WHITEHAVEN COAL

Narrabri Coal Operations Pty Ltd

ABN: 15 129 850 139

Narrabri Coal Mine
Stage 2 Longwall Project

Greenhouse Gas Assessment

Prepared by:
Heggies Pty Ltd

November 2009

Specialist Consultant Studies Compendium
Volume 2, Part 8

Narrabri Coal Operations Pty Ltd

ABN: 15 129 850 139

Narrabri Coal Mine
Stage 2 Longwall Project

Greenhouse Gas Assessment

Prepared for: R.W. Corkery & Co. Pty. Limited
Level 1, 12 Dangar Road
PO Box 239
BROOKLYN NSW 2083

Tel: (02) 9985 8511
Fax: (02) 9985 8208
Email: brooklyn@rwcorkery.com

On behalf of: Narrabri Coal Operations Pty Ltd
Level 9, 1 York Street
PO Box R1113
SYDNEY NSW 1225

Tel: (02) 8507 9700
Fax: (02) 8507 9701
Email: thaggarty@whitehaven.net.au

Prepared by: Heggies Pty Ltd
PO Box 176
LANE COVE NSW 2066

Tel: (02) 9427 8100
Fax: (02) 9427 8200
Email: sydney@heggies.com.au

November, 2009

MEMBER FIRM OF THE ASSOCIATION OF AUSTRALIAN ACOUSTICAL CONSULTANTS Heggies Pty Ltd is a Member Firm of the Association of Australian Acoustical Consultants.		Heggies Pty Ltd operates under a Quality System which has been certified by SAI Global Pty Limited to comply with all the requirements of ISO 9001:2008 "Quality management systems - Requirements" (Licence No 3236). This document has been prepared in accordance with the requirements of that System.

DOCUMENT CONTROL

Reference	Status	Date	Prepared	Checked	Authorised
10-7193R2	Revision 0	May, 2009	Martin Doyle	Ronan Kellaghan	Ronan Kellaghan
10-7193R2	Revision 1	August, 2009	Martin Doyle	Ronan Kellaghan	Ronan Kellaghan
10-7193R2	Revision 2	September, 2009	Martin Doyle	Scott Fishwick	Martin Doyle
10-7193R3	Revision 3	November, 2009	Martin Doyle	Scott Fishwick	Martin Doyle

CONTENTS

Page

CONTENTS

Page

FIGURES

TABLES

APPENDICES

EXECUTIVE SUMMARY

Heggies Pty Ltd has been commissioned by R.W. Corkery & Co. Pty. Limited on behalf of Narrabri Coal Operations Pty Ltd to undertake a Greenhouse Gas Assessment for the proposed Narrabri Coal Mine Stage 2 Longwall Project.

The Greenhouse Gas assessment is prepared in accordance with the NSW Department of Planning (DoP) Director-General's Requirements for assessment.

The assessment considers emissions of CH_4 and CO_2 from the proposed Stage 2 Longwall Project and includes estimates of direct and indirect GHG emissions.

A total of 19.5 Mt CO_2-equivalent (CO_2-e) is estimated to be generated on an annual basis once coal production reaches 8Mtpa. A total of 405 Mt CO_2-e is estimated to be generated during the mine life. The most significant emissions are associated with the final combustion of the coal product and fugitive emissions of coal seam gas through venting.

A comparison of the predicted direct (Scope 1) emissions against the 1990 national estimate demonstrates that operations would represent an annual increase of approximately 0.06 % of the total baseline Australian emissions. A comparison of the predicted emissions against NSW emissions in 2006 demonstrates that operations would represent an annual increase of approximately 0.3%.

This page has intentionally been left blank

1 INTRODUCTION

Heggies Pty Ltd (Heggies) has been commissioned by R.W. Corkery & Co. Pty. Limited (RWC) on behalf of Narrabri Coal Operations Pty Ltd (the Proponent) to undertake a Greenhouse Gas Assessment for the proposed Narrabri Coal Mine Stage 2 Longwall Project (the Longwall Project).

Narrabri Coal Mine is located approximately 30km south-southeast of Narrabri and 10km north-northwest of Baan Baa.

The Proponent proposes to convert the approved Narrabri Coal Mine from a continuous miner operation with an approved annual production rate of 2.5Mtpa to a longwall mining operation with a maximum annual production rate of 8Mtpa.

The scope of this assessment is limited to an assessment of Greenhouse Gas (GHG) Emissions from the Stage 2 Longwall Project.

Emissions of GHG are assessed within this report for an annual production rate of 8Mtpa.

1.1 Overview of the Project

Mining would involve the sequential development of roadways for longwall panels approximately 305m in width oriented north-south from the West Mains and developed for the full distance (up to approximately 4.115km) to the northern and southern boundaries of ML 1609.

Once each set of roadways are fully developed, the longwall equipment would be installed and the coal recovered as the longwall unit retreats back towards the West Mains between the two roadways. All coal would be conveyed back to the Pit Bottom Area for transfer to the surface via the conveyor drift.

It is envisaged that the overall coal production would be achieved through the combination of a single longwall unit and two or three continuous miners developing roadways for the longwall unit. It is envisaged that each panel would take approximately 12 months to mine.

The 170Mt of coal recoverable from the 26 longwall panels and associated development roadways would support a mine for a period of approximately 30 years based upon an annual production rate of up to 8.0Mt.

1.1.1 Mine Ventilation

A conceptual mine ventilation system has been developed to manage seam gas generated within the mine and to provide a safe working environment for the mine's workforce. Gas composition within the mine varies considerably but the dominant gas is CO_2 with significant concentrations of CH_4 and N_2 present.

The proposed ventilation system would incorporate:

- A number of concrete lined upcast ventilation shafts up to 6m in internal diameter. The initial shaft would be located approximately 200m in bye of the Pit Bottom.

- A total of twelve 2.1m smooth lined return shafts located at the end of every third gate road to draw fresh air from the surface to ventilate the active main gate roads.

1.1.2 Goaf Gas

A goaf drainage system has been designed with 250mm (ID) cased boreholes located about 30m off the tailgate corner of the active goaf at 200m intervals. The boreholes would be drilled to the top of the Hoskissons Seam and connected to surface via mobile goaf drainage vacuum plants.

1.1.3 Pre-Drainage

Each longwall panel would be pre-drained of gas prior to mining. A conceptual pre-drainage design utilising in-seam boreholes at a 20m spacing of the pre-drainage of Main Gates 6 and 7, has been outlined. The gas extracted from this process would be pumped into a surface pipeline reticulated to the main gas drainage pumping station located near the main upcast shaft.

1.2 Director-General's Requirements (DGRs)

The Greenhouse Gas assessment is prepared in accordance with the NSW Department of Planning (DoP) Director-General's Requirements for assessment.

The following outlines requirements specified by the NSW Department of Environment and Climate Change (DECC):

1. *A comprehensive assessment of and report on the project's predicted greenhouse gas emissions (tCO_2e), including emissions on:*
    - *a tonnes per unit of production basis;*
    - *a total annual emissions basis; and*
    - *a total project lifetime basis, including any construction and decommissioning activities.*
2. *The emissions associated with the project should include direct emissions, indirect emissions (eg. those associated with electricity use) and any significant upstream and/or downstream emissions associated with the project.*
3. *The emissions should be estimated using an appropriate methodology, as outlined in the Department of Planning's Draft Guidelines: Energy and Greenhouse in EIA (2002) and the Australian Greenhouse Office's Factors and Methods Workbook (2006).*
4. *Annual emissions should be compared against:*
    - *'best practice' emissions for the activity; and*
    - *total annual NSW emissions, so the impact of the proposal on NSW emissions reduction targets can be evaluated.*
5. *The Proponent should evaluate and report on the feasibility of additional measures to reduce greenhouse gas emissions, including offsets.*

The Proponent should demonstrate that all reasonable and feasible measures are undertaken to capture, treat and utilise greenhouse gases, particularly pre-drainage methane gas, from underground coal workings.

The following outlines requirements specified by the Namoi Catchment Management Authority (NCMA):

> *The EA needs to consider the disposal methods of the inseam gas, especially with regard to using the gas productively and accounting for it in a carbon balance.*

2 LEGISLATIVE FRAMEWORK

The Greenhouse Gas Protocol Initiative (hereafter the GHG Protocol) is a multi-stakeholder partnership of businesses, non-governmental organizations (NGOs), governments, and others convened by the World Resources Institute (WRI), a U.S.-based environmental NGO, and the World Business Council for Sustainable Development (WBCSD), a Geneva-based coalition of 170 international companies. Launched in 1998, the Initiative's mission is to develop internationally accepted greenhouse gas (GHG) accounting and reporting standards for business and to promote their broad adoption. (WBCSD, 2005).

The GHG Protocol comprises two separate but linked standards:

- *GHG Protocol Corporate Accounting and Reporting Standard* (this document, which provides a step-by-step guide for companies to use in quantifying and reporting their greenhouse gas emissions).
- *GHG Protocol Project Quantification Standard* (forthcoming; a guide for quantifying reductions from greenhouse gas mitigation projects).

There are three scopes of emissions that are established for greenhouse gas accounting and reporting purposes, defined as follows.

2.1 Scope 1 Emissions – Direct GHG Emissions

The GHG Protocol defines Scope 1 emissions as those which result from activities under the Proponent's control or from sources which they own. For the Longwall Project, the Scope 1 emissions are principally a result of the following activities.

- Generation of electricity, heat or steam. These emissions result from the combustion of fuels in stationary sources, eg boilers, furnaces or turbines. Such emissions are not expected to result from the Stage 2 operations.
- Physical or chemical processing. The majority of these emissions result from the manufacture or processing of chemicals and materials eg the manufacture of cement, aluminium, adipic acid and ammonia, or waste processing. Such emissions are not expected to result from the Stage 2 operations.
- Transportation of materials, products, waste, and employees. These emissions result from the combustion of fuels in company owned/controlled mobile combustion sources (eg trucks, trains, ships, airplanes, buses, and cars). These emissions have been quantified for the Stage 2 operations.
- Fugitive emissions. These emissions result from intentional or unintentional releases, eg equipment leaks from joints, seals, packing, and gaskets; carbon dioxide and methane emissions from coal mines and venting; hydrofluorocarbon (HFC) emissions during the use of refrigeration and air conditioning equipment;

and methane leakages from gas transport. These emissions have been quantified for the Stage 2 operations.

2.2 Scope 2 Emissions – Electricity Indirect GHG Emissions

Scope 2 emissions are those which relate to the generation of purchased electricity consumed in owned or controlled equipment or operations. For many companies, purchased electricity represents one of the largest sources of GHG emissions and the most significant opportunity to reduce these emissions.

2.3 Scope 3 Emissions – Other Indirect GHG Emissions

The GHG protocol states that Scope 3 reporting is optional and covers all other indirect GHG emissions. Scope 3 emissions are defined as those which do not result from the activities of a company although arise from sources not owned or controlled by the Proponent. Examples of Scope 3 emissions include the extraction and production of purchased materials, transportation of purchased fuels and the use of sold products and services.

In the case of the coal mining industry, Scope 3 emissions may include the transportation of sold coal and the use of this coal, either in Australia or overseas.

The GHG protocol flags the issue that the reporting of Scope 3 emissions may result in the double counting of emissions. A second problem is that as their reporting is optional, comparisons between countries and / or projects may become difficult. The GHG protocol also states that compliance regimes are more likely to focus on the "point of release" of emissions (direct emissions) and / or indirect emissions from the use of electricity. However, for GHG risk management and voluntary reporting, double counting is less important.

3 NATIONAL GREENHOUSE AND ENERGY REPORTING ACT

The National Greenhouse and Energy Reporting Act (the NGER Act) was passed on 29 September 2007, establishing a mandatory reporting system for company greenhouse gas emissions and energy production and consumption.

The first reporting period under the Act commenced on 1 July 2008.

The NGER Act seeks to provide a national framework for the reporting of greenhouse gas emissions, abatement actions, energy consumption and production by corporations. The data generated under the Act will lay the foundation for Australia's Carbon Pollution Reduction Scheme and assist Australia to meet its relevant international reporting obligations.

From 1 July 2008, corporations are required to register and report for the 2008 – 2009 financial year where they exceed the reporting thresholds. There are two levels of thresholds at which corporations or enterprises are required to apply for registration and report, namely, facility thresholds and corporate thresholds, as follows:

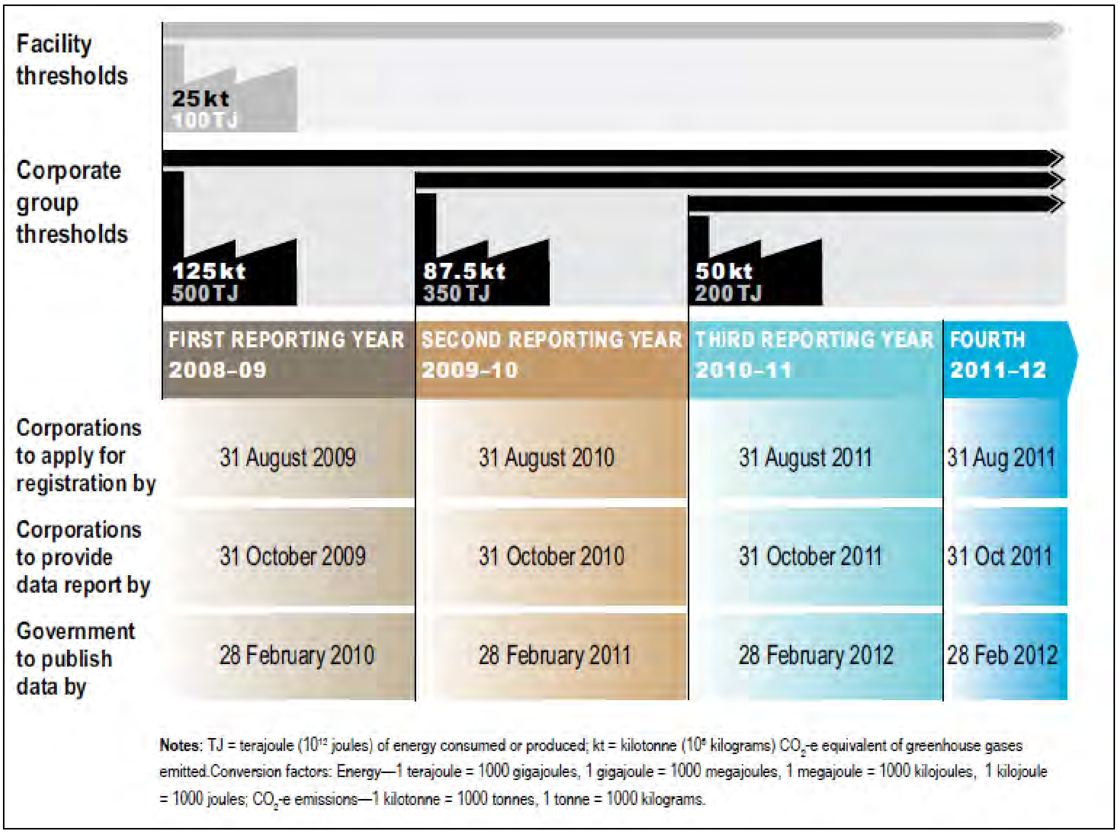
- They control a **facility** that emits 25 kilotonnes (kT) or more of greenhouse gases (CO_2 equivalent), or produces or consumes 100 Terajoules (TJ) or more of energy.

- Their **corporate group** emits 125kT or more greenhouse gases (CO_2 equivalent), or produces or consumes 500TJ or more of energy.

When a controlling corporation's group meets a facility or corporate threshold, the controlling corporation must apply for registration and report its greenhouse gas emissions and energy data to the Greenhouse and Energy Data Officer.

The corporate group threshold progressively reduced into the second and third reporting year, as outlined in **Figure 1**.

Figure 1
NGER Reporting Thresholds



Source: NGER Reporting guidelines

The National Greenhouse and Energy Reporting Guidelines have been developed to help corporations understand their obligations. The Reporting Guidelines are applicable across industry sectors and cover important concepts under the Act and Regulations, including scheme participation, determining corporate, facility and operational control, registration and reporting obligations. The National Greenhouse and Energy Reporting (Measurement) 2008 provides methods and criteria for calculating greenhouse gas emissions and energy data under the act.

The range of emission sources covered in the Determination include:

- The combustion of fuels for energy
- Fugitive emissions from the extraction of coal
- Oil and gas

- Industrial processes (such as producing cement and steel)
- Waste management

Reporting under the NGER is required for Scope 1 emissions and Scope 2 emisisons, while reporting of Scope 3 emissions is voluntary. The methods are based on those used for the National Greenhouse Accounts (refer **Section 5**).

3.1 Relevance to NCOPL Operations

NCOPL will be required to report under the NGER Act as the Longwall Project will emit more than 25kt of CO_2-e per year, mainly as a result of fugitive emissions (see **Section 7**).

4 CARBON POLLUTION REDUCTION SCHEME

In December 2008, the Australian Federal Government published a white paper outlining its intention to commence a Carbon Pollution Reduction Scheme on the 1 July 2010. The white paper (*Carbon Pollution Reduction Scheme - Australia's Low Pollution Future*) sets the policy framework for achieving a medium term emission reduction target and the means to achieve this reduction through the Carbon Pollution Reduction Scheme.

The government is committed to achieving a long term reduction target of 60% (from 2000 levels) by 2050. The white paper commits to an emission reduction target of between 5% and 15% by 2020. A 5% reduction is outlined as the minimum to be achieved while the 15% target is a commitment to reduce in line with the global agreements, should they come in force during this period.

The Carbon Pollution Reduction Scheme (CPRS) will employ a “cap and trade” mechanism, whereby GHG emissions are capped at a level and emitters will have to acquire and trade permits for every tonne of GHG gas emitted.

The threshold for participation in the CPRS is a facility that has direct (scope 1) emissions of 25,000 tonnes of CO_2-e a year or more. Indirect or ‘Scope 2’ emissions from electricity usage will not be covered.

The quantity of emissions produced will be monitored, reported and audited (through NGERS). Emitters of GHG need to acquire a permit for every tonne of greenhouse gas that they emit and at the end of the year, surrender a permit for every tonne of emissions produced in that year. Firms will compete on the open market to purchase the permits they require.

The cap sets a limit on the aggregate annual emissions from all types and sources of emissions that are covered by the scope. The number of tradable permits will be equal to the CPRS cap, for any compliance period. Entities responsible for emissions covered by the CPRS will have to surrender a permit for every tonne of CO_2-e that they emit during the compliance period. There is no cap on an individual company or facility, they are free to emit as such as they wish, provided they surrender an eligible permit for every tonne emitted. Permits will be tradeable with the price determined by the market.

The CPRS covers all six greenhouse gases that are covered by the Kyoto protocol, carbon dioxide, methane, nitrous oxide, sulphur hexafluoride, hydrofluorocarbons and perfluorocarbons.

4.1 Relevance to NCOPL Operations

The CPRS will cover mining operations where an individual facility exceeds the emission threshold of 25kt of CO_2-e per annum. For coal mining this will primarily be from fugitive emissions of methane.

While all direct emissions will count towards the facility-level threshold, entities may not be required to surrender permits for all their direct emissions in all circumstances. For example, emissions from the combustion of petroleum products will generally be covered by upstream fuel suppliers.

Large fuel users (where the combustion of fuel alone is responsible for over 25kt of CO_2 -e) will be able to use an obligation transfer number (OTN) to 'take-on' liability for fuel emissions. The advantage of managing scheme obligations directly means the supply of fuel will exclude an additional carbon price. In other cases, liability stays with the upstream fuel supplier.

Scheme obligations for emissions from black coal combustion would be applied to all coal mines, distributors, washeries, and producers of coke and coal by-products for emissions from small emitters. Similar to fuel suppliers, certain suppliers and users of coal may use an OTN to purchase fuel and directly manage any associated permit liabilities.

Entities reporting fugitive emissions from underground coal mines will be required to use National Greenhouse and Energy Reporting System Methods 1–4 for the estimation of emissions under the Scheme.

4.1.1 Funding Opportunities for Coal Mining

The Government will establish a $2.15 billion Climate Change Action Fund over five years to assist certain businesses, sectors and communities. An additional $300 million will be provided as part of the coal adjustment stream.

Coal mine operations with high fugitive emissions have been identified as an industry sub-sector that will not be eligible for other forms of CPRS assistance. Adjustment assistance of up to $250 million over 5 years will be provided to affected coal mining operators to promote emissions abatement and a further $500 million over five years will be provided as direct assistance to gassy coal mines to assist them adjust while they explore abatement opportunities.

5 NATIONAL GREENHOUSE ACCOUNTS (NGA) FACTORS

The Federal Department of Climate Change has prepared the National Greenhouse Accounts (NGA) *Factors* (November 2008) which replaces the previously used Australian Greenhouse Office (AGO) Factors & Methods Workbook.

The NGA *Factors* are used to estimate greenhouse gas emissions for reporting under various government programs, including the NGERS. The methods described for calculating emissions listed in the NGA Factors are "Method 1" from the National Greenhouse and Energy Reporting (Measurement) Determination 2008 and the National Greenhouse and Energy Reporting (Measurement) Technical Guidelines 2008 v1.1, which have been designed to support reporting under the National Greenhouse and Energy Reporting Act 2007.

The methods described for deriving emissions in the NGA factors are consistent with international guidelines (such as the GHG Protocol).

6 DRAFT GUIDELINES FOR ENERGY AND GREENHOUSE IN EIA

The Draft NSW EIA Guidelines were prepared in August 2002 by the NSW Sustainable Energy Development Authority (SEDA) and Planning NSW (now the Department of Planning (DoP)). The guidelines state that they are an advisory document and should principally be applied to projects which require an EIS under Part 4 and Part 5 of the Environmental Planning and Assessment Act 1979 (NSW) but can also be used for the assessment of other projects such as the Stage 2 Longwall Project which is being assessed under Part 3A of the EP&A Act.

The Draft NSW EIA Guidelines define four scopes of emissions, the first three being adopted along the lines of the GHG Protocol with the fourth relating to emission abatement.

On the basis of recent (significant) development in greenhouse gas reporting and emission estimation, the Draft Guidelines are not considered further in this report.

7 GREENHOUSE GAS ESTIMATES

For comparative purposes, non-CO_2 greenhouse gases are awarded a "CO_2-equivalence" based on their contribution to the enhancement of the greenhouse effect. The CO_2-equivalence of a gas is calculated using an index called the Global Warming Potential (GWP). The GWPs for a variety of non-CO_2 greenhouse gases are contained within the Intergovernmental Panel on Climate Change (IPCC) document *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*.

The GWPs of relevance to this assessment are:

- Methane (CH_4): GWP of 21 (21 times more effective as a greenhouse gas than CO_2); and
- Nitrous Oxide (N_2O): GWP of 310 (310 times more effective as a greenhouse gas than CO_2).

The short-lived gases such as CO, NO_2, and non-methane volatile organic compounds (NMVOCs) vary spatially and it is consequently difficult to quantify their global radiative forcing impacts. For this reason, GWP values are generally not attributed to these gases nor have they been considered further as part of this assessment.

The GHG Emissions associated with the Longwall Project have been assessed, in accordance with the DGRs, in terms of direct (Scope 1) emission potential, indirect (Scope 2 emission potential and significant upstream / downstream (Scope 3) emission potential.

7.1 Scope 1: Direct Emissions

7.1.1 Fugitive Emissions – Coal Bed Methane and Carbon Dioxide

The process of coal formation creates significant amounts of methane (CH_4). This CH_4 remains trapped in the coal until the pressure on the coal is reduced, which occurs during the coal mining process. The stored CH_4 is then released to the atmosphere.

The amount of CH_4 released during coal mining varies considerably as a function of factors such as the coal rank and depth, gas content, excavation methods and moisture levels (IPCC, 1996). As such, there are inherent uncertainties that must be considered when using estimates of CH_4 emission factors for coal excavation.

A proportion of the total CH_4 emitted from coal mining is generated during post-excavation activities such as coal processing and transportation. The processing of coal, including breaking, crushing and thermal drying, increases the surface area of the coal resulting in an increased rate of adsorption. CH_4 is desorbed during the transportation of coal as a result of direct exposure of the coal to air (IPCC, 1996).

The annual emissions of CH_4 and CO_2 from this source have been estimated based on the findings of exploration drilling results, which indicate that the underground workings would be expected to intercept a maximum of approximately $5m^3/t$ to $7m^3/t$ of gas during the mining operation. This gas would consist of approximately 90% CO_2 and 10% methane CH_4. Density of each gas has been calculated to 25°C and 1013hpa.

Emissions of CO_2-e have also been calculated based on emission factors for gassy underground mines (>0.1% CH_4 in mine return ventilation) taken from the NGA Factors Workbook (2008).

A report for the Stage 2 Narrabri Coal Project states that it is likely that the methane concentration in ventilation reporting to the main exhaust shafts will be less than 0.3% CH_4 for most, but not all of the mining area (based on information provided by NCOPL)).

Calculation Method 1 – Emission Factor

The emission factor for the extraction of coal (fugitive) from underground mines is provided in Table 6 of the NGA Factors Workbook (2008). Method 1 is provided in the NGER (measurement) determination 2008 technical guidelines as follows:

$$E_j = Q \times EF_j$$

where:

E_j = the fugitive emissions of methane (***j***) that result from the extraction of coal from the mine during the year measured in CO_2-e tonnes

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

EF_j = the emission factor for methane (***j***), measured in CO_2-e tonnes per tonne of run-of-mine coal extracted from the mine, as follows:

(a) for a gassy mine — 0.305;

(b) for a non-gassy mine — 0.008.

Annual ROM coal produced at the Mine Site has been provided and the emission factor above applied. Results based on the proposed annual production schedule are presented in **Table 1**.

Table 1
Proposed Coal Production Schedule & Calculated CO_2-e Emissions using NGERS Method 1

Year	Proposed Coal Production (Mt)	Calculated CO_2-e Emissions (Mt)
1	0.06	0.02
2	0.59	0.18
3	6.64	2.02
4	6.63	2.02
5	6.62	2.02
6	6.62	2.02
7	6.62	2.02
8	6.62	2.02
9	6.54	1.99
10	7.19	2.19
11	6.43	1.96
12	6.43	1.96
13	6.43	1.96
14	6.64	2.03
15	6.47	1.97
16	7.07	2.16
17	6.62	2.02
18	6.43	1.96
19	6.43	1.96
20	6.43	1.96
21	6.43	1.96
22	6.43	1.96
23	6.43	1.96
24	7.07	2.16
25	6.62	2.02
26	6.35	1.94
27	5.32	1.62
28	6.13	1.87
TOTAL	**170.26**	**51.93**
Note: Emission factors take into consideration emissions of methane only		

An average of 1.85Mt CO_2-e is calculated to be produced by the release of coal seam gas. In high production years (eg years 10 and 16), emissions are calculated to reach 2.19 Mt CO_2-e per annum. Emissions of CO_2-e over the mine life have been calculated to be 51.93 Mt. Emissions of CO_2-e for an 8Mtpa mining scenario would be 2.44 Mt.

Calculation Method 2 – Direct Measurement of Emissions

Chapter 3 of the NGER (measurement) determination 2008 technical guidelines details the use of direct measurements of coal mine waste gas and subsequent CO_2-e emission determination (Method 4).

$$E_j = CO_2 - e_{jgen,total} - \gamma_j (Q_{ij,cap} + Q_{ij,flared} + Q_{ij,tr})$$

where

E_j = the fugitive emissions of methane (***j***) that result from the extraction of coal from the mine during the year measured in CO_2-e tonnes

$CO_2 - e_{jgen,total}$ = total mass of gas type (***j***) generated from the mine during the year before capture and flaring is undertaken at the mine, measured in CO_2-e tonnes and estimated using the direct measurement of emissions in accordance with subsection (2) of the NGER (measurement) determination.

γ_j = factor for converting a quantity of gas type (***j***) from cubic metres at standard conditions of pressure and temperature to CO_2-e tonnes, being:

(a) for methane — $6.784 \times 10^{-4} \times 21$; and

(b) for carbon dioxide — 1.861×10^{-3}.

$Q_{ij,cap}$ = the quantity of gas type (***j***) in coal mine waste gas type (***i***) captured for combustion from the mine and used during the year, measured in cubic metres and estimated in accordance with Division 2.3.6 of the NGER (measurement) determination.

$Q_{ij,flared}$ = the quantity of gas type (***j***) in coal mine waste gas type (***i***) flared from the mine during the year, measured in cubic metres and estimated in accordance with Division 2.3.6 of the NGER (measurement) determination.

$Q_{ij,tr}$ = the quantity of gas type (***j***) in coal mine waste gas type (***i***) transferred out of the mining activities during the year measured in cubic metres.

Assuming that no gas is to be flared, captured for combustion or transferred out of the mining activities, an estimation of the quantity of CO_2-e from fugitive emissions of coal seam gas can be made.

A report prepared for NCOPL examines the pre-drainage, vent, goaf drainage and surface stockpile emissions of CO_2 and CH_4 during each longwall mining campaign. A total volume of CO_2 and CH_4 has been obtained for each of the emission sources and, using the equation above a total mass of CO_2-e has been calculated for the entire mine life. From this, an average annual emission of CO_2-e has also been calculated.

The report prepared for NCOPL is included as **Appendix 1** to this report.

Table 2
Calculated Emissions of CO_2-e based on Coal Seam Gas Assessment (based on information provided by NCOPL) using NGERS Method 4

Source	CO_2 (Mm^3)	CH_4 (Mm^3)	CO_2-e (Mt)
Pre-Drainage	330	126	2.42
Total Vent	640	202	4.09
Goaf Drainage	150	58	1.11
Surface Stockpiles	403	152	2.93
Total	**1,523**	**538**	**10.56**
Annual Total (assumed 30 year mine life)	**50.77**	**17.93**	**0.35**

7.1.2 Emissions Associated with Mine Decommissioning

Although emissions of CO_2-e associated with decommissioned underground mines are not liable under the CPRS, the DGRs require that an assessment of GHG emissions associated with any decommissioning activities be reported. Emissions of GHG to the atmosphere occur through fractured rock strata, open vents and seals over daily to decadal timescales. However, emissions can be reduced by flooding of the mine, which prevents desorption of gases from the remaining coal strata and non-coal strata layers in the closed mine.

The assessment of CO_2 and CH4 emissions from decommissioned underground mines is detailed within Section 3.2.4. of the NGER (measurement) determination 2008.

NGERS Method 4 (direct measurement) of CO_2 and CH_4 can be carried out as for an operational mine. Emission factors (NGERS Method 1) can be applied to derive the methane emissions from a decommissioned mine. These equations require a number of variables (eg mine void volume, rate of water flow into the mine).

Such information is not readily available at this time and therefore, accurate estimations of emissions from the decommissioned mine cannot be calculated. NCOPL will undertake a more detailed assessment once more operational and forecast information is known. Such information will for part of an ongoing greenhouse gas management and minimisation plan.

7.1.3 Diesel Usage

Scope 1 GHG emissions attributable to diesel relate to the use of on site machinery (including on-site transportation of coal product).

The primary fuel source for the vehicles operating on site would be Automotive Diesel Oil (ADO). Data is available on the diesel consumption for all mobile and fixed equipment servicing the site, and is estimated as 3284kL in year one of mining and 2022kL/year in ongoing years (2-30).

The annual emissions of CO_2 and other greenhouse gases from this source have been estimated using the NGA Factors Workbook (2008). It has been assumed that the energy content of ADO is 38.6MJ/L (ABARE, 2004).

Table 3
Calculated CO_2-e Emissions from Diesel Usage on-site

Year	Diesel Usage (kL)	CO_2-e emissions (tonnes)
1	3,284	8,860
2-30	2,022	5,456
Total	61,922	167,074

7.1.4 Explosives

The use of explosives in mining leads to the release of greenhouse gases. The activity level is the mass of explosive used (in tonnes). Emissions factors are available for the three main types of explosives (Ammonium Nitrate with Fuel Oil (ANFO), Heavy ANFO and Emulsion).

It is currently anticipated that it will be unlikely that explosives will be used on site during the operation of the Longwall Project and if so (for shaft construction) their use would be minimal. As a consequence, these emissions have not been included within this assessment.

7.2 Scope 2: Indirect Emissions through the consumption of Purchased Electricity

The production of electricity by on-site power generating equipment is covered in Scope 1 GHG emissions. Scope 2 GHG emissions relate to the consumption of purchased electricity. The NGA Factors Workbook gives state emission factors for both Scope 2 and Scope 3 consumption of purchased electricity.

State emission factors are used because electricity flows between states are significantly constrained by the capacity of the inter-state interconnectors and in some cases there are no interconnections.

The emission factor for Scope 2 covers emissions from fuel combustion at power stations associated with the consumption of purchased electricity. The Scope 3 emission factor covers both the emissions from the extraction, production and transport of fuels used in the production of the purchased electricity (ie fugitive emissions and stationary and mobile fuel combustion emissions) and also the emissions associated with the electricity lost in transmission and distribution on route to the customer. In this report, Scope 2 and 3 emissions for the consumption of purchased electricity have been reported separately so that the share of the transport and distribution loss can be correctly attributed under Scope 3 emissions – Generation of Electricity Consumed in a Transmissions and Distribution (T & D) System.

Projected electricity use at the Mine Site has been provided by NCOPL for years 2009 to 2018 (see **Table 4**).

Table 4 Projected Electricity Consumption for the Narrabri Longwall Project 2009-2018

Year	Electricity Usage (MWh)
2009	11,429
2010	21,180
2011	48,184
2012	48,184
2013	48,184
2014	48,184
2015	48,184
2016	48,184
2017	49,283
2018	49,283

It can be seen from **Table 4** that the maximum electricity consumption occurs in years 2017 and 2018. It has been assumed that the electricity consumption in these years is ongoing to the end of the Longwall Project lifetime. Therefore, total electricity consumption over the Longwall Project lifetime of 30 years has been calculated to be 1,405,939MWh. As a worst case assumption, the annual electricity consumption has been assumed to be 49,283MWh.

7.3 Scope 3: Other Indirect Emissions

7.3.1 Use of Products Manufactured and Sold

Indirect emissions of GHG from the combustion of product coal are expected “downstream” due to the extraction activities at the Narrabri Coal Mine. Up to 8Mt of coal annually are expected to be produced by this mine, with the majority destined for international markets.

The GHG emissions from combustion of product coal have been based on a coal energy content of 27GJ/t (Table 1 of the NGA Factors Workbook, 2008). Standard emission factors for Scope 1 emissions from coal combustion have been taken from Table 1 of the NGA Factors Workbook (2008).

7.3.2 Employees Commuting to and from Work

Fuel usage and consequent GHG emissions attributable to company employees commuting to and from work can be reported under Scope 3 GHG emissions. Fuel consumption rates by employees have been assumed to be 7L/100km. Assumptions regarding the fuel types and distances travelled by each employee are made where specific information is not available.

Employee vehicles are assumed to be in the category of Passenger Cars and use Automotive Diesel Oil (ADO). Distance travelled to and from work per employee is calculated based on the radius of the distance from the Mine Site to the closest habitation(s) of significance (Narrabri, approximately 30km). It has been assumed that 186 personnel will be employed at the mine during the Longwall Project and all staff will drive to work from Narrabri. Diesel consumption from this component is estimated to be approximately 285kL per annum resulting in CO_2-e emissions of 768 tonnes per annum (Scope 3).

7.3.3 Extraction, Production and Transport of Purchased Fuels Consumed

See **Section 5.3.1**.

7.3.4 Extraction, Production and Transport of other Purchased Materials or Goods

GHG emissions relating to the extraction, production and transport of other purchased materials or goods such as raw materials in the production of concrete, for example should be reported here. In addition, if any other fuels are consumed on site, such as natural gas, the emissions should be reported both in Scope 1 emissions (direct emissions) and under this heading in Scope 3 relating to the extraction, production and transport of the fuel. In terms of the Longwall Project, no significant items relate to this category.

7.3.5 Generation of Electricity Consumed in a Transmission and Distribution System

See Section 5.2.1.

7.3.6 Transportation of Products, Materials and Waste

Transportation of product coal from the site of mining to the site of combustion will generally involve transport via road, rail and / or boat. Transport of 100% of the product coal from the mine site to its international distribution point at Port Newcastle is expected to occur.

Transport via Rail

An average of approximately 35 trains carrying 5,400 tonnes of coal each are assumed to be despatched from the Narrabri coal loader per week to Port Newcastle, approximately 382km to the southeast. Information provided for a previous Heggies greenhouse gas assessment for a mine near Gunnedah identified that product trains to Newcastle consumed 0.015 litres of diesel per tonne of coal transported each kilometre. This results in an annual diesel consumption of 56.5ML.

It is considered that Scope 3 emissions in the category “extraction, production and transport of purchased fuels consumed” will be sufficient to encompass the full life cycle of the product coal from extraction to ultimate combustion.

Table 5
Annual Greenhouse Gas Emissions – Narrabri Longwall Project

ROM Production (tonnes)	Saleable Coal (tonnes)	Emissions Source	Usage			Total Use	Units	Emission Factors			Emissions (t CO_2-e)			Total (t CO_2-e)[1]
			Scope 1	Scope 2	Scope 3			Scope 1	Scope 2	Scope 3	Scope 1	Scope 2	Scope 3	
8,000,000	8,000,000	Seam CH_4	8,000,000[3]			8,000,000	tonnes	0.305			2,440,000			**2,440,000[5]**
		Seam CH_4	*17,930,000[4]*			*17,930,000*	*m^3*	*0.014*			*257,954*			*257,954[6]*
		Seam CO_2	*50,766,000[4]*			*50,766,000*	*m^3*	*0.0018*			*94,477*			*94,477[6]*
		Diesel	2,022[2]		58,807	60,829	kL	2.7		0.21	5,459		12,774	18,233
		Explosives	0			0	tonnes	0.1673			0			0
		Electricity		49,283	49,283	49,283	MWh		0.89	0.17		43,861	8,378	52,239
		Coal			8,000,000	8,000,000	tonnes	2.38					19,051,200	19,051,200
TOTAL														**19,474,103**

Note 1: t CO_2-e - tonnes of CO_2 equivalent
Note 2: Onsite diesel use provided for year all years. Year 2+ presented here
Note 3: Based on gassy mine emission factor for ROM coal
Note 4: Based on direct measurements of vent gas equation (based on information provided by NCOPL)
Note 5: Calculate using Method 1 emissions estimates (emission factor) Not used in calculation of total
Note 6: Calculated using Method 4 emissions estimates (direct measurement)

Table 6
Total Greenhouse Gas Emissions – Narrabri Coal Project (Potential Project Total – 30 Year Mine Life)

ROM Production (Mtonnes)	Saleable Coal (Mtonnes)	Emissions Source	Usage			Total Use	Units	Emission Factors			Emissions (Mt CO_2-e)			Total (Mt CO_2-e)[1]
			Scope 1	Scope 2	Scope 3			Scope 1	Scope 2	Scope 3	Scope 1	Scope 2	Scope 3	
170.255	170.255	Seam CH_4	170.255[3]			170.255	Mt	0.305			51.93			**51,928[5]**
		Seam CH_4	*538[4]*			*538*	*Mm^3*	*0.014*			*7.72*			*7.72[6]*
		Seam CO_2	*1,523[4]*			*1,523*	*Mm^3*	*0.0018*			*2.83*			*2.83[6]*
		Diesel	61.9[2]		1,703.	1,765	ML	2.7		0.21	0.17		0.36	0.53
		Explosives	0			0	tonnes	0.1673			0			0
		Electricity		1,405,939	1,405,939	1,405,939	MWh		0.89	0.17		1.25	0.24	1.49
		Coal			170.255	170.255	Mtonnes	2.38					405,206	405,206
TOTAL														**405,218**

Note 1: Mt CO_2-e – million tonnes of CO_2 equivalent
Note 2: Onsite diesel use provided for year all years
Note 3: Based on gassy mine emission factor for ROM coal
Note 4: Based on direct measurements of vent gas equation (based on information provided by NCOPL)
Note 5: Calculate using Method 1 emissions estimates (emission factor) Not used in calculation of total
Note 6: Calculated using Method 4 emissions estimates (direct measurement)

8 GREENHOUSE GAS MITIGATION

It can be seen from **Table 7** that there is a significant difference in the calculated CO_2-e emissions and associated costs between the emission estimation techniques based on NGERS Method 1 (emission factor) and Method 4 (direct measurement).

It is clear that the use of NGERS Method 1 is unsuitable as it is a generic emission factor which, based on preliminary studies, over estimates the emissions of CSG from the Mine Site.

The emissions calculated from fugitive releases of coal seam methane using NGERS Method 4 are based on preliminary studies (provided by NCOPL). It is envisaged that these estimations will not be sufficient to determine ultimate liabilities under the CPRS.

The dominant direct (Scope 1) sources of GHG emissions associated with the Longwall Project are coal seam methane emissions are calculated to be 0.35 Mt CO_2-e per year and 10.55 Mt CO_2-e over the Longwall Project lifetime.

As recognised in preliminary studies (provided by NCOPL), the potential CO_2-e charge associated with pre- and goaf-drained methane will, if preliminary studies are representative, be significant.

Based on the calculations above and an assumed cost per tonne of CO_2-e of $25 under the operation of the CPRS (see **Section 4**), the potential liable cost to NCOPL for coal seam methane is presented in **Table 7**.

Table 7
Potential Liable Costs to NCOPL under the CPRS – Fugitive Coal Seam Emissions Only

Timeframe	Emission Factor	Emission CO_2-e (Mt)	Potential Liable Cost (AU$M)
Annual	NGERS Method 1	2.4	60.00
	NGERS Method 4	0.35	8.75
Project Lifetime	NGERS Method 1	51.93	1,298.25
	NGERS Method 4	10.55	263.75

It can be seen from **Table 7** that a significant amount of expenditure may be required by NCOPL under the CRPS. This raises the possibilities of investigating methods for reducing this potential liability.

8.1 Direct Measurement of Emissions

NGERS Method 4 provides for direct measurement of greenhouse gas emissions. Two systems for the direct monitoring of emissions are available:

- Continuous Emissions Monitoring (**CEM**)
- Periodic Emissions Monitoring (**PEM**)

Details of the structure and design of any emissions monitoring system is provided in Part 1.3 of the NGERS (Measurement) Guidelines. Detail on the measurement of CO_2 and CH_4 from underground mines is provided in Part 3.2.2 of the NGERS (Measurement) Guidelines.

Consideration of installation of a CEM or PEM at the Mine Site is strongly recommended.

8.2 Capture and Flaring of Coal Seam Gas

Emissions of coal seam gas can be captured and combusted/oxidised or flared. These methods can act to reduce the emissions of CO_2-e assigned to the Project.

8.2.1 Capture and Combustion/Oxidation

Use of ventilation air methane (VAM) is generally challenging due to the large airflows and low methane concentrations (typically 0.1 to 1%). The oxidation of methane produces heat, which can be used to produce electricity, hot water, steam and hot air.

Thermal or catalytic oxidation VAM units destroy methane in concentrations from about 0.3% to 0.9% CH_4 (Source – NCOPL). The units can manage about 17m^3/s of gas mixture and cost about AU$M 1.5 capital to purchase with ongoing power consumption of about 200 kW (AU$87,000 per year). It is technically feasible to install one or more of these units to destroy methane in captured gas streams using appropriate intake dilution and additional heater energy to overcome damping effects of carbon dioxide. For example, if 1.0m^3/s of gas is being captured with a composition of 10% CH_4 and 90% CO_2 then an 11:1 dilution ratio would produce a gas mixture that could be passed through a VAM unit.

Manufacturer's specifications for such technologies state that up to 97% of the methane in the VAM can be oxidised to CO_2. As CH_4 has a global warming potential of 21 times that of CO_2, it is considered that such a technology would provide significant emissions reductions for the Stage 2 operations.

Quantification of actual emissions reductions requires a detailed breakdown of VAM constituents and quantities. Further research is to be conducted to determine whether one or more thermal oxidation units would be feasible for the Stage 2 operations. It is likely that the methane content in the ventilation air would be below the 0.3% CH_4 threshold for VAM units for most, but perhaps not all of the mining area. Further research is to be conducted by NCOPL to determine whether one or more VAM units would be feasible in the future.

8.2.2 Flaring

Flaring of methane from gassy mines can significantly reduce the CO_2-e emissions associated with venting. United Collieries have installed a mine gas collection system routed to three surface flares at their colliery near Singleton, NSW (NSW Minerals Council, 2007). Each flare has the capacity to reduce CO_2-e emissions by 125kt per annum.

The installation of flares requires a detailed risk assessment and installation of real-time monitoring equipment and safety measures to shut down flaring should critical temperatures or gas concentrations be exceeded.

It is considered that flaring of the methane associated with the Narrabri Project will not sufficiently reduce CO_2-e emissions to reduce potential liabilities under the CPRS. The additional income generated / saved from using VAM units would be a more attractive option.

8.3 Other Mitigation Measures

Other GHG mitigation and adaptation measures which aim to reduce the total greenhouse gas emissions from the Project are outlined below.

8.3.1 General

- Apply best practice to maximise energy efficiency and minimise emissions.
- Undertake analysis to identify and implement appropriate offsets.
- Carry out ongoing monitoring and reporting of greenhouse gas emissions and identify options and opportunities for reductions over time.

8.3.2 Relating to Diesel Consumption during Project Construction and Operation

- Optimise and schedule vehicle operations to reduce fuel consumption.
- Maintain engines according to manufacturer's guidelines and keep tyres at optimum pressure to maximise fuel efficiency.
- Reduce vehicle idling time.
- Consider the use of alternative fuels with a reduced carbon content, such as biodiesel, for mobile plant.

8.3.3 Regarding Electricity Consumption

- Implement solar-powered lighting about site where possible.

8.3.4 Regarding Employee Travel

- Encourage the use of a car pool scheme for employees travelling from Narrabri to reduce single occupancy car journeys.
- Provide buses to transport employees from Narrabri to the Mine Site.

The feasibility of all of the foregoing mitigation and minimisation options, including ongoing monitoring will be determined by NCOPL and will be included in a detailed greenhouse gas minimisation plan for the Project. Such a report will be a ‘living’ document with all findings incorporated as the Project progresses,

9 CONCLUSION

Estimates of direct and indirect GHG emissions attributable to the Narrabri Longwall Project have been assessed and reported. The most significant emissions are associated with fugitive emissions of coal seam gas through venting.

Estimates of CSG emissions have been made using two methods – emission factors and direct measurements. Estimates through the use of emission factors have predicted annual emissions of CO_2-e from CSG to be approximately 7 times greater than those predicted using direct measurements (from preliminary studies). It is likely that emissions estimates using data from the preliminary studies of CSG at the Mine Site will be more accurate than generic emission factors and therefore these have been used in the calculation of annual and Project total emissions and in comparison with National and State GHG emission totals.

Annual emissions of CO_2-e from the Narrabri Stage 2 Longwall Project have been calculated to be 19.5 Mt (Scope 1 – 3). Scope 1 (direct) emissions of CO_2-e are calculated to be 0.4 Mt per annum using the direct measurement method to derive coal seam emissions, and 2 Mt per annum using the emission factor for gassy underground mines.

Total emissions CO_2-e from the Project over the predicted 30 year mine life have been calculated to be 405 Mt (Scope 1 – 3). Scope 1 (direct) emissions of CO_2-e are calculated to be 10.7 Mt using the direct measurement method to derive coal seam emissions and 52 Mt per annum using the emission factor for gassy underground mines.

Due to the current uncertainty relating to GHG emissions and proposed mitigation measures to be employed, the comparison of the Project against best practice emissions for NSW underground coal mines is difficult. However, in the GHG minimisation plan, estimates of reductions and resulting emissions estimates will be compared with best practice.

9.1 GHG Reporting

Greenhouse gas estimates are assessed relative to 1990 baseline levels for reporting purposes. The *1990 National Greenhouse Gas Inventory* (AGO, 2008a) provides estimates of greenhouse emissions in Australia, given as 553.7 Mt CO_2-equivalent.

A comparison of the predicted direct (Scope 1) emissions with the 1990 national estimate demonstrates that operations would represent an annual increase of approximately 0.06 % of the total baseline Australian emissions, using the direct measurement method for coal seam methane, with the inclusion of coal combustion. Using the emission factor for gassy underground mines, this annual increase is calculated to be 0.36%.

Emissions of greenhouse gases in NSW during 2006 amounted to a total of 160.0 Mt CO_2-equivalent (AGO, 2008b). A comparison of the predicted emissions due to the proposed operations with NSW emissions in 2006 demonstrates that operations would represent an annual increase of approximately 0.3% using the direct measurement method for coal seam methane, with the inclusion of coal combustion. Using the emission factor for gassy underground mines, this annual increase is calculated to be 0.6%.

9.2 The NSW Greenhouse Plan

Published in November 2005, the NSW Greenhouse Plan is a strategic document which sets out the NSW Government's aims and initiatives in terms of greenhouse gas emissions abatement over the next 20 to 45 years. The NSW Government nominates that it would like to meet the following criteria:

- A 60% reduction in greenhouse gas emissions by 2050; and
- Cutting greenhouse gas emissions to year 2000 levels by 2025.

The NSW Greenhouse Plan does not set out a methodology for reporting greenhouse gas emissions, rather seeks to:

- Increase awareness among those expected to be most affected by the impacts of climate change.
- Begin to develop adaptation strategies to those unavoidable climate change impacts.
- Put NSW on track to meeting the targets set out above.

The Plan seeks to promote climate change partnerships by Government, individuals, industry, business and community groups. It is recommended that NCOPL seek to assess the opportunities under the Plan to gain funding or grants to reduce GHG emissions from the Narrabri Longwall Project.

The NSW Greenhouse Plan is due to be replaced with the NSW Climate Action Plan in mid 2009. In the interim period, the NSW Greenhouse Plan remains current government policy.

10 REFERENCES

- Australian Government Department of Climate Change (2008a), Australia's National Greenhouse Accounts, The Australian Government's Initial Report under the Kyoto Protocol
- Australian Government Department of Climate Change (2008b), Australia's National Greenhouse Accounts, State and Territory Greenhouse Gas Inventories 2006
- Australian Government Department of Climate Change (2008c), National Greenhouse Accounts (NGA) Factors Workbook, November 2008.
- Intergovernmental Panel on Climate Change (IPCC) (1996), Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories.
- World Business Council for Sustainable Development / World Resources Institute (2005), The Greenhouse Gas Protocol for Project Accounting

This page has intentionally been left blank

Appendix 1

Narrabri Project – Greenhouse Gas Emission Mitigation Strategy

(No. of pages excluding this page = 22)

Please note this appendix has been printed in black and white. A colour copy is available on the digital version of this report provided on CD.

This page has intentionally been left blank

Report on :	**Narrabri Project – Greenhouse Gas Emission Mitigation Strategy**
	DRAFT WORKING DOCUMENT
For :	**Palaris Mining Pty Ltd**
Reference :	**Michael Simes**
Prepared By :	**Roy Moreby**
Date :	**March 2009**

Table of Contents

List of Tables

List of Figures

Revision Status

Rev	Comment	Date
1	Draft for comment and review	29/03/09
2		
3		

1 INTRODUCTION

The purpose of this report is to provide an estimate of seam gas emissions from the Narrabri project over the life of mine using data available as of March 2009. The objective is to provide values for the mine's environmental impact statement and to estimate future CO_2-e emission charges.

1.1 Scope, Limitations and Assumptions

1. The mine area includes 26 longwall blocks to be extracted by a single longwall using conventional (not top coal caving) methods.

2. The seam will be pre drained from underground and or surface to mitigate the risk of outbursts and to reduce net longwall gas emission to enable two heading gate roads to be employed. The effectiveness of pre drainage in this carbon dioxide rich environment has not yet been proven.

3. Goaf post drainage will be employed to capture gas that would otherwise report to the longwall ventilation circuit. However, the effectiveness of goaf drainage may be compromised by spontaneous combustion management requirements.

4. All emission streams will be included, namely;
   - Gas reporting to ventilation
   - Pre and post drainage directly discharged to atmosphere
   - Emissions from stockpiles on surface
   - Post combustion gases if oxidation methods of destroying methane are employed.

5. Although general planning values are used in this report to estimate the distribution of total seam gas emission to these various streams, these values are not based on site specific data and must be treated as indicative only. They must also be reviewed as further seam characterisation data becomes available.

6. Seam gas composition and content data currently available is employed for this analysis although it is identified that there is very little data to confirm values for large parts of future mining areas, particularly to the west. In addition the size of the gas reservoir contained in other porous strata is unknown. At best, the results contained in this report must be treated as an orders of magnitude analysis

7. Pertinent GHG emission parameters are 1 tonne CH_4 = 21 tonne CO_2 –e, 1 tonne CO_2-e will be charged at AU$25.

2 CONCLUSIONS AND RECOMMENDATIONS

Based on work contained in this report the following conclusions and recommendations are made with respect to the mine's ventilation GHG mitigation strategy;

1. Subject to the identified limitations associated with the analysis of seam gas emission for the project with currently available data, the overall life of mine emission values are provided in Table 2.1. A block by block analysis is provided in section 4 of this report.

Table 2.1 Overall Mine CO_2-e Emission and Charges

	Emitted Volume Mm3	CO2-e Mt	Charge AU$M
Carbon dioxide	1523	2.83	71
Methane	538	7.67	192
		10.51	263

2. This demonstrates that the most significant issue will be fugitive methane emission, particularly to the west, if currently available gas composition contours remain representative.

3. The success of full seam (working section and immediate roof) pre drainage is essential for this project for both operational and GHG emission reasons. The various assumptions employed in this report should be reviewed once additional seam characterisation data, including MRD pre drainage trials, becomes available. However, peak longwall carbon dioxide and methane emission rates will be problematic in various parts of the mine if re and post drainage effectiveness is not sufficient. This conclusion is consistent with previous analysis.

4. It is technically feasible to destroy methane in captured gas streams using thermal or catalytic VAM units. Although, it is understood, that this strategy has not been employed elsewhere and would most likely attract R&D tax concessions if not grants from the Australian government's GHG abatement transitional fund.

   Based on results contained in this report, CO_2-e charges would reduce by about AU$44M over the life of mine if pre drained gas were employed and the average pre drained gas content were $5m^3/t$. Of course, savings would increase further with greater pre drainage effectiveness or if VAM units were to be applied to goaf drainage streams.

5. Once results of the MRD pre drainage trial are available, the overall gas drainage strategy should be reviewed, including surface reticulation of gas to centralised pump stations and, potentially, VAM units.

6. It is likely that he methane concentration in ventilation reporting to main exhaust shafts will be below the 0.3% CH_4 threshold for VAM units for most, but not all of the mining area. This again is subject to pre drainage effectiveness and actual gas composition to the west.

2.1 Future Work

1. Undertake MRD trial as planned, then review gas drainage strategy.

2. Increase gas reservoir data from western blocks, including assessment of porous strata i.e. porosity, water saturation and thickness.

3. Obtain long term desorption, rather than quick crush, data and native isotherms in order to quantify the true residual gas content of coal. This is required to improve prediction of goaf and stockpile emissions and hence the benefit of top coal caving.

4. Consider the work necessary to employ an initial VAM unit as an R&D project with possible additional funding being available from coal sector transitional funds.

3 GAS RESERVOIR CHARACTERISTICS

The purpose of this section is to define the mine design parameters and underlying assumptions employed in the calculation of seam gas emission over the life of mine. Seam thickness, depth of cover, seam gas content and gas composition contours employed are shown in Figure 3.2. It is however emphasised that contours to the west of the lease are based on a very limited number of exploration holes and these contours may not in fact be correct.

Pertinent characteristics of the Hoskissons seam are,;

1. Gas contents range nominally 3.5 to 7.5m^3/t with a poor direct relationship with depth as is typical for CO_2 rich seam gas reservoirs, Figure 3.1 (Williams, 2008). It is however important to note that due to the limited number of data points available for deeper horizons the scatter is currently weighted towards initial eastern blocks.

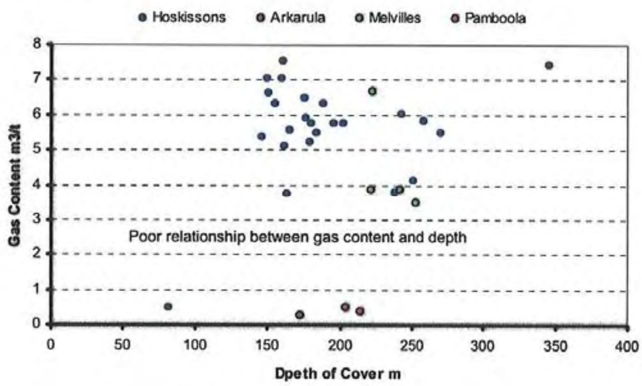


Figure 3.1 Gas Content – Depth of Cover Relationship

2. The seam gas composition is reported to contain significant "air free" nitrogen, Figure 3.3. However, a large fraction of this is likely to arise from oxygen depletion in the core canisters. For planning purposes and subject to further data becoming available, the seam gas composition is assumed to be an average 87% CO_2 and 13% CH_4 as is indicated by composition from higher gas content samples, Figure 3.4. However, it is important to recognise the variations that occur if the distribution indicated by gas composition contours is correct i.e. current averages are weighted by the location of samples available.

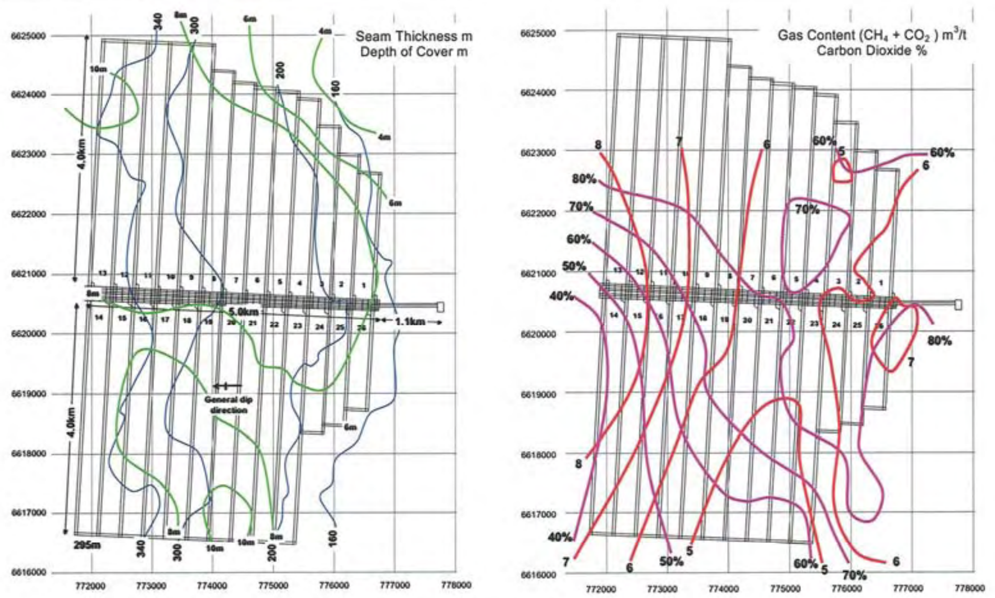


Figure 3.2 Seam Gas Content and Composition Data

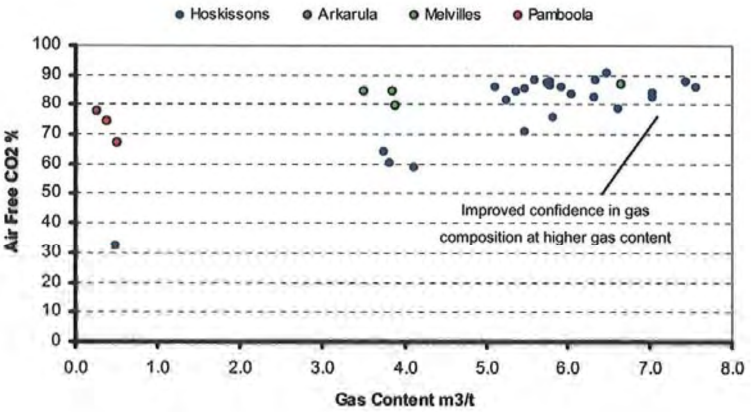


Figure 3.3 Gas Content – Air Free CO_2 Relationship

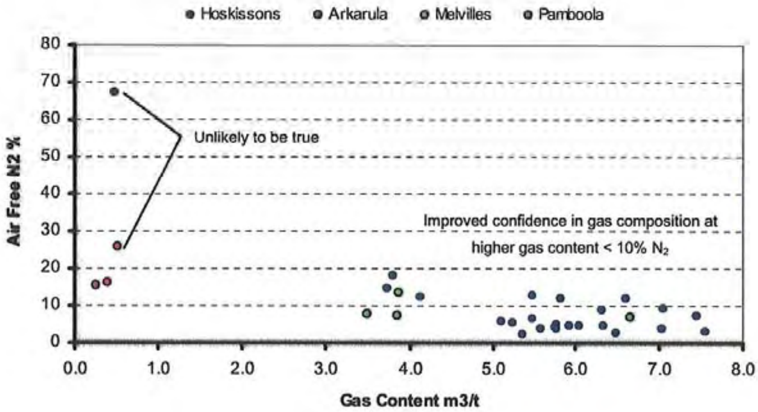


Figure 3.4 Air Free N_2 – Gas Content Relationship

3. With respect to the size of the gas reservoir, there are no seams above the Hoskissons and floor seams are some 50m or so from the working section. As with gas contents, there is limited data to confirm the thickness and spacing of seams and other strata members across the entire lease area. For the purpose of this report, gas contained in these remote floor seams is not included.

4. It is reported that coarse grained sandstones in the floor are relatively porous (possibly 10 to 15% porosity) and contain free gas. These could provide an additional significant source of gas that needs to be quantified in future exploration work. The most important issues are strata thickness and total unsaturated porosity. For the purpose of this report, an allowance of 20m porous strata is used but this is very speculative.

3.1 Fluid Pressure and Gas Saturation

Seam fluid pressures from permeability testing (Gray, 2008) are shown in Figure 3.5 from which the degree of gas saturation can be obtained, Figure 3.6.

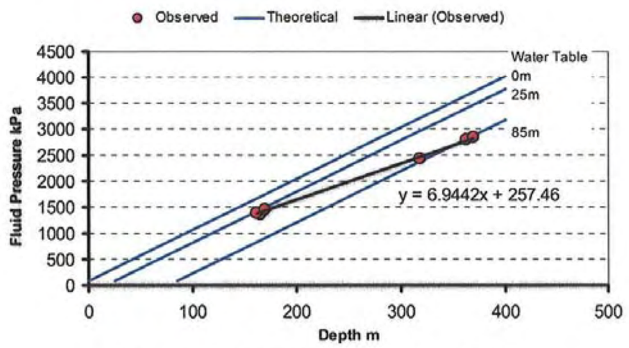


Figure 3.5 Seam Fluid Pressure (SIGRA data)

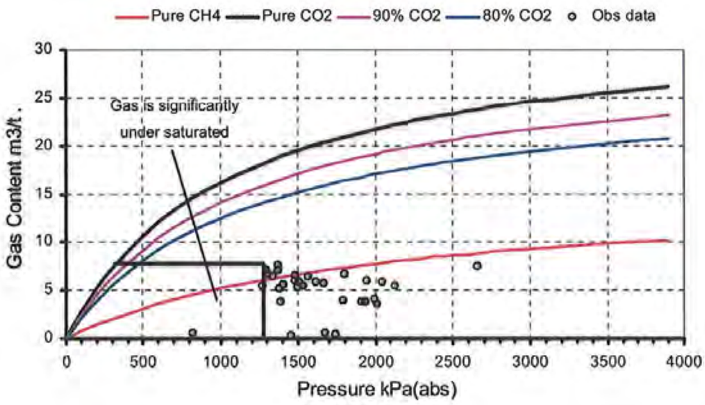


Figure 3.6 Isotherms and Observed Data

This indicates that the seam is very under saturated with significant fluid pressure reduction required for effective pre drainage. This data also indicates that long lead times (9 to 12 months) with holes at relatively close spacing (20 to 30m) will be required to achieve the reduction in seam gas contents necessary for outburst thresholds and reduction of rib emission. These pre drainage requirements will be re assessed once MRD trial data becomes available.

For the purpose of this report it is assumed that pre drainage will be employed but gas contents will only be reduced to $5m^3/t$ for outburst mitigation.

3.2 Gas Content of Interburden

Using the fluid pressures obtained from permeability testing, the **potential** gas content of porous interburden is shown in Figure 3.7.

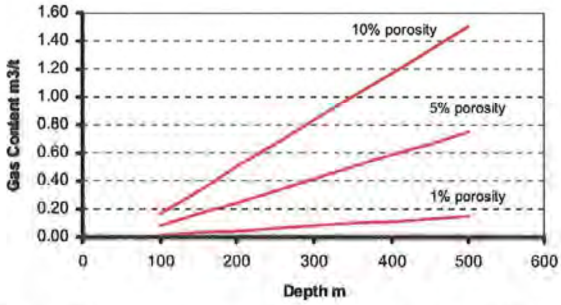


Figure 3.7 Potential Gas Content of Porous Interburden (RD 2.7t/m^3)

For example, a 5m thick sandstone member at 5% unsaturated porosity could contain 0.4m^3/t free gas or about 5.4m^3/m^2. This would equate to a specific gas emission rate of about 1.0m^3/t or 300l/s at a production rate of 6.0Mtpy (130,000 tpw).

It is recommended that future exploration and preliminary gas drainage work assess the thickness, porosity and gas content of interburden in order to quantify the gas reservoir present with more confidence. Without this information, gas emission rates could be significantly over or under estimated.

3.3 Gas Desorption Rates

Gas emission from production coal can be estimated using data from Q1 (lost gas) data, for example the data for a 8.1m^3/t sample (NA007) and a 4.8m^3/t sample (NA010) is shown in Figure 3.8.

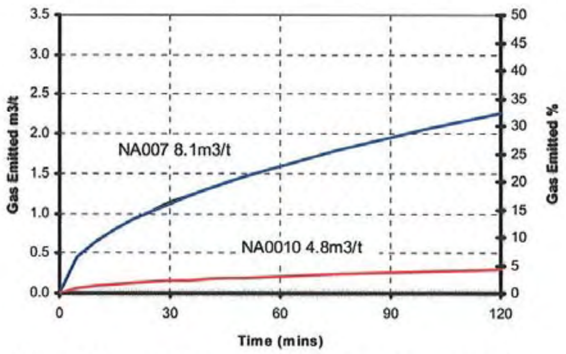


Figure 3.8 Gas Emission Rate From Core Sample (7.0m^3/t)

Assuming that cut coal desorbs gas in a similar manner to core samples, then an indication of the fraction of gas that would emitted in underground intake airways is shown in Table 3.1 using the that for NA007. It is a reasonable approximation to use the same percent lost relationships for other gas contents i.e. if 10% of 8m^3/t (0.7m^3/t) is lost in 15 minutes then so too would 10% of 7.0m^3/t (0.4m^3/t) . This is not true at lower gas contents but is appropriate for decision making at this stage i.e. will err on the side of caution for un drained coal.

Table 3.1 Residence Time and Gas Emission from Longwall Production Coal

	Section mins	Cumulative mins	Gas Emission %
Face	5	5	7
Gate road 4km	17	22	13
Mains 1km	4	26	15
Mains 2km	8	30	16
Mains 3km	13	34	16
Mains 4km	17	38	17
Mains 5km	21	43	19

Overall, this demonstrates that 80 to 85% of the gas in production coal would still be in the coal when it arrived at surface and hence not impose a load on the underground ventilation circuit. For lower gas contents the fraction emitted on surface would be even higher. It is for this reason that top coal caving would reduce the amount of gas to be managed underground.

For the purpose of this report an underground emission factor of 15% will be employed.

4 SEAM GAS EMISSION

Analysis in this section is aimed at providing estimates of gas emission volumes (m^3) for the purposes of calculating GHG emission impact for the mine's environmental impact statement. This is distinct from calculating gas emission rates (m^3/s) required for detailed design of gas drainage and ventilation systems. However, cognisance is made of expected ventilation and pre drainage capacities necessary to manage likely gas emission rates for compliance with general body gas concentrations i.e. to which stream will gas be emitted and therefore potentially mitigated.

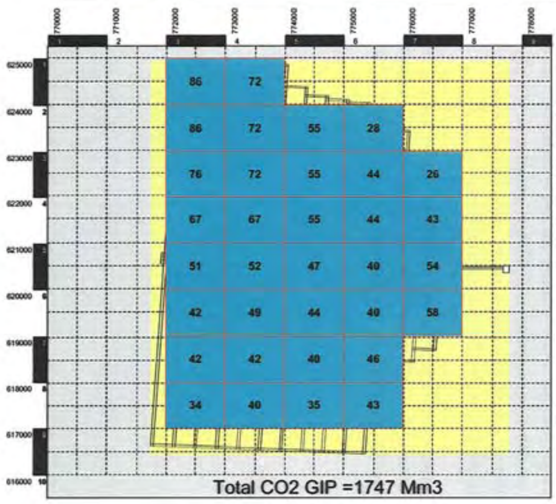
The approach taken is, subject to the identified assumptions in sections 1.1 and 3.0 above, to calculate the total gas in place in order to estimate gas emission to various points of discharge, being

1. Ventilation from development rib emission and longwall emission net of goaf drainage.
2. Pre drainage by underground or surface to in seam (SIS) holes
3. Goaf drainage
4. Surface stockpiles.

4.1 Total Gas In Place

For the purposes of this report, total gas in place (methane and carbon dioxide Mm^3) has been calculated for each 1km^2 grid block using the allocated seam thickness, gas content (at 15% ash) and gas composition. Coal seam gas composition is applied to porous strata (assumed 20m thick). The overall total gas in place is the sum of the value obtained for each grid block.

The total mining area is approximately 34km^2 with a total of 1,747 Mm^3 CO_2 and 624 Mm^3 CH_4 in seams and strata to be disturbed by mining, Figure 4.1 and 4.2. With consideration to the close proximity of roof coal and porous interburden, it can be assumed that this will be released, at least to residual gas contents.



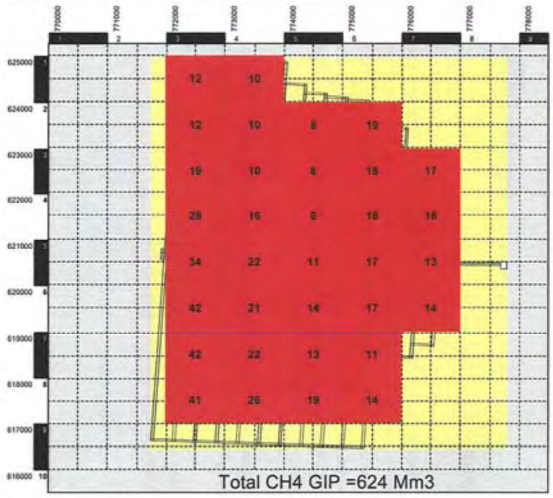


Figure 4.1 Gas in Place – Carbon Dioxide

Figure 4.2 Gas in Place – Methane

4.2 Gas Emission

Prior to further seam characterisation data being available, MRD trials in particular, it is not possible to accurately predict the distribution of gas emission to various points of discharge. At this point in time it is only possible to provide an orders of magnitude analysis in this respect.

The following assumptions and calculation strategy has been employed

1. As mining progresses it will disturb the gas reservoir releasing gas in place (Mm^3/km or m^3/m^2) at a rate approximately proportional to longwall retreat i.e. gate road advance will be similar to maintain a positive longwall float.

2. Under all circumstances, gas will desorb to a residual gas content of $1.5m^3/t$. This value is based on average gas contents and isotherms (section 3.1.1 above). This value may over estimate total gas emission from production coal and coal remaining in the goaf if the actual residual gas content is higher.

3. Given the close proximity of roof coal and to err on the side of caution, it is assumed that all gas will be released during mining i.e. residual gas in coal pillars is ignored as is gas emission from sealed areas.

4. Pre drainage, by what ever method, will reduce the coal seam gas content to $5.0m^3/t$ i.e. below outburst thresholds. This assumption influences the distribution of gas emission to drainage or ventilation and should be reviewed once results of the surface MRD trials are available.

5. Of gas remaining in production coal, 15% will report to underground ventilation systems and 85% will report to surface stockpiles. The 15% value is based on average underground residence time and gas contents (section 3.1.3 above) which of course will change with the length of main conveyor systems and gas contents at time of mining. This value should be reviewed once further core sample become available from western blocks as this assumption influences the distribution of gas emission between VAM and surface stock piles.

6. Of remaining gas in place, 40% will be captured by goaf drainage with the balance reporting to ventilation systems during longwall production. Higher capture efficiency may be achieved subject to management of spontaneous combustion.

Based on these assumptions the estimated distribution of gas emission is shown in Figures 4.3 and 4.4 together with longwall specific gas emission rates in Figures 4.5 and 4.6. Based on a production rate of 5.0Mtpy without top coal caving, average longwall gas emission rates are shown in Figures 4.7 and 4.8.

The life of mine emission profile is shown in Table 4.1 and graphically in Figures 4.9 to 4.11.

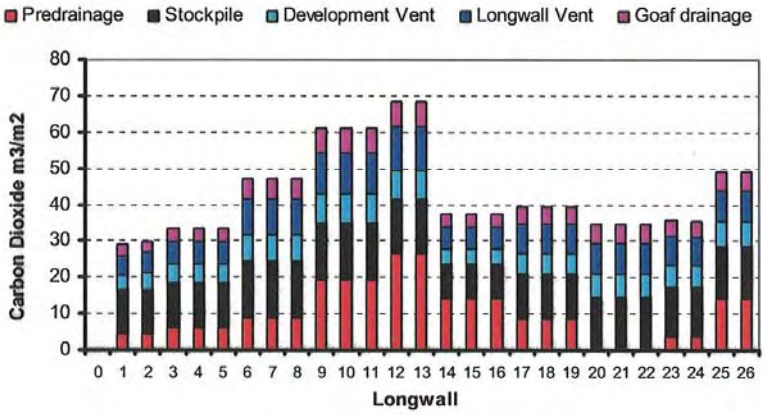


Figure 4.3 Distribution of Carbon Dioxide Emissions m^3/m^2

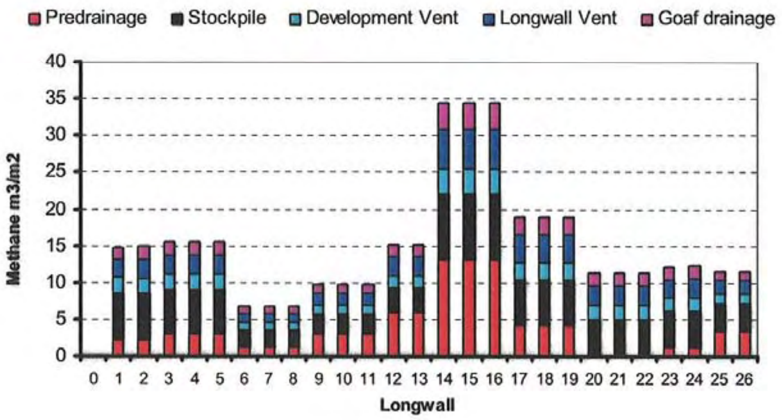
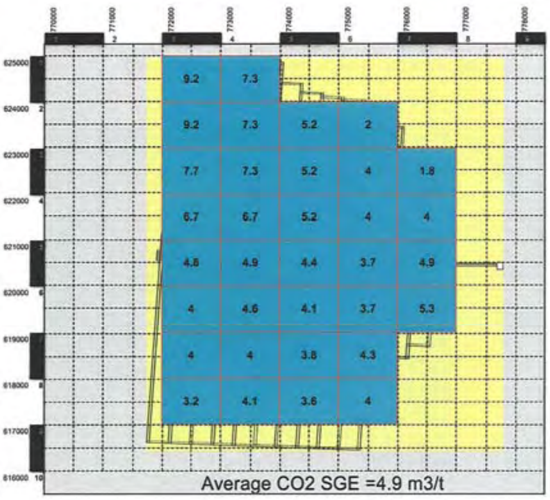


Figure 4.4 Distribution of Methane Emissions m^3/m^2



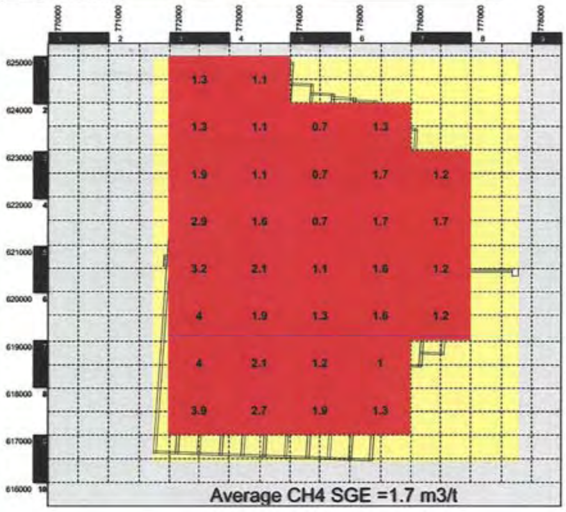
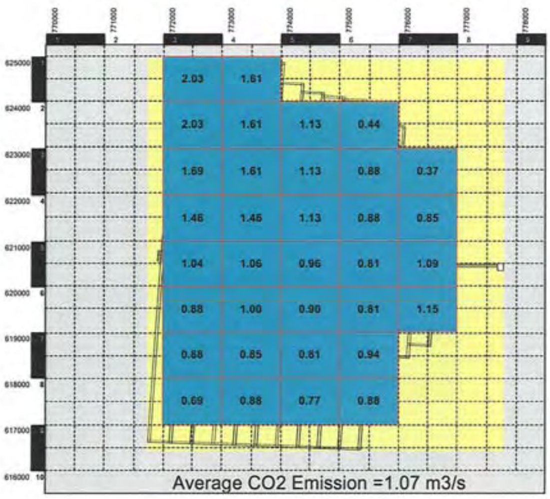


Figure 4.5 Specific Gas Emission – Carbon Dioxide

Figure 4.6 Specific Gas Emission – Methane



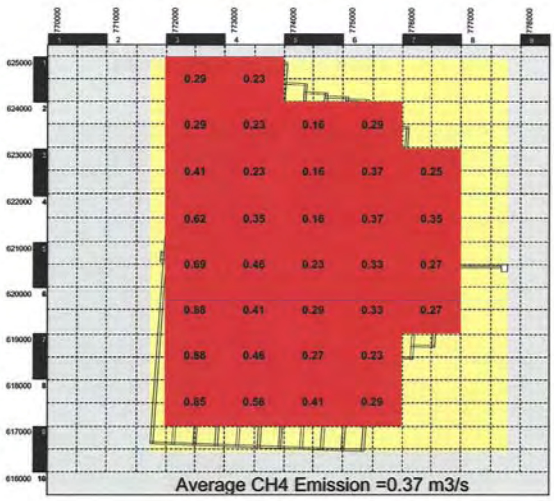


Figure 4.7 Longwall 5Mtpy Gas Emission – Carbon Dioxide

Figure 4.8 Longwall 5Mtpy Gas Emission – Methane

Table 4.1 LOM Emission Profile

LW	Start Yr	End Yr	Pre Drain CO2 Mm3	Pre Drain CH4 Mm3	Total Vent CO2 Mm3	Total Vent CH4 Mm3	Goaf Drainage CO2 Mm3	Goaf Drainage CH4 Mm3	Surface Stockpile CO2 Mm3	Surface Stockpile CH4 Mm3	Total CO2 Mm3	Total CH4 Mm3	Total CO2 t CO2 - e	Total CH4 t CO2 - e	Mine Total t CO2 - e	Mine Total AU$M
0																
1	0.0	0.5	2.8	1.4	9.8	4.6	2.2	1.0	7.5	4.0	22.2	11.0	41,300	157,020	198,320	4.96
2	0.6	1.3	3.5	1.8	13.1	5.6	2.6	1.4	9.6	5.1	28.8	13.9	53,559	198,136	251,695	6.29
3	1.4	2.2	5.6	2.6	15.9	6.5	3.3	1.7	11.1	5.5	35.9	16.4	66,808	233,433	300,241	7.51
4	2.3	3.2	6.5	3.0	17.5	7.2	3.8	1.9	12.8	6.4	40.6	18.6	75,536	264,584	340,120	8.50
5	3.3	4.2	6.5	3.0	20.0	6.0	3.8	1.9	12.8	6.4	43.1	17.4	80,148	247,440	327,588	8.19
6	4.3	5.3	9.5	1.4	26.5	3.4	6.0	0.9	17.3	2.6	59.2	8.2	110,115	117,496	227,611	5.69
7	5.4	6.3	9.8	1.4	27.6	3.5	6.2	1.0	17.8	2.7	61.4	8.5	114,125	121,718	235,843	5.90
8	6.4	7.4	10.4	1.5	31.4	4.1	6.6	1.0	18.9	2.8	67.2	9.5	125,034	135,206	260,240	6.51
9	7.6	8.7	27.0	4.3	38.7	5.5	9.3	1.6	21.8	3.8	96.7	15.2	179,829	216,067	395,896	9.90
10	8.9	10.0	27.0	4.3	38.7	5.5	9.3	1.6	21.8	3.8	96.7	15.2	179,829	216,067	395,896	9.90
11	10.2	11.3	27.0	4.3	38.7	6.1	9.3	1.6	21.8	3.8	96.7	15.8	179,886	224,791	404,677	10.12
12	11.5	12.6	37.2	8.3	39.6	7.8	9.8	2.3	20.7	4.9	107.2	23.3	199,429	332,548	531,977	13.30
13	12.8	13.9	37.2	8.3	34.4	10.4	9.8	2.3	20.7	4.9	102.0	25.9	189,689	369,952	559,641	13.99
14	14.1	15.2	19.9	18.4	20.5	17.1	4.8	5.0	13.2	12.4	58.4	52.9	108,573	754,009	862,582	21.56
15	15.4	16.6	19.9	18.4	20.5	17.1	4.8	5.0	13.2	12.4	58.4	52.9	108,573	754,009	862,582	21.56
16	16.7	17.9	19.9	18.4	22.5	15.7	4.8	5.0	13.2	12.4	60.3	51.5	112,231	734,086	846,318	21.16
17	18.0	19.2	12.0	5.9	27.4	12.0	6.5	3.5	17.0	8.5	62.9	29.9	117,082	426,096	543,178	13.58
18	19.3	20.5	12.0	5.9	27.4	12.0	6.5	3.5	17.0	8.5	62.9	29.9	117,082	426,096	543,178	13.58
19	20.6	21.8	12.0	5.9	28.3	11.2	6.5	3.5	17.0	8.5	63.8	29.1	118,754	414,739	533,494	13.34
20	21.9	23.1	1.3	0.5	29.9	9.0	6.9	2.5	19.0	6.6	57.1	18.6	106,167	264,848	371,016	9.28
21	23.2	24.4	1.3	0.5	29.9	9.0	6.9	2.5	19.0	6.6	57.1	18.6	106,167	264,848	371,016	9.28
22	24.5	25.7	1.3	0.5	29.6	8.9	6.9	2.5	19.0	6.6	56.8	18.5	105,693	264,293	369,986	9.25
23	25.8	27.0	5.2	1.8	23.0	7.1	6.3	2.4	18.9	6.7	53.3	18.0	99,214	256,302	355,516	8.89
24	27.1	27.5	2.1	0.7	11.3	3.2	2.5	1.0	7.5	2.7	23.4	7.6	43,443	108,731	152,175	3.80
25	27.7	28.1	7.4	1.8	11.1	2.3	2.6	0.6	7.7	1.9	28.7	6.7	53,386	95,340	148,726	3.72
26	28.2	28.6	6.4	1.6	7.0	1.5	2.2	0.6	6.7	1.7	22.2	5.2	41,360	74,745	116,106	2.90
			330	126	640	202	150	58	403	152	1,523	538	2,833,013	7,672,602	10,505,616	263

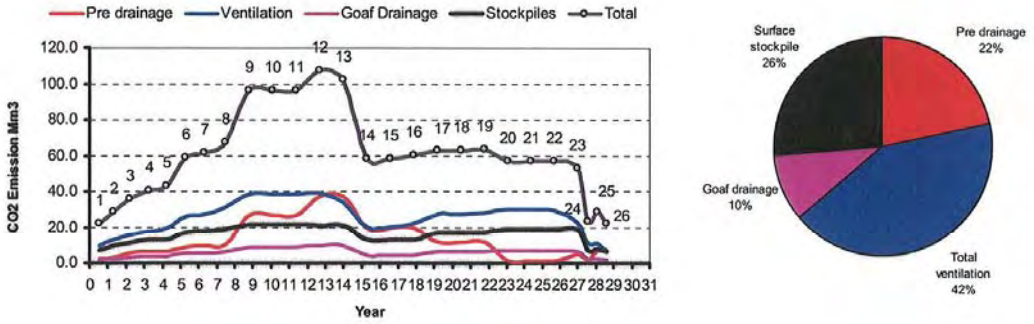


Figure 4.9 LOM Carbon Dioxide Emission Profile

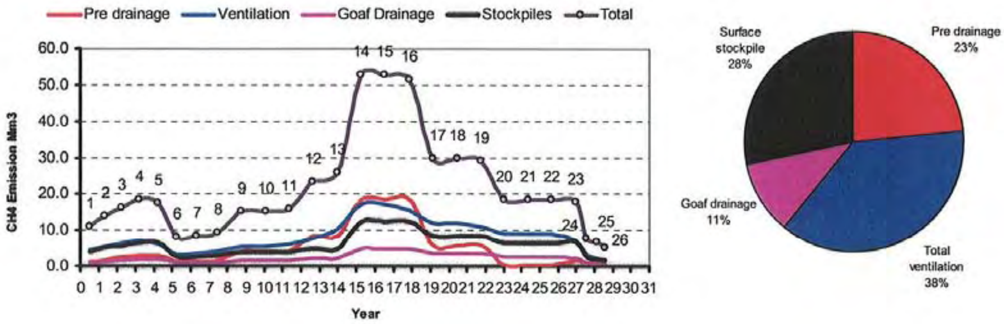


Figure 4.10 LOM Methane Emission Profile

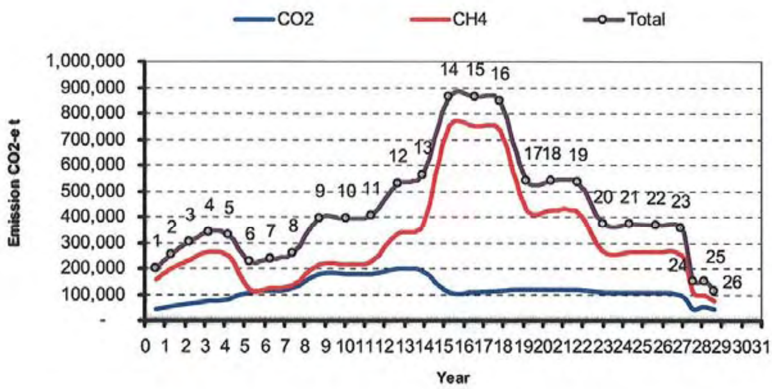


Figure 4.11 LOM CO_2-e Emission Profile

4.3 Mitigation of Methane Emission

The potential CO_2-e charge associated with pre and goaf drained methane will, if western block contours are representative, be significant.

Thermal or catalytic oxidation VAM units destroy methane in concentrations from about 0.3 to 0.9% CH_4. The units can manage about 17m^3/s of gas mixture and cost about AU$M 1.5 capital to purchase with ongoing power consumption of about 200kW (AU$87,000 per year). It is technically feasible to employ one or more of these units to destroy methane in captured gas streams using appropriate intake dilution and additional hater energy to overcome damping effects of carbon dioxide. For example, if 1.0m^3/s of gas is being captured with a composition of 10% CH_4 and 90% CO_2 then a 11: dilution ratio would produce a gas mixture that could be passed through a VAM unit.

An analysis of VAM unit requirements to destroy pre drained methane for average conditions in each longwall block is provided in Table 4.1 on the basis that seam gas contents will be reduced to 5m^3/t. For most of the mining area 1 or 2 units would be sufficient with up to 5 units in higher methane contents to the west.

The recommended approach is to plan to install a single unit to manage pre drained gas from initial longwalls. Quite obviously the number of units actually required in the future will depend on actual methane composition of seam gas and effectiveness of pre drainage. Both these factors have a high degree of uncertainty and therefore must be reviewed as additional data is obtained.

Table 4.2 Pre Drained Methane Destruction With VAM Units

LW	Average CH_4 %	Average CH_4 m3/s	Drained Gas m3/s	Mixture Volume 0.9% CH_4 m3/s	Mixture CH_4 %	Mixture CO_2 %	Number VAM Units	Value Gained AU$M	Net Cost AU$M
0									
1	35.0	0.08	0.24	9.39	0.90	1.67	1	0.51	4.45
2	35.0	0.08	0.23	9.09	0.90	1.67	1	0.63	5.67
3	33.3	0.11	0.33	12.04	0.90	1.80	1	0.94	6.57
4	33.3	0.11	0.33	12.04	0.90	1.80	1	1.08	7.42
5	33.3	0.11	0.33	12.04	0.90	1.80	1	1.08	7.11
6	13.0	0.05	0.36	5.20	0.90	6.02	1	0.48	5.21
7	13.0	0.05	0.36	5.20	0.90	6.02	1	0.50	5.40
8	13.0	0.05	0.36	5.20	0.90	6.02	1	0.53	5.98
9	14.8	0.12	0.78	12.82	0.90	5.20	1	1.54	8.36
10	14.8	0.12	0.78	12.82	0.90	5.20	1	1.54	8.36
11	14.8	0.12	0.78	12.82	0.90	5.20	1	1.54	8.58
12	19.0	0.22	1.17	24.63	0.90	3.84	2	2.95	10.35
13	19.0	0.22	1.17	24.63	0.90	3.84	2	2.95	11.04
14	48.8	0.49	1.01	54.64	0.90	0.95	4	6.55	15.01
15	48.8	0.49	1.01	54.64	0.90	0.95	4	6.55	15.01
16	48.8	0.49	1.01	54.64	0.90	0.95	4	6.55	14.60
17	33.8	0.16	0.47	17.57	0.90	1.77	2	2.11	11.47
18	33.8	0.16	0.47	17.57	0.90	1.77	2	2.11	11.47
19	33.8	0.16	0.47	17.57	0.90	1.77	2	2.11	11.23
20	26.3	0.01	0.05	1.34	0.90	2.53	1	0.16	9.11
21	26.3	0.01	0.05	1.34	0.90	2.53	1	0.16	9.11
22	26.3	0.01	0.05	1.34	0.90	2.53	1	0.16	9.09
23	26.3	0.05	0.18	5.29	0.90	2.53	1	0.63	8.25
24	26.7	0.05	0.18	5.38	0.90	2.48	1	0.26	3.55
25	20.0	0.13	0.64	14.29	0.90	3.60	1	0.64	3.08
26	20.0	0.13	0.64	14.29	0.90	3.60	1	0.56	2.35
								44.8	217.80

A similar analysis of methane emission reporting to ventilation indicates that resultant exhaust shaft concentrations will be below 0.3% and therefore not suitable for these units.

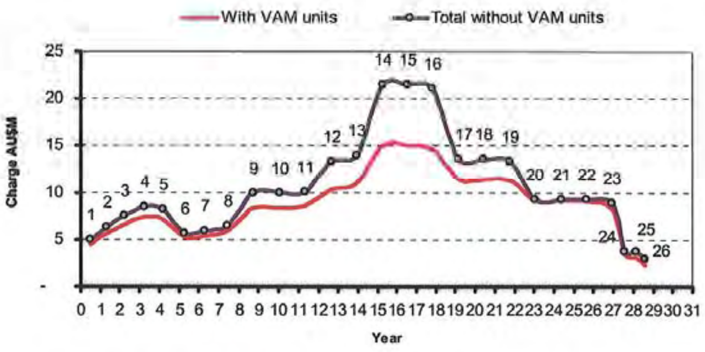


Figure 4.12 LOM CO_2-e Charge Profile With and Without Methane Destruction

5 REFERENCES

Blanche M, 2008. Preliminary Gas Management Strategy
GeoGAS Memo. 17th June 2008.

Gray I, 2008. Groundwater Testing For Narrabri Coal Boreholes NC-114, NC-110. NC-111, NC115.
SIGRA Report 14th November 2006

Williams G, 2008. Gas Content Testing Narrabri Coal Project.
GeoGAS Report No.: 2008-535 24th September 2008