the least detailed, calculates total emissions of each greenhouse gas from each fossil fuel as the product of total national throughput of the fuel and a single average emission factor for the gas and fuel concerned. Relevant throughput parameters are national underground coal production, national crude oil production and national natural gas production. Emission factors may be either a global default value or a national value considered to be representative for the country.

The *Tier 2* approach embodies more detailed factors, eg different emission factors for groups of coal mines. The *Tier 3* approach is based on the characteristics of individual production facilities or components of facilities, and may include measurements of actual emissions.

Most emission factors are related to throughput measured in physical units (tonnes, litres or cubic metres). Where emission factors are related to energy throughput, the energy content of fuels is expressed in terms of gross calorific value (GCV).

The estimation methods and source of emission factors used in the fugitive emissions sector of the Australian inventory are summarised in Table 1.

Table 1: Summary of Estimation methods and emission factors

Greenhouse gas source and sink categories	CO_2		CH_4		N_2O	
	Method applied	Emission factor	Method applied	Emission factor	Method applied	Emission factor
B. Fugitive Emissions from Fuels	T1, T3	CS	T1,T2,T3	CS	T1	CS
1. Solid Fuels	-	-	T2,T3	CS	-	-
2a Oil	T1	CS	T1	CS	-	-
2b Gas	T1,T2	CS	T1,T2	CS	-	-
2c Oil and Gas venting and flaring	T1,T3	CS	T1, T3	CS	T1	CS

Notes: T1 = Tier 1. T2 = Tier2. T3 = Tier3. CS= Country-specific. D= IPCC default.

Data Sources

Principal data sources include Coal Services Pty Ltd, Queensland Department of Mines and Energy, coal mining companies (BHP Billiton and Anglo Coal), the Australian Petroleum Production and Exploration Association, the Australian Gas Association, the Energy Supply Association of Australia and the Australian Bureau of Agricultural and Resource Economics.

1B1a Solid Fuels: Coal Mining and Handling Activities

Introduction

Most coal seams contain CH_4 and sometimes other gases trapped within the interstices of the coal. When coal is mined, the seams are broken up and the gas escapes. This is the source of fugitive greenhouse gas emissions from the mining and handling of coal.

The amount of CH_4 released during coal mining depends on a number of factors, of which coal rank, seam depth and mining methods are generally the most important, though other factors such as moisture content may also have an effect. The degree of increase of coal rank determines the quantity of CH_4 generated within the seam. Once generated, the amount of CH_4 stored in the coal is largely controlled by depth of occurrence, the pressure of the gas and the temperature of the coal seam, although some other less well-defined characteristics of the coal can also play a role. If two coal seams have the same rank, the deeper lying seam will, in general, hold larger amounts of CH_4. Thus, high rank coals will emit more CH_4 than low rank coals and underground mining will typically generate more CH_4 than open cut mining.

The release of coal seam CH_4 into the confined spaces of underground coal mines presents an extreme safety hazard. Underground coal mines therefore have high capacity ventilation systems, which entrain and dilute the CH_4, and vent it to the atmosphere. In recent years CH_4 drainage systems have been installed at some of the most "gassy" mines. Such systems extract CH_4 from the coal seam in advance of mining through holes drilled into the coal seams. Gas released during mining is extracted through bore holes drilled from the surface into rock layers adjacent to the coal seam.

When the extracted CH_4 is not highly diluted with air, it may be suitable for use as a fuel for a variety of purposes. In most of the systems currently operating it is used to generate electricity. The CH_4 extracted and used in this way is included, appropriately adjusted for calorific value, in the natural gas consumption component of national energy statistics. Emissions arising from the combustion of this gas are accounted for in the *Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks 2006: Energy (Stationary Sources)*.

Most of Australia's resources and production of black coal are located in New South Wales and Queensland. There is also a very small quantity of bituminous black coal mined in Tasmania.

In Victoria, large quantities of brown coal are mined in open cut operations. The CH_4 content of this coal is extremely low. Sub-bituminous coal is mined in Western Australia and South Australia. In both States the coal is close to brown coal in its characteristics and CH_4 emissions are considered to be negligible.

Directly measured mine methane emissions, obtained from coal mining companies, are included for the majority of underground mines. For mines where measured data is not available, the estimation of emissions is based on grouping Australian mines into a small number of categories of broadly similar mines. Emission factors or, in some cases,

emission equations, have been developed for each mine category based on the available empirical data, ie actual measurements of emissions from representative mines in each category.

For inventory purposes, the coal industry is defined as comprising only two processes: mining and post-mining activities. The latter includes all transport, beneficiation, and other handling between the mine mouth and the point where the coal is either consumed or leaves Australia.

1.B.1ai Underground Mining

Mine methane concentrations within underground mines are monitored by mining companies as part of their operational procedures. Where available, mine emissions derived from direct measurement are included in the inventory. For mines where measured data is not available, an empirical approach is taken. Emissions from underground coal mining in Queensland and New South Wales in 1990 and 1994 respectively were estimated in Williams et al. (1992) and Williams, Lama and Saghafi (1996). Both reports divide mines into two groups, having significantly different levels of CH_4 emissions. The two groups are designated Class A ("gassy") and Class B ("non-gassy").

Measured Emissions from Underground Mines

Mine methane concentrations within underground mines are monitored by mining companies as part of their operational procedures. Where available, mine emissions derived from direct measurement are included in the inventory. Direct measurement now account for the majority of underground mine emissions. Where direct emission mine data have been obtained for later years only, then an emission factor is derived using the measured emissions and the corresponding mine production, with the emission factor then applied to the historical time series using the known mine production activity data.

Production Data

The production data for each mine in New South Wales comes from Coal Services Pty Ltd, while production data for coal mines in Queensland and Tasmania come from statistical publications produced by the Queensland Department of Mines and Energy and Mineral Resources Tasmania respectively.

Emissions from Underground Class A Mines

Emissions are estimated as the average of the results from the application of two empirical models. In the first study, analysis of data provided by individual mines on CH_4 concentrations in ventilation exhaust, ventilation flow rate, in-situ CH_4 concentration and coal production rate enabled the annual CH_4 release to be calculated for 24 Class A mines, which accounted for about three quarters of total Class A production. Statistical analysis of the data showed a correlation between CH_4 emissions, in-situ gas content of the coal and production for the mines where measurements were taken. The mathematical

form of the relationship between these values established by Williams et al. (1992) is given in algorithm (1B1_1):

$$E_{a1} = (4.95 \times QTY_a \times IN\text{-}SITU_{1990} + 5.58) \times C_a \qquad (1B1\_1)$$

Where E_{a1} is the total CH_4 emissions (**in Gg**) from Class A underground mines calculated using algorithm (1B1_1),
QTY_a is the annual quantity of raw black coal mined in class A underground mines (in Mt),
$IN\text{-}SITU_{1990}$ is the average coal seam methane content (in m^3/t) for Class A black coal mines in 1990 (see Table 2),
C_a is the volume-to-mass conversion factor (in kg/m^3) for Class A mine emissions (see Table 2), and
4.95 and *5.58* are constants.

Algorithm (1B1_1) expresses the relationship between raw coal production, in-situ gas content and mining CH_4 emissions for the entire *group* of Class A mines in Australia in 1990. It does not apply to any *specific* mine. The average in-situ gas content for all Class A mines in 1990 can be readily calculated with algorithm (1B1_1), from the total emissions and production tonnages reported by Williams et al. (1992). Adjustment has been made for the 43 Gg of extracted CH_4 used in mine-site electricity production in that year.

Williams, Lama and Saghafi (1996) repeated the analysis of emissions at the same group of mines in 1994, and again analysed the relationship between measured emissions, production and in-situ gas concentration. A different correlation was found, and this is shown in algorithm (1B1_2):

$$E_{a2} = (4.01 \times QTY_a \times IN\text{-}SITU_{1994}) \times C_a \qquad (1B1\_2)$$

Where E_{a2} is the total CH_4 emissions (**in Gg**) from Class A underground mines. calculated using algorithm (1B1_2),
QTY_a is the annual quantity of raw black coal mined in class A underground mines (in Mt),
$IN\text{-}SITU_{1994}$ is the average coal seam methane content (in m^3/t) for Class A black coal mines in 1994 (see Table 2),
C_a is the volume-to-mass conversion factor (in kg/m^3) for Class A mine emissions (see Table 2), and *4.01* is a constant.

These values, which are summarised in Table 2, give a value of 6.78 m^3/tonne for average in-situ gas content in 1990.

Table 2: CH_4 emissions per year from Class A underground mines, as measured by separate studies in 1990 and 1994

	1990	1994
Production (million tonnes raw coal)	33.8 *(a)*	33.8 *(b)*
Average in-situ CH_4 content (m^3/tonne)	6.78 *(c)*	3.40 *(d)*
Total CH_4 emissions (Gg)	703 *(a)*	461 *(e)*
Volume to mass conversion (kg CH_4/m^3)	0.616 *(f)*	0.616 *(g)*
Total CH_4 emissions (million m^3)	1141	748
CH_4 used for electricity (Gg)	43 *(a)*	43 *(b)*
Net CH_4 emissions (Gg)	660	419

(a) Williams et al. (1992).
(b) Williams, Lama and Saghafi (1996); note that Williams values for coal production and for CH_4 used in electricity are same in both years.
(c) Calculated using algorithm (1B1_1) and total Class A mine emissions for 1990 reported in Williams et al. (1992).
(d) Calculated using algorithm (1B1_2) and total Class A mine emissions for 1994 reported by Williams (pers. comm. 1996).
(e) Williams (pers. comm. 1996); a further 23 Gg was from post-mining emissions of coal from Class A mines, giving total of 484 Gg.
(f) Williams et al. (1992) and assuming a mine temperature of around 30° C.
(g) Williams, Lama and Saghafi (1996) actually uses a factor of 0.65 (Williams, pers. comm) although it does not enter the algorithm. If a factor of 0.616 is retained, differences due to the effects of other elements of the algorithm become apparent.

For typical levels of coal production, algorithm (1B1_2) gives about one third lower CH_4 emissions than does algorithm (1B1_1). The reasons for this difference include (i) changes in underground mining due to closures or decreased production from some gassy mines and the start-up of some new mines with less gas production, and (ii) accuracy of the data supplied. Williams, Lama and Saghafi (1996) advise that measurements of CH_4 concentrations are accurate to within 20%, as are values of in-situ gas content.

Estimated emissions are given as the average of the results of the application of the two approaches.

$$E_a = (E_{a1} + E_{a2}) / 2 \qquad (1B1\_3)$$

Where E_a is the total CH_4 emissions (in Gg) from Class A underground mines to be used in the inventory,
E_{a1} is the total CH_4 emissions (in Gg) from Class A underground mines calculated using algorithm (1B1_1), and
E_{a2} is the total CH_4 emissions (in Gg) from Class A underground mines calculated using algorithm (1B1_2).

Emissions from Underground Class B Mines

Similarly to Class A mines, measurements have also been made of emissions from Class B mines (Williams et al. 1992). The relationship established between coal production and CH_4 emissions from mining for the entire *group* of Class B mines in Australia in 1990 is described by algorithm (1B1_4). This study assumes that the CH_4 content of the air vented from Class B mines is 0.02 per cent by volume.

$$E_{b4} = (102 \times QTY_b + 88) \times 6307 \times C_a \times 10^{-6} \qquad (1B1\_4)$$

Where E_{b4} is the total CH_4 emissions (in Gg) from Class B underground mines, calculated using algorithm (1B1_4),
QTY_b is the annual quantity of raw black coal mined in Class B underground mines (in million tonnes),
C_a is the volume-to-mass conversion factor for Class B mine emissions (in kg/m^3). This is the same as for Class A mine emissions (see Table 2), and
102, 88 and *6307* are constants.

Williams, Lama and Saghafi (1996) repeated the analysis for the same group of mines with 1994 data, and established a considerably simpler relationship between raw coal production and CH_4 emissions from mining for Class B mines in Australia in 1994. This is shown in algorithm (1B1_5):

$$E_{b5} = 0.67 \times QTY_b \times C_a \qquad (1B1\_5)$$

Where E_{b5} is the total CH_4 emissions (in Gg) from Class B underground mines, calculated using algorithm 1B1_5,
QTY_b is the annual quantity of raw black coal mined in Class B underground mines (in million tonnes),
C_a is the volume-to-mass conversion factor for Class B mine emissions (in kg/m^3), and *0.67* is a constant.

For typical levels of coal production, algorithm (1B1_5) gives about two thirds higher CH_4 emissions than does algorithm (1B1_4).

As with Class A mines, the average of the value yielded by two algorithms (in this case (1B1_4) and (1B1_5)) is used to calculate the emissions in a specific year, and is expressed in algorithm (1B1_6):

$$E_b = (E_{b4} + E_{b5}) / 2 \qquad (1B1\_6)$$

Where E_b is the total CH_4 emissions (in Gg) from Class B underground mines to be used in the inventory,
E_{b4} is the total CH_4 emissions (in Gg) from Class B underground mines calculated using algorithm (1B1_4), and
E_{b5} is the total CH_4 emissions (in Gg) from Class B underground mines calculated using algorithm (1B1_5).

Total Emissions from Underground Mines

Total emissions of CH_4 from underground coal mines in Australia are estimated as the sum of emissions from Class A and Class B mines (as estimated using algorithms (1B1_3) and (1B1_6)) and measured mine emissions. A correction has to be made to allow for gas which is extracted from mines in advance of mining, and used as fuel at the mine site. Although this may occur at any mine, in practice it only occurs at Class A underground mines. Total emissions from underground mines are estimated by:

$$E_u = E\,m + (E_a + E_b - E_{ef}) \qquad (1B1\_7)$$

Where E_u is the total CH_4 emissions (in Gg) from underground mines,
E_m is the total CH_4 emissions (in Gg) from underground mines estimated from direct measurement
E_a is the total CH_4 emissions (in Gg) from Class A underground mines as estimated by algorithm (1B1_3),
E_b is the total CH_4 emissions (in Gg) from Class B underground mines as estimated by algorithm (1B1_6), and
E_{ef} is the total (in Gg) of extracted CH_4 used as fuel as reported by mine operators

1.B.1aii Surface Mining

Measurements have also been made of CH_4 emissions from open cut coal mines in New South Wales and Queensland (Williams et al. 1993). The experimental results were used to estimate emission factors (in m^3/tonne raw coal) applicable to open cut black coal mining in each State, and these are shown in Table 3.

Table 3: CH_4 emission factors for open cut black coal mining

Coal source	CH_4 emission factor E m^3/t raw coal mined	Volume-to-mass conversion factor kg/m^3 *(c)*
NSW	3.2 *(a)*	0.6767
Queensland	1.2 *(a)*	0.6767
Tasmania	1.0 *(b)*	0.6767

(a) Source: Williams et al. (1993) and confirmed by Australian Coal Association.
(b) Source: D Cain, Australian Coal Association, pers. comm. (1993) .
(c) These factors are derived by treating CH_4 as an ideal gas, ie 16 g (1 mole) occupies 23.645 l at 15 ^oC and 1 atmosphere.

Total emissions from open cut mines are then estimated by the following algorithm:

$$E_o = (QTY_{NSW} \times EF_{NSW} + QTY_{QLD} \times EF_{QLD} + QTY_{TAS} \times EF_{TAS}) \times C_{oc} \quad (1B1\_8)$$

Where E_o is the total amount of CH_4 (in Gg) emitted from open cut mining,
QTY_{NSW} is the quantity (in Mt) of open cut coal mined in New South Wales,
EF_{NSW} is the CH_4 emission factor (in m^3/t) for open cut coal mining in New South Wales,
QTY_{QLD} is the quantity (in Mt) of open cut coal mined in Queensland,
EF_{QLD} is the CH_4 emission factor (in m^3/t) for open cut coal mining in Queensland,
QTY_{TAS} is the quantity (in Mt) of open cut black coal mined in Tasmania,
EF_{TAS} is the CH_4 emission factor for open cut coal mining in Tasmania (in m^3/t), and
C_{oc} is the volume-to-mass conversion factor (in kg/m^3) for open cut mine emissions (see Table 3; same for all States).

Post Mining Activities

Williams et al. (1993) measured the amount of gas retained in coal from gassy underground (ie Class A) mines in NSW and Queensland, once the coal reached the surface. Most of this gas is likely to desorb from the coal before combustion - during preparation, transportation, storage or crushing - and can therefore be classified as fugitive emissions from post mining activities. Williams et al. (1993) found that the amount of gas retained was quite variable, but adopted an average gas emission factor of 1.7 m^3/t raw coal, of which 75% is CH_4 and 25% CO_2. The volume-to-mass conversion factor is 0.6767 kg/m3.

Emissions from post mining activities based on the measurements of Williams et al. (1993) are estimated using the following algorithm:

$$E_{pm9} = QTY_a \times EF_{pm} \times C_{pm} \quad (1B1\_9)$$

Where E_{pm9} is the total amount of CH_4 emissions (in Gg) from post mining activities involving Class A black coal calculated using algorithm (1B1_9),
QTY_a is the quantity (in Mt) of underground Class A black coal.
EF_{pm} is the emission factor (in m^3/t) for post mining activities using Class A coal, which equals 1.7 x 0.75 = 1.275 m^3/t raw coal (see above), and
C_{pm} is the volume-to-mass conversion factor for post mine emissions, which equals 0.6767 in kg/m^3 (see above).

A simpler relationship between emissions and in-situ CH_4 concentrations was developed by Williams, Lama and Saghafi (1996) from measurements made in 1994. This relationship is used in the following algorithm:

$$E_{pm10} = (0.2 \times QTY_a \times IN\text{-}SITU_{1994} \times C_{pm}) \quad (1B1\_10)$$

Where E_{pm10} is the total amount of CH_4 emissions (in Gg) from post mining activities involving Class A black coal, calculated using algorithm (1B1_10),
QTY_a is the annual quantity of raw black coal mined in Class A underground mines (in Mt),
$IN\text{-}SITU_{1994}$ is the average coal seam methane content (in m^3/t) for Class A black coal mines in 1994 (see Table 1), and
0.2 is a constant.
C_{pm} is the volume-to-mass conversion factor for post mine emissions, which equals 0.6767 in kg/m^3 (see above).

As with the estimation of emissions from mining Class A black coal, the preferred estimate for post-mining emissions is made by averaging the values obtained using the two different methods. This is expressed in the following algorithm:

$$E_{pm} = (E_{pm9} + E_{pm10})/2 \quad (1B1\_11)$$

Where E_{pm} is the total post-mining CH_4 emissions (in Gg) to be used in the inventory,
E_{pm9} is the total post-mining CH_4 emissions (in Gg) calculated using algorithm (9), and
E_{pm10} is the total post-mining CH_4 emissions (in Gg) calculated using algorithm (1B1_10).

It is assumed that post mining emissions are associated only with black coal mined in underground Class A (gassy) mines, and not with black coal mined in underground Class B mines, or with brown coal.

Total Emissions from Coal Mining

Total emissions from coal mining in Australia are estimated by summing emissions from underground black coal mining, open cut black coal mining and post-mining activities. This is expressed by the following algorithm:

$$E_{cm} = E_u + E_o + E_{pm} \qquad (1B1\_12)$$

Where E_{cm} is the total CH_4 emissions (in Gg) from black coal mining,
E_u is the total CH_4 emissions (in Gg) from underground black coal mining as estimated using algorithm (1B1_7),
E_o is the total CH_4 emissions (in Gg) from open cut black coal mining as estimated using algorithm (1B1_8), and
E_{pm} is the total CH_4 emissions (in Gg) from post-mining activities.

1.B.1.c Decommissioned mine emissions

The mining and post mining handling of coal are recognised by the UNFCCC as sources of methane emissions. Emissions arising from these activities are reported in Australia's National Greenhouse Gas Inventory using methodologies consistent with IPCC/UNFCCC reporting guidelines. Methane emissions are also known to occur under certain conditions following closure/abandonment of coal mines - leaking to the atmosphere through fractured rock strata, open vents and seals over daily to decades timescales.

Methodology

The Australian methodology is based on the approach developed in the 2006 IPCC Guidelines for National Greenhouse Gas Inventories. The decline of emissions following mine closure are modelled using emission decay curves (EDCs) for dry, gassy and non-gassy mines. In addition, the EDCs are adjusted on a mine-by-mine basis according to the flooding characteristics of each mine.

Key data required for the approach include:

- Mine closure history
- Emissions at time of closure
- Dry mine EDCs for gassy and non-gassy Australian mines
- Mine void size
- Mine water inflow rates

The approach seeks to maximise the use of publicly available data, and is best described as a high tier 2/3 approach. It is consistent with a Tier 3 approach in that it estimates emissions on an individual mine basis. However, other mine-specific data characteristic of higher level Tier 3 approach are absent, such as characteristics of the mined coal seam, permeability and direct measured emissions.

The EDC methodology used for estimating methane emissions from decommissioned mines can be described as:

$$E_{dm} = (E_{tdm} \times EF_{dm} \times F_{dm}) - E_{rec} \qquad (1B1\_12)$$

Where E_{dm} is the emissions (Gg methane/year) for a mine at a particular point in time.
E_{tdm} is the annual emission rate of the mine at point of decommissioning (Gg methane/year)
EF_{dm} is the emission factor for a mine at a point in time since decommissioning. It is derived from the EDC (formulae 1B1_13 & _14). The emission factor is dimensionless
F_{dm} is the fraction of mine flooded at a point in time since decommissioning.
E_{rec} is the quantity of methane emissions avoided by recovery.

Emission decay curves

An emission decay curve (EDC) describes the decline in fugitive methane emissions over time following mine closure. Hyperbolic curves have been found to function best in portraying the rapid decline in emissions in first few years, followed by a slow decline over time of the remaining emissions.

Australian-specific EDCs were utilised for gassy and non-gassy mines respectively. The EDCs represent the dry mine case and have been developed from studies of long term (1982 -2006) direct gas emission measurements from Australian mines Lunarzewski (2005), Armstrong, Lunarzewski & Creedy (2006). The EDCs are shown in Figure 1, and are described in the following formulae:

Gassy mines

$$EF_{dm} = (1 + \mathbf{A} * \mathbf{T})^{b} - C \qquad (1B1\_13)$$

Non-gassy mines

$$EF_{dm} = (1 + \mathbf{A} * \mathbf{T})^{b} - C \qquad (1B1\_14)$$

Where EF_{dm} is the emission factor for a mine at any point in time since decommissioning. The emission factor is dimensionless

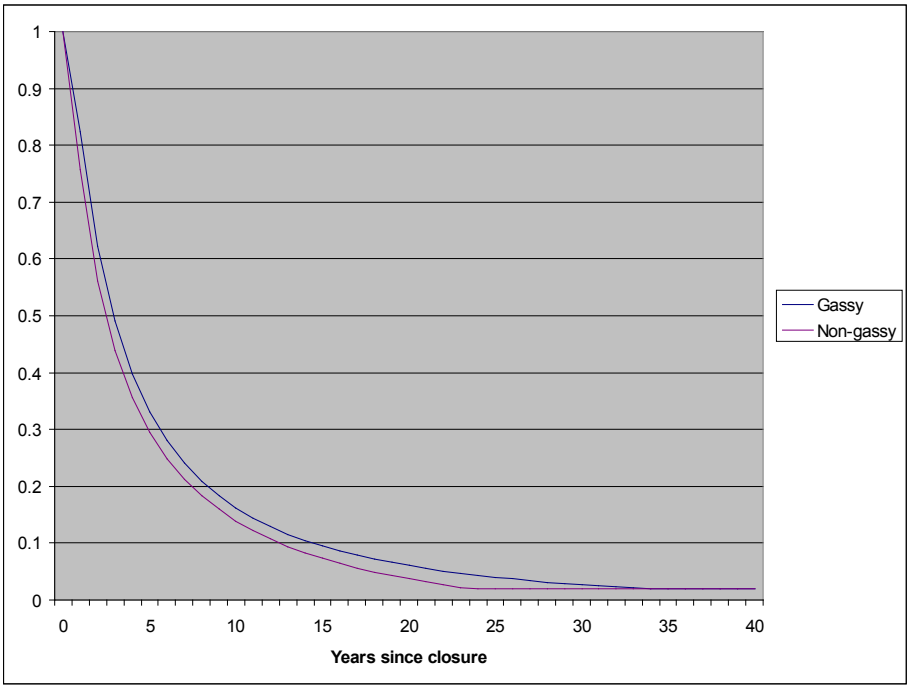
T is the time elapsed since decommissioning of mine.

A, b and c are coefficients unique to the decline curve (see table below):

Table 4: Coefficients used in Australian EDCs

Mine category	Coefficients		
	A	b	C
Gassy Mines	0.23	-1.45	0.0242
Non-Gassy mines	0.35	-1.01	0.0881

Figure 1. Emission decline curve for gassy and non-gassy Australian decommissioned coal mines.



Mine production data

Mine production data are obtained from:

- Coal Services Pty Ltd (formerly the Joint Coal Board) for NSW mines from 1972, and
- Queensland Department of Natural Resources, Mines and Energy, from 1979.

In both datasets, details were obtained for mine type (underground/open cut), annual run-of-mine production and time of closure. Only underground mines were included in the study. Open cut mines were not included in the study as they are associated with relatively low methane emissions. This approach is consistent with the 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

A total of 117 Underground mine closures (Class A-gassy and B-non gassy) back to 1972 were identified, with 97 mines back to 1979.

Emissions at closure

In order to estimate the decline of emissions over time following closure, it is first necessary to establish emissions at year zero, that is, emissions at the point prior to closure. The approach used is consistent with that used to estimate methane emissions from active underground coal mines (see 1.B.1ai). Final mine production at closure is taken as the last full year of production.

Decommissioned mines are defined as Class A (gassy) or Class B (non-gassy) based on

existing classifications used to calculate previous National Greenhouse Gas Inventories. For earlier mines, for which class tends to be unknown, mines were classified according to their geological proximity to other mines for which class was known.

Adjustment of EDC for flooding mines

It is common for decommissioned mines to become flooded over time. The flooding of mines is known to result in a very rapid decline in the release of methane, thus having a substantial impact on the shape of the ECD, and on overall emissions.

The approach uses emission values calculated using dry mine EDCs (formulae 1B1_13 & _14), and makes adjustments based on the proportion of the mine flooded at that time. For example, if a mine is 50% flooded 10 years post closure then the emission value derived from the EDC is adjusted at that point in time by 50%.

Determining the mine flooding rate:
The following information is required in order to estimate the flooding rate of any particular mine:

- Size of the mine void volume
- Rates of mine water inflow.

- Estimating mine void volume

The quantity of run-of-mine coal production removed from the mine is used as a basis for estimating the mine void volume remaining at the time of closure. Total historical mine ROM coal production is converted from tonnes to cubic metres by multiplying the total tonnage by 1.425, representing the specific gravity of an average Australian worked coal seam and allowing for the presence of non-coal seam voids within mines Lunarzewski (2006).

- Mine water inflow rate estimation

Mine water production data are difficult to obtain on a mine by mine basis, particularly for older, decommissioned mines. The approach taken is to develop a set of basin/ state average mine water inflow rates based on available data.

The primary source of mine water production rates for individual mines were obtained from publicly available Environmental Impact Statements (EIS) for mining development projects. EIS provides a good coverage of ground water hydrology, providing data on mine water production rates for proposed mines, extensions, nearby existing mines and the flooding status of surrounding mines.

Water production rates for three regions were then calculated. The Southern NSW region contained mine water production rates ranging between 1 – 5.0 ML/Day and an average value of 2.5ML/day. The Central NSW region ranged between 0.4 and 3ML/Day and an average value of 1.2ML/Day and Queensland ranged between 0.1 and 0.4ML/Day and an average value of 0.2ML/Day.

Assumptions
The following assumptions were necessary in estimating mine water inflow rates:

1. The mine floods at a linear rate.
2. Mine water production is the same for each mine on a basin/state scale
3. Methane is produced evenly throughout the mine and flooding reduces the emissions proportionately to the void volume flooded

Fully Flooded Mine Emissions

Once a goaf area has been fully flooded, the associated primary gas sources can no longer release gas into the workings, however, remaining free gas in the strata and desorbing gas from unflooded secondary gas sources could continue to leak to the atmosphere (ground surface) via fractured rock strata i.e. geological faults, cracks and fissures (structurally induced pathways). A constant of 2% of the emissions at the time of mine closure has been adopted to represent emissions once fully flooded Lunarzewski (2006).

Mine seal Status

The sealing status of mines, ie the proportion to which the mine is sealed, are also known to influence the EDC. Seals are generally acknowledged to leak over time, although they can alter the emission flow rate within the early years following closure. Modelling of EDCs for varying sealing regimes by the US show little difference in emission rates between 95% sealed and 50% sealed mines one year after closure. Consequently no data have been obtained on the sealing status of Australian mines and it has been assumed that all mines were unsealed.

1.B.2 Oil and Natural Gas Activities

The IPCC guidelines define a two level hierarchical structure for source categories related to the oil and gas industries. At the top level of the hierarchy are:

- emissions related to oil (1B2a),
- emissions relating to gas (1B2b), and
- venting and flaring emissions relating to both oil and gas (1B2c).

The main emission sources included in the first two categories are leakage, evaporation and accidental releases, ie uncontrolled sources. Emissions from venting and flaring are activities that are managed as part of normal operations at field processing facilities and oil refineries. Each of these three major categories is in turn divided into several sub-categories.

Venting and flaring emissions occur at several stages of the oil and gas production process. The structure of the categories means that a single process can contribute greenhouse gas emissions to two or more categories of emissions.

Comprehensive data is obtained from the Australian Petroleum Production and Exploration Association (APPEA), which publishes data on industry emissions in the form of a public annual inventory report to the Greenhouse Challenge Plus Program. The data is collected by means of a survey of industry companies. PricewaterhouseCoopers and KPMG have independently verified APPEA's inventories through the Greenhouse Challenge Program.

Emissions factors used in the APPEA sourced emission data are derived from "Methods of Estimating Atmospheric Emissions from E and P Operations" (E and P Forum 1994) (see Appendix B.2). An exception is the emission factor for Natural Gas Production and Processing which is based on throughput sourced from an average of APPEA member companies data, giving a better representation of the conditions of the Australian industry.

Emissions from Venting – Natural Gas are based on direct measurement company data as reported by APPEA.

The National Greenhouse Gas Inventory sources emission data for certain sub-categories within Oil and Natural Gas activities, as well for Venting/Flaring from the APPEA publication. Those Inventory subcategories, and the corresponding relationship with APPEA source categories are shown in Table 5.

Table 5: Relationship between NGGI and APPEA source sub-categories

NGGI sub-category		APPEA sub-category
Oil	Exploration (for both oil and gas)	Production Testing—Gas Flared —Oil Flared
	Crude oil production	**Internal Floating tank** **Fixed roof tank** **Floating tank**
Natural gas	Production and processing	Fugitive Emissions
Venting and Flaring	Venting	Gas Venting
	Flaring	Flares

1.B.2a Oil

1.B.2ai Oil (and Gas) Exploration

Emissions may occur during the process of drilling for oil and gas either during exploration or development drilling, whenever gas or liquid hydrocarbons are encountered. If a well is production tested and permanent facilities are not connected, CO_2, some unburnt CH_4 and NMVOCs are released as a result of the flaring of oil or the flaring or venting of gas. Emissions of CH_4 and NMVOCs may also occur as a result of leakages and accidental releases such as blowouts.

In Australia, most onshore exploration wells are drilled to delineate new reserves in established gas fields or in the expectation of discovering new gas fields rather than the expectation of finding oil. Therefore in Australia's inventory, oil and gas exploration emissions are treated as a single category, which should be seen as related to subsequent production and consumption of both oil and gas.

During production testing of a discovery well, gas and liquid hydrocarbons are allowed to pass at a controlled pressure through a flow meter. Tests typically run for about 24 hours and, in earlier years, standard practice was to flare all this material. APPEA advises that as onshore Australian oil and gas fields become mature it is becoming increasingly common for test gas to be run through a temporary pipe to the nearest field gathering line, while test liquids from onshore wells are collected and transferred to a road tanker for subsequent sale. Consequently, although the rate of discovery has remained roughly constant, the volume of oil and gas flared has tended to decrease, and this trend is expected to continue.

Emissions are based on those reported in the APPEA greenhouse gas emission inventory. Relevant emission factors are sourced from the E and P Forum (1994).

1.B.2aii Crude Oil Production (other than venting and flaring)

Emissions of CH_4 and NMVOCs may occur during oil production, including field processing, as a result of:

- leakages at seals in flanges, valves, and other components in a variety of process equipment;
- accidental events;
- storage tanks and venting of gases during oil production
- controlled releases of pressurised pipe and component contents (blowdown) during routine maintenance activities, including well workovers, pipeline testing, process equipment maintenance etc.

All other things being equal, emissions will tend to be greater from fields with a higher solution gas/oil ratio than from fields with a low solution gas/oil ratio. Emissions of CH_4 and NMVOCs may also occur while crude oil is in storage at production facilities, awaiting transportation, if vapour recovery is not employed.

Emissions are reported directly from the APPEA greenhouse gas emission inventory, corresponding to the subcategories - Loading losses plus Fugitive Emissions: tank losses (all categories except general leaks). Emission factors used for the APPEA inventory can be found in Appendix B, and are based on the E and P Forum (1994).

1.B.2aiii Crude Oil Transport

The marine (or road/rail) transport of crude oil results in the emissions of NMVOCs, CH_4 and dissolved CO_2. The extent of emissions depends on the gas control technology employed during transfer operations, fuel properties, eg vapour pressure and gas composition, ambient temperatures, trip duration and the leak integrity of tanks.

Emissions associated with the marine transport of crude oil are of three types: loading, transit, and ballasting. Loading losses occur when organic vapours in the cargo tanks are displaced by liquids being loaded. These vapours are vented to the atmosphere or to a vapour recovery system. Transit losses occur during transport as a result of leaking seals or safety related venting of vapours. Ballasting losses may occur after the unloading of oil as cargo tank compartments are filled with seawater (called ballast). Marine vessels having segregated ballast systems should not emit hydrocarbons during reballasting.

In the absence of local data, IPCC guidelines (1997, Volume 3) recommend the use of USEPA CH_4 emission factors for crude oil transport. From the use of USEPA data, it is estimated that 745 kg CH_4 is emitted per PJ of oil tankered (IPCC, 1997, Volume 3). Given the similarities in fuel transfer regulations between the USA and Australia, the US emission factor is adopted in this workbook.

Data for NMVOCs and CO_2 emissions from crude oil transport are not available from IPCC. Using the USEPA finding that CH_4 makes up 15% of the mass of total organic emissions (USEPA, 1995), the NMVOC emission factor for marine transport is estimated to be 4,200 kg per PJ of oil tankered.

Use of emission factors in the above form carries the implicit assumption that the CH_4 content of crude oil vapour is constant during transport. In reality, the CH_4 content of crude oil is strongly dependent on the transport and storage history in addition to the original CH_4 content of the oil. The crude oil from production facilities contains relatively high amounts of gaseous CH_4 in solution. As the oil progresses through the storage and transportation system, the CH_4 content decreases.

Three emission estimates are reported, indigenous crude oil used within Australia, exported crude oil and imported crude oil. Fugitive emissions from the cargoes of ships engaged in international trade are a component of international bunker fuels, which are excluded from national inventories.

The volume of indigenous crude oil transported by ship to Australian refineries is assumed to equal indigenous crude oil production, minus crude oil exports, minus petroleum product consumption in Victoria (where the great majority of the crude oil processed at

Victorian refineries is transported via pipeline from the Bass Strait oil fields). Bass Strait oil is transported to other Australian refineries by ship, as is most of the oil from other Australian oil fields used by Australian refineries.

Emissions of CH_4 and NMVOCs from the shipment of indigenous crude oil to Australian refineries may be calculated according to:

$$E_{cot} = EF_{cot} \times (QTY_{in} - QTY_{ex} - QTY_{vic}) / 10^6 \quad (1B2\_1)$$

Emissions of CH_4 and NMVOCs from the export of crude oil from Australia may be calculated according to:

$$E_{coe} = EF_{cot} \times QTY_{ex} / 10^6 \quad (1B1\_2)$$

Emissions of CH_4 and NMVOCs from the import of crude oil to Australia may be calculated according to:

$$E_{coi} = EF_{cot} \times QTY_{im} / 10^6 \quad (1B1\_3)$$

Where E_{cot} is the total emission of CH_4 or NMVOCs from the transport of indigenous crude oil to Australian refineries in Gg/yr of oil tinkered,
E_{coe} is the total emission of CH_4 or NMVOCs from the export of crude oil from Australia in Gg/yr of oil exported,
E_{coi} is the total emission of CH_4 or NMVOCs from the import of crude oil to Australia in Gg/yr of oil imported,
EF_{cot} is the emission factor for CH_4 (745 kg/PJ) or NMVOCs (4,200 kg/PJ) from the transport of crude oil in kg/PJ of oil tinkered,
QTY_{in} is total indigenous crude oil production in PJ/yr,
QTY_{ex} is the amount of crude oil exported in PJ/yr,
QTY_{vic} is the amount of petroleum products consumed in Victoria in PJ/yr, and
QTY_{im} is the amount of crude oil imported in PJ/yr.

1.B.2aiv Crude Oil Refining and Storage

Crude oil is refined to numerous products via a wide variety of physical and chemical processes. During such processing, fugitive emissions of NMVOCs and CH_4 are generated. Fugitive emission sources at crude oil refineries include valves, flanges, pump and compressor seals, process drains, cooling towers, and oil/water separators.

Crude oil is stored at pipeline pump stations and refineries. During such storage, NMVOCs and CH_4 are emitted from normal processes such as tank breathing, and working and standing losses. Breathing losses involve the expulsion of vapour from fixed roof tanks by the activation of pressure relief valves as vapour expands and contracts in response

to temperature and pressure fluctuations. Working losses result from tank-filling operations as hydrocarbon vapours are displaced from the tank with rising liquid level. Working losses can be substantially controlled (90% or better) by directing the displaced tank vapour to an external vapour recovery system. Standing storage losses apply to floating roof tanks and result from leaking seals and fittings. Flares are commonly used at refineries for the disposal of vented waste gases. The flaring of refinery gases results in the emission of CO_2, CH_4, N_2O and products of incomplete combustion.

Storage or tank losses are a complex function of a number of variables including tank characteristics, fuel properties, meteorological conditions, vapour emission control, and liquid throughput. In principle, engineering calculations may be conducted on individual tanks using available formulae (USEPA, 1995). In the absence of data at the individual refinery level, national CH_4 emissions from crude oil refining and storage may be calculated using default emission factors according to IPCC guidelines (1997). The mid range IPCC default emission factors are adopted for crude oil refining and storage, ie 745 kg/PJ for refining and 140 kg/PJ for storage.

Emissions of CH_4 from crude oil refining and storage may be calculated according to the following algorithm:

$$E_{ors} = (EF_{ref} + EF_{st}) \times QTY_{co} / 10^6 \qquad (1B2\_4)$$

Where E_{ors} is the total fugitive emission of CH_4 from the refining and storage of crude oil (in Gg),
EF_{ref} is the emission factor for CH_4 from the refining of crude oil (in kg/PJ of oil refined),
EF_{st} is the emission factor for CH_4 from the storage of crude oil (in kg/PJ of oil refined), and
QTY_{co} is the amount of crude oil refined (in PJ).

The emission factors to be used are: 745 kg/PJ for refining
140 kg/PJ for storage

Fugitive emissions of NMVOCs resulting from crude oil refining and storage have been estimated for Victoria (Environment Protection Authority Victoria, 1991). Based on the Victorian data it is estimated that the NMVOC emission factor associated with fugitive and tank storage/loading is 20,000 kg/PJ of oil refined.

Emissions of NMVOCs from crude oil refining and the storage of crude oil and refined petroleum products (on site) may be calculated according to the following algorithm:

$$E_{ort} = EF_{rs} \times QTY_{co} / 10^6 \qquad (1B2\_5)$$

Where E_{ort} is the total fugitive emission of NMVOCs from the refining of crude oil and storage of crude oil and refined petroleum products (in Gg),

EF_{rs} is the emission factor for NMVOCs from the refining and storage of crude oil, 20,000 kg/PJ of oil refined, and
QTY_{co} is the amount of crude oil refined (in PJ).

Oil refinery flaring

The composition of refinery flare feed-gas is highly variable and depends on plant processing, process upsets and flare operation. In this workbook the composition of refinery gas directed to flares is assumed to be 30% CH_4, 30% NMVOCs and 40% H_2 (by volume). An average flare combustion efficiency of 98% is used based on studies by USEPA (1995).

In previous years, information on the quantity of gas flared at Australian refineries has been determined using the single national figure provided in the national energy consumption statistics (ABARE). The methodology has been reviewed by GHD (2006) and the quantity of gas flared is now calculated as a 0.6 percent of the total ABARE annual refinery feedstock. The review considered the range and age of technologies of the Australian refining industry, and publicly available information on annual flaring emissions from Australian facilities, 0.6 percent of the total refinery throughput is considered a reasonable estimate of the range and age of technologies within the Australian industry.

E&P Forum (1994) has reported a methodology for estimating emissions of greenhouse gases from oil and gas exploration and production processes. This methodology allows emission factors for each greenhouse gas emitted to be calculated in kg per tonne of gas flared, provided that the composition of the flare gas stream is known; it can readily be adapted for application to refinery flaring. Further adaptation of the methodology, using the gross calorific values of each flare gas component, is required to express emission factors for all greenhouse gases in Gg/PJ of energy flared. Both sets of emission factors are shown in Table 6.

Table 6: Emission factors for flaring of gas at oil refineries

Unit	CO_2	CH_4	N_2O	NO_x	CO	NMVOCs
kg/t gas flared	2,695	6.8	0.081	1.5	8.7	12
Gg/PJ energy flared	47.2	0.12	0.0014	0.026	0.15	0.21

Source: Calculated as described in text, following methodology of E&P Forum (1994)

The emission of greenhouse gases from flaring operations at oil refineries may be estimated according to:

$$E_{fi} = QTY_{fi} \times EF_{fi} \qquad (1B2\_6)$$

Where E_{fi} is the total emission of gas *i* from the flaring of gas at oil refineries (in Gg/yr),
QTY_{fi} is the amount of gas flared (in PJ),
EF_{fi} is the emission factor for gas i per unit of gas flared (in Gg/PJ).

1.B.2av Petroleum Product Distribution

The distribution of petroleum products represents a significant source of fugitive NMVOC emissions. Emission sources include motor vehicle refuelling, service station tank filling and breathing losses, major fuel-terminal storage and tank filling losses and refuelling of aircraft and other mobile sources.

Emission factors for fuel storage tanks are a complex function of a number of variables. These emission factors are calculated from a weighted average analysis of fuel transfer and storage regulations in different regions of Australia (see Appendix B).

Table 7: NMVOC emission factors for petroleum product distribution (kg/kl distributed)

Emission Source	Emission factor (kg/kl distributed)		
	Petrol	Diesel	Avgas
Motor vehicle/equipment refuelling	1.40[(a)]	0.084[(b)]	N/A
Service station/premises, storage/transfer	0.66[(c)]	0.006[(d)]	N/A
Bulk fuel terminal, storage/transfer	1.08[(c)]	0.009[(d)]	N/AV
Aircraft, refuelling/storage	N/A	N/A	2.69[(e)]
Total all sources	3.14	0.099	2.69

Sources:
(a). USEPA (1995) Uncontrolled refuelling and spillage.
(b). USEPA (1992) Uncontrolled refuelling and spillage.
(c). See Appendix B.
(d). Scaled according to ratio of diesel/petrol emission rate for tank breathing and emptying as reported in USEPA (1992).
(e). Australian Environment Council (1988).

A number of assumptions were made in compiling these emission factors. Emissions from refined petroleum products in storage and in transit are assumed to be negligible, meaning that all emissions are associated with transfer and fuelling operations. Emissions associated with the normal distribution of LPG are also assumed to be negligible (Environment Protection Authority Victoria 1991; Environment Protection Authority NSW 1995). From a consideration of emission factors (USEPA, 1992) and the predominant modes of distribution of avtur and fuel oil, emissions of NMVOCs from the distribution of these fuels are estimated to be negligible.

The factors in Table 7 are applied to the sales volumes of each product distributed in Australia.

Emissions of NMVOCs from the distribution of petroleum products may be calculated according to:

$$E_{ppd} = \Sigma\, (EF_i \times QTY_i) / 10^3 \qquad (1B2\_7)$$

Where E_{ppd} is the total fugitive emission of NMVOCs from the distribution of petroleum products in Gg,
EF_i is the emission factor (kg/kl of product sold) for NMVOCs from the distribution of fuel i (i=1 petrol, i=2 diesel, and i=3 avgas), and
QTY_i is the amount of product i sold in Ml.

1.B.2B Natural Gas

1.B.2Bi Natural Gas Production and Processing (other than venting and flaring)

Emissions of CH_4 and NMVOCs may occur during natural gas production, including both production and field processing, from the same causes as the corresponding emissions from crude oil production, ie leakage, accidents and controlled releases for safety purposes and during some maintenance operations. In the case of natural gas, field processing is typically a considerably more complex process than in the case of crude oil production. Natural gas processing includes some of the same types of processes which, in the case of oil, occur at the refinery, eg separation into product streams, such as ethane, LPG and condensate, and removal of undesirable components of the raw gas stream, such as CO_2 and sulphur compounds.

Liquefaction of natural gas for export, which takes place at the North West Shelf liquefied natural gas (LNG) plant near Dampier in Western Australia, is more complex again; this is one of the largest process plants in Australia.

Venting of CO_2 extracted from raw gas and flaring of unusable gas produced at various stages of processing are separately accounted for under venting and flaring.

Other than at the Dampier LNG plant, storage and loading are not activities which occur with natural gas, since the gas moves directly from the processing facility into the transmission pipeline. Some losses of CH_4 may occur in association with the loading of LNG onto ships.

Emissions are reported directly by APPEA, corresponding to the subcategory - Fugitive Emissions; General Leaks. Emission factors used for the APPEA inventory can be found in Appendix B. In the case of Natural Gas Production and Processing, emission factors are derived by APPEA, based on company data averages.

1.B.2Bii Natural Gas Transmission and Distribution

Natural gas transmission

Australia has an extensive system of long distance natural gas transmission pipelines. For the purposes of this methodology, transmission mains are defined as high pressure pipelines > 1050 kPa, as used the Energy Supply Association of Australia natural gas statistics. As with oil and gas production, emissions may occur as a result of compressor starts (for which gas expansion is typically used to start gas turbine power units), blowdowns for maintenance at compressor stations, maintenance on pipelines, leakage and accidents.

The Australian high pressure gas transmission system is of relatively recent vintage (the oldest line dates from 1969), has been built to high quality standards and is well maintained. This is evidenced by the extreme rarity of accidental releases. Most lines

are built with isolating valves at intervals of 30 km or less along the line, so that in the event of a line rupture, the total quantity of gas released will be relatively small. In recent years, operating and maintenance practice has been modified so that blowing down of compressor stations occurs only when absolutely necessary, for operational or safety reasons. Routine monitoring of CH_4 concentrations in compressor station buildings, which is performed for safety reasons, consistently records extremely low concentrations (R. Calvert pers. comm.). For these reasons, it is assumed that leakage and accidental releases from gas transmission are zero.

Work undertaken by the Pipeline Authority (the organisation formerly responsible for operation of the Moomba to Sydney pipeline) concluded that losses from a typical gas transmission pipeline in Australia are 0.005% of throughput.

The factor of 0.005% and the throughput data are used in conjunction with national average pipeline gas composition figures, as given in Appendix C. Throughput data are obtained from the Australian Gas Association (AGA). AGA member companies supply 89% of all gas issued from the high pressure transmission pipelines. Therefore emissions are scaled up by dividing by 0.89.

For the reference year, fugitive emissions from the gas transmission system are estimated by:

$$E_i = EF_{trans} \times C_i \times VOL / 0.89 \qquad (1B2\_8)$$

Where E_i is the total fugitive emission of greenhouse gas i from the national gas transmission system (in Gg),
EF_{trans} is equal to 0.00005, and
C_i is the national average natural gas composition factor for gas i (in Gg/PJ) from Appendix C,
VOL is the total volume of natural gas consumed in the inventory year (in PJ), net of natural gas used in the Oil and Gas Mining sector of the economy, and
0.89 is a scaling factor to adjust for AGA data covering 89% of all gas issued from high pressure transmission pipelines in Australia.

IPCC Good Practice Guidelines (2000) recommend an approach where emissions are also linked to the length of pipeline rather than solely using throughput. Consistent with this approach, emissions are calculated using algorithm (1B2_8) for a reference year and emissions for other years scaled against the reference year according to the change in pipeline length. Pipeline length data are sourced from the Energy Supply Association of Australia (ESAA) series *Electricity Gas Australia.*

Natural gas distribution

The boundary between natural gas transmission and distribution is generally taken to be the city gate regulator stations at which gas pressures are reduced from transmission pressures (up to about 15 MPa) to sub-transmission pressures. According to Hutchinson et al. (1993), the major natural gas utilities in Australia use

the following classifications:

- trunk mains operating at pressures up to about 7 MPa,
- high pressure mains operating at pressures up to about 1.5 MPa,
- medium pressure mains operating at pressures up to about 0.2 MPa (200 kPa),
- low pressure network operating at pressures up to 7 kPa.

For the purposes of this methodology, natural gas distribution is defined as low, medium and high pressure reticulation ≤ 1050 kPa (as used the Energy Supply Association of Australia natural gas statistics).

Most of the gas lost from gas transmissions and distribution systems is by way of leakage from the low-pressure network. The amount of leakage depends on the number and condition of joints in the pipes. The high pressure and trunk main pipes are welded steel, so flanged joints are typically only at valves and compressors. Pressures are so high that any major leaks that might occur are obvious, dangerous and quickly attended.

According to Hutchinson et al. (1993), other causes of fugitive emissions from gas distribution systems (up to and including customer meter) are:

- third party damage (eg excavators),
- purging of new mains,
- unburnt gas from gas compressors (if there are any on the distribution system),
- gas lost to atmosphere on start up and shut down of compressors,
- regulating and relief valves.

There are no Australian data on fugitive emissions from the customer side of the meter, but these may arise from such sources as:

- leaking lines at fittings,
- purging of lines during appliance installation and maintenance,
- leaking appliance valves,
- extinguished pilot lights without automatic cut-off; and
- leakage when intermittently operated appliances (eg cookers) are ignited and extinguished.

Emissions from the distributor side of the meter are not measured directly, but must be based on estimates of unaccounted for gas (UAG). Components of UAG include: leakage emissions, meter inaccuracies, use of gas within the system itself, theft of gas, variations in temperature and pressure and differences between billing cycles and accounting procedures between companies delivering and receiving the gas.

The ratio of emissions to UAG for Australian utilities has been estimated at 80% (Dixon 1990) and 70-80% (Hutchinson et al. 1993). A leakage component for UAG of 90% was used in the Australian Methodology for the Estimation of Greenhouse Gas Emissions and Sinks, Energy, Workbook for Fugitive Fuel Emissions (Fuel Production, Transmission, Storage and Distribution), National Greenhouse Gas Inventory Committee, Workbooks 2.0 (1994) and 2.1 (1998). The ratio adopted of 90% made some allowance for the additional emissions from the customers' side of the meter, which were not covered in the two studies.

The progressive upgrade of the gas distribution infrastructure in response to a variety of drivers, including greenhouse gas emissions concerns, necessitated a review of the 90% UAG ratio in 2004. An analysis of industry data concluded that a figure in the range of 50-60% is a more realistic for current circumstances. Accordingly, the new estimate for leakage under UAG adopts a figure of 55% from 2003 onwards.

The previous value of 0.90 was introduced in the methodology developed to compile the NGGI for all years up to and including 1994. The transition to the value of 0.55 to apply from 2003 has been ramped in on a linear basis starting with the NGGI for 1995, i.e. in equal decrements of 0.35/9 for each of the nine years from 1995 to 2003 inclusive. This approach reflects the progressive upgrade of the gas distribution infrastructure.

The data sources necessary to calculate emissions from natural gas distribution are:

- estimates of UAG as a percentage of gas issued annually by gas utilities in each State, published in the ESAA series *Electricity Gas Australia.*
- annual gas utility sales in each State and Territory, published in the ESAA series *Electricity Gas Australia*; this figure is sales through the low pressure distribution system, and excludes sales made through high pressure mains to electricity generators and large industrial customers, and
- the composition of pipeline gas supplied in each State and Territory pipeline system, published in the AGA series *Gas Industry Statistics*, and shown in Appendix C.

Total UAG in each state is calculated by use of the following algorithm:

$$UAG_p = (S_p / (1- \%UAG_p/100)) - S_p \qquad (1B2\_9)$$

Where UAG_p is the total unaccounted for gas in State pipeline system p (in PJ),
S_p is the total gas utility sales from State pipeline system p (in PJ),
$\%UAG_p$ is the percentage of gas issued annually by gas utilities in that State pipeline system which is unaccounted for.

The quantity of gas lost by leakage and other emission sources is estimated by the following algorithm:

$$V_p = UAG_p \mathbf{x} UAG_f \qquad (1B2\_10)$$

Where V_p is the total gas emitted from the gas distribution system from State pipeline system p (in PJ);
UAG_p is the total unaccounted for gas in State pipeline system p (in PJ).
UAG_f is the ratio of emissions to UAG, and is:

- 1990 to1994 = 0.90
- 1995 to 2002 = increased by 0.038889 per year
- 2003 onward = 0.55

The mass of each greenhouse gas emitted from each State pipeline system is estimated by:

$$E_{i,p} = V_p \mathbf{x} C_{i,p} \qquad (1B2\_11)$$

Where $E_{i,p}$ is the total mass of greenhouse gas i emitted from the gas distribution system in State pipelines system p (in Gg),
V_p is the total mass of natural gas emitted from the gas distribution system in State pipeline system p (in PJ), and
$C_{i,p}$ is the natural gas composition factor for gas i for natural gas supplied from State pipelines system p (in Gg/PJ), from Appendix C.

National total emissions from the natural gas distribution system of greenhouse gas i are calculated according to:

$$E_i = \Sigma \; E_{i,p} \qquad (1B2\_12)$$

Where E_i is the total mass of greenhouse gas i emitted from the gas distribution system (in Gg), and
$E_{i,p}$ is the total mass of greenhouse gas i emitted from the gas distribution system (in Gg) calculated by algorithm (1B1_11).

1.B.2c Oil and Gas Production Venting and Flaring

Venting refers to the controlled release of unburnt gases to the atmosphere. Venting at oil and gas processing facilities is mainly associated with the release of CO_2, which is extracted from the raw gas stream in the course of gas processing. Because separation of the other components of the gas stream from the CO_2 is incomplete, the vented CO_2 contains small quantities of CH_4. The quantities of CO_2 and CH_4 vented will depend on the concentration of CO_2 in the raw gas, which varies significantly between gas fields, and on the mode of operation and efficiency of the CO_2 stripping plant. At all gas processing facilities, the volumes of the vent gas and CO_2 and CH_4 concentrations are monitored in routine plant operation. Venting of CH_4, meaning that CH_4 is released to the atmosphere without combustion in a flare, also occurs at a number of locations.

Flaring refers to the controlled release to combustion of a mixed flammable gas stream. At oil and gas processing plants, flared gas may arise from crude oil processing or natural gas processing. Where there is no market for gas separated from the wellhead production stream, the gas is reinjected or flared. With the growth in markets for natural gas and an increase in its value, some Australian petroleum production facilities now operate as combined oil and gas facilities, with both oil and gas as marketable products. At such facilities, smaller quantities of gas are flared as part of normal operation of the various processing units. Gas sent to flare is normally mostly CH_4 with smaller concentrations of other volatile hydrocarbons and is usually different in composition to

pipeline gas. As with venting, flaring is monitored as part of routine plant operation. Most state governments require oil and gas producing companies to provide regular reports of volumes of gas flared.

Venting – Gas

Emissions are based on direct measurement company data (APPEA). As indicated previously, the Australian Petroleum Production and Exploration Association (APPEA) publishes data on industry emissions in the form of a public annual inventory report to the Greenhouse Challenge Plus Program. The data is collected by means of a survey of industry companies. APPEA's inventories have been independently verified through the Greenhouse Challenge Program by PricewaterhouseCoopers and KPMG. The approach adopted here, of direct measurement, is equivalent to a *Tier 3* estimation, or highest-order approach.

Flaring – Oil and Gas combined

Emissions reported combines flaring from both oil and gas sources (APPEA). Emission factors can be found in Appendix B, and are sourced from the E and P Forum (1994).

GLOSSARY

Beneficiation means any process which upgrades the value of a mineral by removing waste material; as applied to coal, beneficiation usually involves washing raw coal to reduce the ash content.

Black coal consists of three main types. These are:

> **Anthracite** is coal of the highest rank. It is a hard coal containing a low level of volatile matter. Anthracite is not produced in Australia.
>
> **Bituminous coals** are coals having between 15 and 50 per cent volatile matter and high in carbonaceous matter. They are intermediate in rank between sub-bituminous and anthracite coals.
>
> **Sub-bituminous coals** are coals that are of lower rank than bituminous coals, but higher than lignite (brown coal). Sub-bituminous coals generally have high inherent moisture and are also high in volatile matter (42 to 49 per cent on a dry mineral matter free basis).

Brown coal or lignite is a low rank coal having high volatile matter content and high inherent moisture. Brown coal use in Australia is confined to the State of Victoria and almost exclusively limited to steam raising for electricity generation.

Class A underground coal mines are mines which are defined as "gassy" by the coal industry.

Class B underground coal mines are mines which are defined as "not gassy" by the coal industry.

Coal rank is a reference to the degree of maturity of a coal in terms of its physical and chemical properties. It is a classification based on the degree of progressive alteration in the series from lignite, through bituminous coal to anthracite. Rank is related to depth of burial (and therefore pressure), the temperature attained during burial and length of time elevated temperatures were maintained. High rank coals, such as bituminous coal, will generally contain more CH_4 than low rank coals, such as brown coal or lignite.

Composition factors express the proportion of each gas species in a gas mixture, such as pipeline natural gas, on the basis of either the mass or volume of the gas mixture.

Condensate is a mixture of liquid hydrocarbons, mostly containing six or more carbon atoms, i.e. heavier than pentane, which occur in association with natural gas and are separated from the raw gas stream at gas processing plants. It is sometimes referred to as natural gasoline and is normally used as a refinery feedstock. In production statistics, condensate is often included with crude oil.

Crude oil is a mineral oil consisting of a mixture of hydrocarbons of natural origin, being yellow to black in colour and of variable density and viscosity.

Distribution system is defined as that part of oil and natural gas supply system devoted to distributing the final product to end users. In relation to the oil system this covers the distribution of petroleum products from the refinery to the point of use, and may include terminals, pipelines, road and rail tankers, depots, service stations and storage tanks on customers' premises. In relation to the natural gas system, the distribution system includes pipeline reticulation from the end of a high pressure transmission pipeline to the point of combustion on customers' premises.

Emission factors are used to indicate the quantity of greenhouse gases emitted per unit of some specified activity. The activity may be quantity of fossil fuel combusted, but it may alternatively be throughput, eg of a gas transmission pipeline or an oil refinery.

Flaring is the process of combusting unwanted or excess gases at a crude oil or gas production site, a gas processing plant or an oil refinery.

Fugitive emissions are not fully controlled, but in most cases not accidental, and typically result from leaks, including those from pump seals, pipe flanges and valve stems. Coal mine ventilation air discharge contains methane emitted from the exposed seams. Fugitive emissions of methane also come from open cut mines and coal storage. During petroleum storage tank filling, venting loss of vapour is a fugitive emission.

Greenhouse gases for the purposes of this workbook include carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), tetrafluoromethane (CF_4), hexafluoroethane (C_2F_6), hydrofluorocarbons (HFCs) and sulphur hexafluoride (SF_6). In addition, the photochemically important gases non-methane volatile organic compounds (NMVOC), oxides of nitrogen (NO_X) and carbon monoxide (CO) are also considered. NMVOC, NO_X and CO are not direct greenhouse gases. However, they contribute indirectly to the greenhouse effect by influencing the rate at which ozone and other greenhouse gases are produced and destroyed in the atmosphere.

Gross calorific value (GCV) is the quantity of heat released by unit quantity of fuel, when it is burned completely with oxygen, and the products of combustion are returned to liquid water at ambient temperature (101 kPa and 25^{o}C). GCV is measured per unit mass or unit volume. GCV is also known as higher heating value (HHV).

Liquefied petroleum gas (LPG) is a light hydrocarbon fraction of the paraffin series. It occurs naturally, associated with crude oil and natural gas in many oil and gas deposits, and is also produced in the course of petroleum refinery processes. LPG consists of propane (C_3H_8) and butane (C_4H_{10}) or a mixture. In Australia, LPG as marketed contains more propane than butane. LPG is used in a variety of sectors, such as for feedstocks in the chemical industry, fuel in motor vehicles and for heating and cooking purposes.

Natural gas consists primarily of methane (around 90 per cent by volume, with traces of other gaseous hydrocarbons, as well as nitrogen and carbon dioxide) occurring naturally in underground deposits. Production is measured after processing to extract heavier hydrocarbons (comprising LPG and condensate) and impurities, such as sulphur containing compounds and carbon dioxide.

Natural gas liquids are the liquid or liquefied hydrocarbons produced in the manufacture, purification and stabilisation of natural gas. Natural gas liquids include ethane, propane, butane, pentane and condensate.

Oxidation, as used in this workbook, is the process by which fuel is consumed by burning with oxygen.

Petroleum as used in this workbook, refers solely to oil related products or processes. The phrase "oil production" can be taken to mean crude oil production only. Where petroleum and natural gas are included in the same total, the phrase "oil and gas production" is used.

Processing, when related to natural gas, refers to the activity of separating raw gas into different product streams, such as pipeline quality natural gas, ethane, LPG and condensate, and removal of undesirable components of the raw gas stream, such as CO_2 and sulphur compounds.

Transmission and storage is defined as that part of the oil and gas system that involves the transmission of raw and final product between the point of extraction and the distribution system. For oil, this may include transport along pipelines or by tanker (ship, rail or road). Gas is typically transported by high pressure pipeline although it may be converted to LNG and shipped by tanker.

Unaccounted for gas is the difference between the amount of gas issued over a given period as indicated by the distributors purchase meter records and the gas sales billed to customers over the same period (Hutchinson et al. 1993).

Venting is the process of releasing gas into the atmosphere without combustion. This may be done either at the production site or at the refinery/stripping plants. It is done to dispose of non-commercial gas or to relieve system pressure when required.

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Fugitive Emissions Appendix A: Coal mining and handling

Categorisation of Underground Coal Mines 2006

Table 8: Categorised list of New South Wales operating underground mines

CLASS A MINES	CLASS B MINES
Appin	Angus Place
Ashton	Austar
Cooranbong/Mandalong	Awaba
Dartbrook	Baal Bone
Delta (formerly Elouera)	Beltana No.1
Dendrobium	Berrima
Glennies Creek	Chain Valley
Metropolitan	Charbon
Myuna	Clarence
Newstan	Ivanhoe
Tahmoor	Mannering
United	Newpac
Wambo	NRE No.1
West Cliff	Springvale
	Ulan
	West Wallsend

Table 9: Categorised list of Queensland underground mines

CLASS A MINES	CLASS B MINES
Broadmeadow	Cook
German Creek Central	Crinum
German Creek Southern	Newlands
Grasstree	Kestrel
Moranbah North	
North Goonyella	
Oaky Creek No.1	
Oaky North	

Fugitive Emissions Appendix B: Oil

1. Emission factors for petroleum products distribution

Table 10: NMVOC emission factors for service station storage and transfer operations

Region	Population (million)[(a)]	Emission factor (kg per kl distributed)[(b)]
Sydney Statistical Region[(c)]	3.67	0.16
Port Phillip Control Region[(d)]	3.39	0.16
Other	10.22	1.00
Australia[(e)]	17.28	0.66

Sources: *(a)* Australian Bureau of Statistics, Census 1991.
(b) Filling losses and underground-tank breathing.
(c) Environment Protection Authority NSW (1995).
(d) Melbourne, Geelong and Westernport Regions, Environment Protection Authority Victoria (1991).
(e) Population weighted average, all years 1988-1994.

Table 11: NMVOC emission factors for bulk fuel storage facilities

Region	Population (million)[(a)]	Emission factor (kg per kl distributed)[(b)]
Melbourne/Sydney Region[(c)]	7.06	0.48
Other[(d)]	10.22	1.49
Australia[(e)]	17.28	1.08

Sources: *(a)* Australian Bureau of Statistics, Census 1991.
(b) Storage and working losses
(c) Assume emission factors in Melbourne (Environment Protection Authority Victoria, (1991) and Sydney are similar because control regulations are identical
(d) From Australian Environment Council (1988) data for regions outside Melbourne and Sydney.
(e) Population weighted average, all years 1988-1994.

2. Emission Factors for Oil and Gas Production

Table 12: Oil and Gas emission factors used for emissions based on APPEA inventory

NGGI Category	Operation/source	Tonnes emissions / Tonnes combustion					
		CO_2	CH_4	NMVOC	N2O	NOx	CO
Exploration (for both oil and gas)	**Mobile Offshore Drilling Units**						
	Production testing						
	- Gas Flared	2.75	0.035	0.015	$8.1x10^{-5}$	0.0015	0.0087
	- Oil Flared	3.2	$3.3x10^{-4}$	0.00297	$2.2x10^{-4}$	0.0037	0.018
	Land Based Drilling Units						
	Production testing						
	- Gas Flared	2.75	0.035	0.015	$8.1x10^{-5}$	0.0015	0.0087
	- Liquid Flared	3.2	$3.3x10^{-4}$	0.00297	$2.2x10^{-4}$	0.0037	0.018
Venting and Flaring							
Venting	**Gas Venting**	D	D	D	0	0	0
Flaring	**Flares**	2.9	0.035	0.015	$8.1x10^{-5}$	0.0015	0.0087
		Tonnes emissions / Tonnes production					
Crude oil production	**Fugitive emissions**						
	- Internal Floating tank		$4x10^{-8}$	$2x10^{-7}$	0	0	0
	- Fixed roof tank		$2x10^{-7}$	$1.12x10^{-4}$	0	0	0
	- Floating tank		$1.5x10^{-7}$	$8.5x10^{-7}$	0	0	0
Natural Gas Production and processing	**Fugitive emissions**						
	- General leaks		$5.78x10^{-5}$	$7x10^{-6}$	0	0	0

Source: E and P Forum 1994, D = Directly measured emissions

Fugitive Emissions Appendix C: Natural Gas

Table 13: Natural gas composition and emission factors, 2000 to 2006[(a)]

Pipeline	Longford, Melbourne (Victoria)	Moomba, Sydney, Adelaide (NSW, SA)	Roma, Brisbane (Qld)	Denison Trough, Gladstone (Qld)	Dampier, Perth (WA)	Dongarra, Perth (WA)	Amadeus, Darwin (NT)	Australia (weighted average)
kg CO_2/GJ (content)	0.9	0.8	0.8	0.7	1.0	1.5	0.0	0.8783
kg CH_4/GJ (content)	15.5	15.6	15.0	16.0	13.9	16.2	12.6	14.9
kg NMVOC/GJ (content)	2.5	2.4	3.2	1.8	4.3	1.8	5.8	3.2
Weighted state averages:								
kg CO_2/GJ (content)			0.8		1.1			
kg CH_4/GJ (content)			15.1		14.3			
kg NMVOC/GJ (content)			3.1		3.9			

(a) In previous years, emission factors for both combustion and fugitive natural gas emissions have been calculated from pipeline gas composition data, published by the Australian Gas Association. However, as from 2001 the Association no longer collect this data from its members. It has been assumed that all natural gas emission factors are unchanged from 2000.

Table 14: Natural gas composition and emission factors, 1999–2000

Pipeline	Longford, Melbourne (Victoria)	Moomba, Sydney, Adelaide (NSW, SA)	Roma, Brisbane (Qld)	Denison Trough, Gladstone (Qld)	Dampier, Perth (WA)	Dongarra, Perth (WA)	Amadeus, Darwin (NT)	Australia (weighted average)
Methane [a]	90.1	89.9	88.8	90.8	83.9	91.1	75.7	
Ethane [a]	5.8	7.2	6.5	3.2	7.2	2.9	10.7	
Propane [a]	1.1	0.1	1.5	1.0	3.1	0.9	3.3	
Butane [a]	0.2	0.0	0.5	0.2	1.0	0.3	1.1	
Pentane [a]	0.0	0.0	0.1	0.1	0.1	0.1	0.3	
Hexane [a]	0.0	0.0	0.1	0.1	0.0	0.1	0.1	
CO2 [a]	1.9	1.6	1.8	1.5	2.3	3.0	0.0	
$MJ/^{m3}$	39.3	38.9	40.1	38.3	40.8	38.0	40.7	
$KgCO_2/GJ$ (content)	0.9	0.8	0.8	0.7	1.0	1.5	0.0	0.8783
$KgCH_4/GJ$ (content)	15.5	15.6	15.0	16.0	13.9	16.2	12.6	14.9
KgNMVOC/GJ (content)	2.5	2.4	3.2	1.8	4.3	1.8	5.8	3.2
State sales to end users	192.9	198.6	80.6		257.8		26.2	
% State sales	100%	100%	60%	40%	96%	4%	100%	
Pipeline sales	192.9	198.6	48.4	32.2	247.8	10.0	26.2	
State utility sales (PJ)	177.9	144.9	19.7		64.5		0.1	
Pipeline utility sales (PJ)	177.9	144.9	17.7	2.0	54.5	10.0	0.1	
% State utility sales	100%	100%	90%	10%	84.6%	15.4%	100%	
Weighted state averages:								
$KgCO_2/GJ$ (content)			0.8		1.1			
$KgCH_4/GJ$ (content)			15.1		14.3			
KgNMVOC/GJ (content)			3.1		3.9			

[a] % of natural gas by volume

Table 15: Natural gas composition and emission factors, 1998-99

Pipeline		Longford, Melbourne (Victoria)	Moomb, Sydney, Adelaide (NSW, SA)	Roma, Brisbane (Qld)	Denison Trough, Gladstone (Qld)	Dampier, Perth (WA)	Dongarra, Perth (WA)	Amadeus, Dawin (NT)	Australia (weighted average)
Methane	% of natural gas by volume P_{pc}	91.6	89.9	90.4	91.5	84.3	92.7	75.8	
Ethane		5.2	7.2	5.7	2.5	7.2	3.0	10.9	
Propane		0.7	0.1	1.2	0.9	3.1	0.9	3.3	
Butane		0.1	0.0	0.4	0.2	1.0	0.3	1.1	
Pentane		0.0	0.0	0.1	0.1	0.0	0.1	0.3	
Hexane		0.0	0.0	0.1	0.1	0.0	0.1	0.1	
CO_2		1.6	1.6	2.0	1.3	2.3	2.3	0.0	
MJ/m^3	E_p	38.9	38.9	39.3	37.9	40.8	38.4	40.7	
$KgCO_2/GJ$ (content)	$V_{pCO2;c}$	0.8	0.8	0.9	0.6	1.0	1.1	0.0	0.8464
$KgCH_4/GJ$ (content)	$V_{pCH4;c}$	15.9	15.6	15.6	16.3	14.0	16.3	12.6	15.1
KgNMVOC/GJ (content)	$V_{pNMVOCs;c}$	2.1	2.4	2.8	1.6	4.3	1.8	5.9	3.1
State sales to end users (PJ)		181.3	184.7	109.0		273.0		28.0	
% State sales		100%	100%	60%	40%	97%	3%	100%	
Pipeline sales (PJ)		181.3	184.7	65.4	43.6	264.7	8.3	28.0	
State utility sales (PJ)		170.5	132.3	16.1		68.3		0.1	
Pipeline utility sales (PJ)	S_p	170.5	132.3	14.5	0.0	60.0	8.3	0.1	
% State utility sales		100%	100%	90%	10%	87.9%	12.1%	100%	
Weighted State averages:									
$kgCO_2/GJ$ (content)				0.9		1.1			
$kgCH_4/GJ$ (content)				15.6		14.3			
kgNMVOC/GJ (content)				2.7		4.0			

Table 16: Natural gas composition and emission factors, 1997-98

Pipeline		Longford, Melbourne (Victoria)	Moomba, Sydney, Adelaide (NSW, SA)	Roma, Brisbane (Qld)	Denison Trough, Gladstone (Qld)	Dampie, Perth (WA)	Dongarra, Perth (WA)	Amadeus, Dawin (NT)	Australia (weighted average)
Methane	% of natural gas by volume P_{pc}	91.6	89.9	88.5	90.0	85.8	91.8	78.2	
Ethane		5.0	7.2	6.1	3.7	6.0	2.3	10.2	
Propane		0.4	0.1	1.4	1.1	2.7	0.5	2.8	
Butane		0.1	0.0	0.5	0.2	0.8	0.2	0.9	
Pentane		0.0	0.0	0.1	0.1	0.1	0.1	0.2	
Hexane		0.0	0.0	0.1	0.1	0.0	0.1	0.2	
CO_2		2.1	1.6	1.2	1.7	2.1	3.5	0.0	
MJ/m^3	E_p	38.5	38.9	39.7	38.6	40.8	37.4	40.6	
$kgCO_2/GJ$ (content)	$V_{pCO2;c}$	1.0	0.8	0.6	0.8	1.0	1.7	0.0	0.9
$kgCH_4/GJ$ (content)	$V_{pCH4;c}$	16.1	15.6	15.1	15.8	14.2	16.6	13.0	15.2
kgNMVOC/GJ (content)	$V_{pNMVOCs;c}$	1.9	2.4	3.1	2.0	3.7	1.3	5.3	2.8
State Sales to End Users		190.5	189.5	51.7		235.3		21.6	
% Sate Sales		100%	100%	60%	40%	95%	5%	100%	
Pipeline Sales		190.5	189.5	31.0	20.7	222.6	12.7	21.6	
Sate Utility Sales (PJ)		176.3	147.9	11.4	11.4		12.7	0.1	
Pipeline Utility Sales (PJ)	S_p	176.3	147.9	11.4	0.0	35.5	11.4	0.1	
% State Utility Sales		100%	100%	100%	0%	10.3%	89.7%	100%	
Weighted State Averages:									
$kgCO_2/GJ$ (content)				0.6		1.7			
$kgCH_4/GJ$ (content)				15.1		16.4			
kgNMVOC/GJ (content)				3.1		1.6			

Table 17: Natural gas composition and emission factors, 1996-97

Pipeline		Longford-Melbourne (Victoria)	Moomba, Sydney, Adelaide (NSW, SA)	Roma, Brisbane (Qld)	Denison Trough, Gladstone (Qld)	Dampier, Perth (WA)	Dongarra, Perth (WA)	Amadeus, Dawin (NT)	Australia (weighted average)
Methane	% of natural gas by volume P_{pc}	91.2	90.6	87.6	89.4	84.3	92.4	77.8	
Ethane		5.2	6.7	7.3	4.3	7.3	2.1	10.5	
Propane		0.6	0.1	1.0	1.1	3.1	0.5	3.0	
Butane		0.1	0.0	0.2	0.3	1.2	0.2	0.9	
Pentane		0.0	0.0	0.1	0.1	0.0	0.1	0.3	
Hexane		0.0	0.0	0.1	0.1	0.0	0.1	0.1	
CO_2		2.2	1.6	1.5	1.5	2.7	3.4	0.1	
MJ/m^3	E_p	38.6	38.8	39.5	38.7	41.1	37.3	40.9	
$kgCO_2/GJ$ (content)	$V_{pCO2;c}$	1.1	0.8	0.4	0.7	1.2	1.7	0.0	1.0
$kgCH_4/GJ$ (content)	$V_{pCH4;c}$	16.0	15.8	15.0	15.6	13.9	16.8	12.9	15.2
kgNMVOC/GJ (content)	$V_{pNMVOCs;c}$	2.1	2.2	3.1	2.3	4.4	1.3	5.5	2.9
State sales to end users		190.6	175.9	38.3		203.0		16.5	
% State sales		100%	100%	60%	40%	93%	7%	100%	
Pipeline sales		190.6	175.9	23.0	15.3	189.6	13.4	16.5	
State utility sales (PJ)		171.7	143.6	11	11	47.6	47.6	0.1	
Pipeline utility sales (PJ)	S_p	171.7	143.6	11.0	0.0	35.5	12.1	0.1	
% State utility sales		100%	100%	100%	0%	74.7%	25.3%	100%	
Weighted state averages:									
$kgCO_2/GJ$ (content)				0.4		1.3			
$kgCH_4/GJ$ (content)				15.0		14.6			
kgNMVOC/GJ (content)				3.1		3.6			

Table 18 Natural gas composition and emission factors, 1995-96

Note	Pipeline		Longford, Melbourne (Victoria)	Moomba, Sydney, Adelaide (NSW, SA)	Roma, Brisbane (Qld)	Denison Trough, Gladstone (Qld)	Dampier, Perth (WA)	Dongarra, Perth (WA)	Amadeus, Darwin (NT)	Australia (weighted average)
	Methane	% of natural gas by volume P_{pc}	91.1	88.0	88.3	90.2	84.5	90.9	77.1	
	Ethane		5.1	8.4	6.8	3.6	6.7	2.9	10.7	
	Propane		0.7	0.2	0.8	1.2	3.1	0.9	3.1	
(1)	Butane		0.1	0.0	0.3	0.3	1.2	0.3	0.3	
	Pentane		0.0	0.0	0.1	0.1	0.0	0.1	0.1	
	Hexane		0.0	0.0	0.1	0.1	0.0	0.1	0.1	
	CO_2		1.9	2.2	0.6	1.6	2.6	3.4	0.0	
(2)	MJ/m^3	E_p	38.7	38.8	39.3	38.7	40.7	37.8	40.9	
(3), (4)	$kgCO_2/GJ$ (content)	$V_{pCO2;c}$	1.0	1.1	1.3	0.8	1.2	1.7	0.0	1.0
(3), (5)	$kgCH_4/GJ$ (content)	$V_{pCH4;c}$	15.9	15.3	15.2	15.8	14.0	16.3	12.8	15.1
(3), (6)	kgNMVOC/GJ (content)	$V_{pNMVOCs;c}$	2.1	2.8	2.9	2.1	4.2	1.8	5.1	3.0
	State sales to end users		214.2	178.1	38.1		190.5		16.4	
	% State sales		100%	100%	60%	40%	93%	7%	100%	
	Pipeline sales		214.2	178.1	22.9	15.2	177.1	13.4	16.4	
(7)	State utility sales (PJ)		171.7	143.6	11.0	11.0	47.6	47.6	0.1	
(8)	Pipeline utility sales (PJ)	S_p	171.7	143.6	11.0	0.0	35.5	12.1	0.1	
	% State utility sales		100%	100%	100%	0%	75%	25%	100%	
	Weighted state averages:									
	$kgCO_2/GJ$ (content)				0.3		1.3			
	$kgCH_4/GJ$ (content)				15.2		14.6			
	kgNMVOC/GJ (content)				2.9		3.6			

Table 19: Natural gas composition and emission factors, 1994-95

Note	Pipeline		Longford, Melbourne (Victoria)	Moomba, Sydney, Adelaide (NSW, SA)	Roma, Brisbane (Qld)	Denison Trough, Gladstone (Qld)	Dampier, Perth (WA)	Dongarra, Perth (WA)	Amadeus, Darwin (NT)	Australia (weighted average)
	Methane	% of natural gas by volume P_{pc}	91.5	88.0	88.5	89.4	84.0	92.1	79.1	
	Ethane		gas by	8.4	6.4	4.3	6.7	2.2	10.2	
	Propane		volume	0.2	0.7	1.2	3.4	0.6	2.8	
(1)	Butane		P_{pc}	0.0	0.3	0.2	1.2	0.2	0.9	
	Pentane			0.0	0.0	0.1	0.1	0.0	0.1	0.2
	Hexane			0.0	0.0	0.1	0.1	0.0	0.1	0.1
	CO_2			1.9	2.2	0.8	1.5	2.7	3.4	0.1
(2)	MJ/m^3	E_p		38.6	38.8	38.9	38.6	40.9	37.5	40.8
(3), (4)	$kgCO_2/GJ$ (content)	$V_{pCO2;c}$		0.9	1.1	0.4	0.7	1.2	1.7	0.0	1.0
(3), (5)	$kgCH_4/GJ$ (content)	$V_{pCH4;c}$		16.0	15.3	15.4	15.7	13.9	16.6	13.1	15.2
(3), (6)	kgNMVOC/GJ (content)	$V_{pNMVOCs;c}$		2.0	2.8	2.8	2.3	4.3	1.4	5.2	3.0
	State sales to end users			217.6	187.0	38.9		189.9		15.1	
	% State sales			100%	100%	60%	40%	93%	7%	100%	
	Pipeline sales			217.6	187.0	23.3	15.6	176.5	13.4	15.1	
(7)	State utility sales (PJ)			171.8	141.2	11.2	11.2	47.3	47.3	0.1	
(8)	Pipeline utility sales (PJ)	S_p		171.8	141.2	11.2	0.0	35.2	12.1	0.1	
	% State utility sales			100%	100%	100%	0%	75%	25%	100%	
	Weighted state averages:										
	$kgCO_2/GJ$ (content)					0.4		1.3			
	$kgCH_4/GJ$ (content)					15.4		14.6			
	kgNMVOC/GJ (content)					2.8		3.6			

Table 20: Natural gas composition and emission factors, 1993–94

Note	Pipeline		Longford, Melbourne (Victoria)	Moomba, Sydney, Adelaide (NSW, SA)	Roma, Brisbane (Qld)	Denison Trough, Gladstone (Qld)	Dampier, Perth (WA)	Dongarra, Perth (WA)	Amadeus, Darwin (NT)	Australia (weighted average) (12)
	Methane	% of natural gas by volume P_{pc}	91.2	88.5	88.5	88.5	88.1	92.8	80.9	
	Ethane		5.1	8.0	5.7	4.8	5.3	2.0	10.4	
	Propane		0.5	0.2	0.6	1.2	2.0	0.4	2.5	
(1)	Butane		0.1	0.0	0.3	0.5	0.7	0.2	1.0	
	Pentane		0.0	0.0	0.1	0.2	0.0	0.1	0.4	
	Hexane		0.0	0.0	0.1	0.2	0.0	0.1	0.2	
	CO_2		2.2	2.1	0.7	1.5	2.6	3.3	0.0	
(2)	MJ/m^3	E_p	38.5	38.8	38.5	39.0	39.7	37.5	41.9	
(3), (4)	$kgCO_2/GJ$ (content)	$V_{pCO2;c}$	1.1	1.0	0.3	0.7	1.2	1.6	0.0	1.0
(3), (5)	$kgCH_4/GJ$ (content)	$V_{pCH4;c}$	16.0	15.4	15.6	15.4	15.0	16.7	13.1	15.5
(3), (6)	kgNMVOC/GJ (content)	$V_{pNMVOCs;c}$	2.0	2.7	2.5	2.8	3.1	1.2	5.3	2.6
(7)	Total state consumption (PJ)		232.5	210.6	43.8	43.8	232.8	232.8	13.7	
(8)	State cons. excl. gas processing (PJ)		213.9	189.5	39.8		171.7		13.6	
(9)	Pipeline % of State consumption		100%	100%	60%	40%	94%	6%	100%	
	Pipeline consumption (PJ)		213.9	189.5	23.9	15.9	161.4	10.3	13.6	
(10)	State utility sales (PJ)		156.1	132.4	10.7	10.7	121.1	121.1	0.1	
(11)	Pipeline utility sales (PJ)	S_p	156.1	132.4	10.7	0.0	114.3	6.8	0.1	
	% State sales		100%	100%	100%	0%	94%	6%	100%	
	Weighted state averages:									
	$kgCO_2/GJ$ (content)				0.3		1.2			
	$kgCH_4/GJ$ (content)				15.6		15.1			
	kgNMVOC/GJ (content)				2.5		3.0			

Table 21: Natural gas composition and emission factors, 1992-93

Note	Pipeline		Longford, Melbourne (Victoria)	Moomba, Sydney, Adelaide (NSW, SA)	Roma, Brisbane (Qld)	Denison Trough, Gladstone (Qld)	Dampier, Perth (WA)	Dongarra, Perth (WA)	Amadeus, Darwin (NT)	Australia (weighted average) (12)
	Methane	% of natural gas by volume P_{pc}	91.0	88.5	89.1	89.9	88.1	93.2	82.0	
	Ethane		5.1	8.0	6.4	4.1	5.2	1.9	9.6	
	Propane		0.8	0.1	0.5	1.1	2.0	0.4	2.3	
(1)	Butane		0.1	0.0	0.3	0.4	0.7	0.2	0.7	
	Pentane		0.0	0.0	0.1	0.1	0.0	0.1	0.2	
	Hexane		0.0	0.0	0.0	0.1	0.0	0.3	0.1	
	CO_2		2.1	2.4	0.7	1.5	2.6	2.6	0.1	
(2)	MJ/m^3	E_p	38.5	38.8	39.1	38.6	39.6	37.5	40.7	
(3), (4)	$kgCO_2/GJ$ (content)	$V_{pCO2;c}$	1.0	1.2	0.3	0.7	1.2	1.3	0.0	1.1
(3), (5)	$kgCH_4/GJ$ (content)	$V_{pCH4;c}$	16.0	15.4	15.4	15.8	15.1	16.8	13.6	15.5
(3), (6)	kgNMVOC/GJ (content)	$V_{pNMVOCs;c}$	2.1	2.7	2.6	2.3	3.0	1.3	4.7	2.6
(7)	Total state consumption (PJ)		245.7	200.8	39.4	39.4	207.0	207.0	13.8	
(8)	State cons. excl. gas processing (PJ)		222.6	180.4	35.8		151.6		13.8	
(9)	% State consumption		100%	100%	60%	40%	96%	4%	100%	
	Pipeline consumption (PJ)		222.6	180.4	21.5	14.3	146.1	5.5	13.8	
(10)	State utility sales (PJ)		160.5	126.8	9.9	9.9	114.5	114.5	0.1	
(11)	Pipeline utility sales (PJ)	S_p	160.5	126.8	9.9	0.0	107.7	6.8	0.1	
	% State sales		100%	100%	100%	0%	94%	6%	100%	
	Weighted state averages:									
	$kgCO_2/GJ$ (content)				0.3		1.2			
	$kgCH_4/GJ$ (content)				15.4		15.2			
	kgNMVOC/GJ (content)				2.6		2.9			

Table 22: Natural gas composition and emission factors, 1991-92

Note	Pipeline		Longford, Melbourne (Victoria)	Moomba, Sydney, Adelaide (NSW, SA)	Roma, Brisbane (Qld)	Denison Trough, Gladstone (Qld)	Dampier, Perth (WA)	Dongarra, Perth (WA)	Amadeus, Darwin (NT)	Australia (weighted average) (12)
(1)	Methane	% of natural gas by volume P_{pc}	91.2	89.8	89.1	89.0	88.1	92.3	82.0	
	Ethane		5.0	7.2	6.4	5.0	5.2	1.8	9.6	
	Propane		0.6	0.2	0.5	1.0	2.1	0.5	2.3	
	Butane		0.1	0.0	0.3	0.5	0.7	0.2	0.7	
	Pentane		0.0	0.0	0.1	0.1	0.0	0.1	0.2	
	Hexane		0.0	0.0	0.0	0.1	0.0	0.1	0.1	
	CO_2		2.1	1.8	0.7	1.4	2.7	3.3	0.1	
(2)	MJ/m^3	E_p	38.5	38.8	39.1	38.9	39.4	37.0	40.7	
(3), (4)	$kgCO_2/GJ$ (content)	$V_{pCO2;c}$	1.0	0.9	0.3	0.7	1.3	1.7	0.0	1.0
(3), (5)	$kgCH_4/GJ$ (content)	$V_{pCH4;c}$	16.0	15.7	15.4	15.5	15.1	16.9	13.6	15.6
(3), (6)	kgNMVOC/GJ (content)	$V_{pNMVOCs;c}$	2.0	2.5	2.6	2.6	3.1	1.2	4.7	2.5
(7)	Total state consumption (PJ)		239.1	197.8	39.1	39.1	189.0	189.0	13.6	
(8)	State cons. excl. gas processing (PJ)		216.0	177.1	36.3		145.2		13.6	
(9)	% State consumption		100%	100%	60%	40%	96%	4%	100%	
	Pipeline consumption (PJ)		216.0	177.1	21.8	14.5	139.4	5.8	13.6	
(10)	State utility sales (PJ)		158.1	121.9	9.7	9.7	114.8	114.8	0.1	
(11)	Pipeline utility sales (PJ)	S_p	158.1	121.9	9.7	0.0	108.0	6.8	0.1	
	% State sales		100%	100%	100%	0%	94%	6%	100%	
	Weighted state averages:									
	$kgCO_2/GJ$ (content)				0.3		1.3			
	$kgCH_4/GJ$ (content)				15.4		15.2			
	kgNMVOC/GJ (content)				2.6		3.0			

Table 23: Natural gas composition and emission factors, 1990-91

Note	Pipeline		Longford, Melbourne (Victoria)	Moomba, Sydney, Adelaide (NSW, SA)	Roma, Brisbane (Qld)	Denison Trough, Gladstone (Qld)	Dampier, Perth (WA)	Dongarra, Perth (WA)	Amadeus, Darwin (NT)	Australia (weighted average) (12)
	Methane	% of natural gas by volume P_{pc}	91.2	89.8	89.9	88.7	87.8	92.5	84.5	
	Ethane		5.5	7.2	6.3	4.5	5.2	1.6	9.2	
	Propane		0.4	0.2	0.5	1.2	2.1	0.5	1.9	
(1)	Butane		0.0	0.0	0.2	0.3	0.7	0.2	0.6	
	Pentane		0.0	0.0	0.1	0.1	0.0	0.1	0.2	
	Hexane		0.0	0.0	0.0	0.1	0.0	0.1	0.1	
	CO_2		2.1	1.8	0.6	1.7	3.0	2.9	0.0	
(2)	MJ/m^3	E_p	38.6	38.8	39.2	38.9	39.6	37.0	40.9	
(3), (4)	$kgCO_2/GJ$ (content)	$V_{pCO2;c}$	1.0	0.9	0.3	0.8	1.4	1.5	0.0	1.0
(3), (5)	$kgCH_4/GJ$ (content)	$V_{pCH4;c}$	16.0	15.7	15.5	15.4	15.0	16.9	14.0	15.6
(3), (6)	kgNMVOC/GJ (content)	$V_{pNMVOCs;c}$	2.0	2.5	2.5	2.4	3.1	1.1	4.3	2.5
(7)	Total state consumption (PJ)		231.1	193.1	37.0	37.0	181.3	181.3	13.2	
(8)	State cons. excl. gas processing (PJ)		210.0	171.6	35.4		141.1		13.1	
(9)	% State consumption		100%	100%	60%	40%	96%	4%	100%	
	Pipeline consumption (PJ)		210.0	171.6	21.2	14.1	135.3	5.9	13.1	
(10)	State utility sales (PJ)		156.2	121.6	8.9	8.9	111.9	111.9	0.1	
(11)	Pipeline utility sales (PJ)	S_p	156.2	121.6	8.9	0.0	105.1	6.8	0.1	
	% State sales		100%	100%	100%	0%	94%	6%	100%	
	Weighted state averages:									
	$kgCO_2/GJ$ (content)				0.3		1.4			
	$kgCH_4/GJ$ (content)				15.5		15.1			
	kgNMVOC/GJ (content)									

Table 24: Natural gas composition and emission factors, 1989-90

Note	Pipeline		Longford, Melbourne (Victoria)	Moomba, Sydney, Adelaide (NSW, SA)	Roma, Brisbane (Qld)	Dampier, Perth (WA)	Dongarra, Perth (WA)	Amadeus, Darwin (NT)	Australia (weighted average) (12)
	Methane	% of natural gas by volume P_{pc}	91.0	92.8	88.2	87.2	92.5	83.5	
	Ethane		5.4	4.7	6.9	5.9	1.6	9.2	
	Propane		0.7	0.1	0.5	2.2	0.5	2.1	
(1)	Butane		0.1	0.0	0.3	0.7	0.2	0.6	
	Pentane		0.0	0.0	0.1	0.0	0.1	0.2	
	Hexane		0.0	0.1	0.1	0.0	0.1	0.1	
	CO_2		2.0	1.4	0.7	3.2	2.9	0.1	
(2)	MJ/m^3	E_p	38.7	38.2	39.0	39.8	37.0	40.9	
(3), (4)	$kgCO_2/GJ$ (content)	$V_{pCO2;c}$	1.0	0.7	0.3	1.5	1.5	0.0	1.0
(3), (5)	$kgCH_4/GJ$ (content)	$V_{pCH4;c}$	15.9	16.4	15.3	14.8	16.9	13.8	15.8
(3), (6)	kgNMVOC/GJ (content)	$V_{pNMVOCs;c}$	2.2	1.7	2.8	3.3	1.1	4.4	2.4
(7)	Total state consumption (PJ)		259.2	211.1	22.0	183.3	183.3	12.5	
(8)	State cons. excl. gas processing (PJ)		236.8	188.4	20.3	149.5		12.4	
(9)	% State consumption		100%	100%	100%	95%	5%	100%	
	Pipeline consumption (PJ)		236.8	188.4	20.3	142.7	6.8	12.4	
(10)	State utility sales (PJ)		161.7	125.6	9.1	112.1	112.1	0.1	
(11)	Pipeline utility sales (PJ)	S_p	161.7	125.6	9.1	107.1	5.0	0.1	
	% State sales		100%	100%	100%	96%	4%	100%	
	Weighted state averages:								
	$kgCO_2/GJ$ (content)					1.5			
	$kgCH_4/GJ$ (content)					14.9			
	kgNMVOC/GJ (content)					3.2			

NOTES FOR NATURAL GAS COMPOSITION TABLES

(1) Source: "Gas Industry Statistics", The Australian Gas Association, annual, various years. It is assumed for the purposes of calculation that all hydrocarbons higher than hexane are hexane. Totals do not add to 100%; it is assumed that the balance of gases do not contain carbon (the AGA simply list "nitrogen" and "other" for the balance).

(2) Source: "Gas Industry Statistics", loc. cit. These numbers are referred to below as E_p where p indicates the pipeline. They refer to a pressure of 1 atmosphere (101,325 Pa) and a temperature of 15^{o} C, and are gross values.

(3) $C_c = m_c \times P_{pc} \times 1 / molar\ volume \times 1 / E_p$
where C_c = mass of gas component c per GJ of gas associated with pipeline p vented
m_c = relative molecular mass of gas component c:

c	
Methane	16
Ethane	30
Propane	44
Butane	58
Pentane	72
Hexane	86
Carbon dioxide	44

Molar volume at 15^{o}C and 1 atm = 0.0236446 m^3
It is assumed that all vented gas is of pipeline quality.

(4) C_c for $c = CO_2$
(5) C_c for $c = CH_4$
(6) C_c for c = NMVOC, Where
$C_{NMVOC} = C_{ethane} + C_{propane} + C_{butane} + C_{pentane} + C_{hexane}$
(7) Source: ABARE: Bush, Holmes and Ho Trieu (1995), Table D.
(8) Data on gas use in processing assumed equal to gas used in the Oil and Gas Mining sector in each state, as advised by ABARE.
(9) Source: S. Bush, pers. comm.
(10) Source: "Gas Industry Statistics", The Australian Gas Association, annual, various years. Fugitive emissions from gas distribution are based on utility sales, not total sales, for reasons explained in the text.
(11) For Queensland, there are no utility sales from the Denison Trough to Gladstone pipeline.
For Western Australia, utility sales from the Dongara to Perth pipeline are assumed to equal 90% of total production from gasfields in the Perth Basin, as advised by the Department of Primary Industries and Energy.
(12)
$$Y_c = \frac{\Re_p \left(C_{c,p} \times S_p \right)}{\Re_p S_p}$$
Where Y_c = Australian weighted average emission factor for venting of gas component c.