APPENDIX K

Greenhouse Gas Assessment

Tahmoor South Project

Greenhouse Gas Assessment of the Amended Project

10 February 2020

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The business of sustainability

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10 February 2020

Tahmoor South Project

Greenhouse Gas Assessment of the Amended Project

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1. INTRODUCTION

ERM has been commissioned by SIMEC's Tahmoor Coal Pty Ltd (Tahmoor Coal) to complete a Greenhouse Gas (GHG) assessment for the amended Tahmoor South Project (the Project). The purpose of this assessment is to complete a GHG component of the project for a maximum run-of-mine (ROM) production of 4 million tonnes per annum (Mtpa). Tahmoor Coal and SIMEC Mining are part of the Liberty Steel Group within the Gupta Family Group (GFG) Alliance.

1.1 Background

Tahmoor Coal is seeking development consent for the continuation of mining at Tahmoor Mine, extending underground operations and associated infrastructure south, within the Bargo area. The proposed development seeks to extend the life of underground mining at Tahmoor Mine for an additional 13 years until approximately 2035.

In accordance with the requirements of the *Environmental Planning and Assessment Act 1979* (EP&A Act), the *Environmental Planning & Assessment Regulation 2000* (Regulation) and the Secretary's Environmental Assessment Requirements (SEARs) an Environmental Impact Statement (EIS) was prepared to assess the potential environmental, economic and social impacts of the Project. The EIS for the Project was placed on public exhibition by the Department of Planning, Industry and Environment (DPIE) (formerly the Department of Planning and Environment (DPE)) from 23 January 2019 to 5 March 2019.

Key issues raised in submissions included concerns relating to the proposed extent of longwall mining, the magnitude of subsidence impacts and the extent of vegetation clearing required for the expansion of the reject emplacement area (REA). In response to these and other issues raised in Government agency, local Council, stakeholder and community submissions, and as a result of ongoing mine planning, several amendments have been made to the proposed development, so as to also further reduce the potential environmental impacts of the Tahmoor South Project.

The key amendments to the Project since public exhibition of the EIS are:

- A revised mine plan, including:
  - an amended longwall panel layout and the removal of LW109;
  - a reduction in the height of extraction within the longwall panels from up to 2.85 metres (m) to up to 2.6 m; and
  - a reduction in the proposed longwall width, from up to 305 m to approximately 285 m.
- A reduction in the total amount of Run-of-Mine (ROM) coal to be extracted over the Project life, from approximately 48 million tonnes (Mt) to approximately 43 Mt of ROM coal, comprising;
  - 30 Mt of coking coal product (reduced from 35 Mt);
  - 2 Mt of thermal coal product (reduced from 3.5 Mt)
- A revised extended REA; including:
  - a reduction in the additional capacity required to accommodate the Project;
  - a reduction in the REA extension footprint, from 43 ha to 11 ha;
  - an increase in the final height of the REA (from RL 305 m to RL 310 m).
- Confirmation of the location and footprint of ancillary infrastructure associated with the ventilation shaft sites (e.g. the power connection easement for ventilation shaft site TSC1); and
- A continuation of the use of the existing upcast shaft (T2); although, operation will reduce from two fans during Tahmoor North operations to one fan once the new ventilation shafts and fans (TSC1 and TSC2) are in operation in Tahmoor South.

No amendments have been made to other key aspects of the Project as presented in the EIS for which approval is sought, such as the proposed annual coal extraction rate, mining method, traffic movements and employee numbers. A detailed description of the amended development is provided in the Amended Project Report (AECOM 2020).

1.1.1 Mine ventilation

The Tahmoor South Project will utilise the existing mine's ventilation system. In addition the Project will require the construction of two new ventilation shafts to provide reliable and adequate supply of ventilation air to personnel in the mine to ensure a safe working environment is maintained.

1.1.2 Gas drainage operations

Pre-gas drainage activities are currently carried out underground, via drilling and drainage from the roadways developed for longwall panels. Gas is drawn from the coal seam by vacuum and piped to the onsite gas plant at the surface facilities area via the underground pipe network. Underground gas drainage of the coal seam will continue ahead of longwall development for the life of mining.

Energy Developments Limited (EDL) operates a Waste Coal Mine Gas (WCMG) Power Plant at Tahmoor Mine, on land leased from Tahmoor Coal.

Gas management at Tahmoor Mine consists of the following infrastructure:

- Tahmoor Mine Gas Plant;
- Tahmoor Mine Gas Plant Vent;
- Tahmoor Mine Flare Plant; and
- WCMG Power Plant, if available.

Commercial agreements are in place between Tahmoor Coal and EDL for the WCMG Power Plant to operate until 2035. If the WCMG Power Plant is not operated, the gas will be diverted to the Tahmoor Mine Flare Plant, which has sufficient design capacity to accommodate this additional gas.

At the gas plant, the collected gas is tested to determine its composition and processed via one of the three possible options available at Tahmoor Mine:

- If the gas has sufficient methane, it will be used to generate electricity at the existing WCMG Power Plant, while the WCMG Power Plant remains operational at Tahmoor Mine.
- If the gas composition does not meet the specification for electricity generation or in circumstances where the WCMG Power Plant is not operational at Tahmoor Mine, it will be sent to the onsite gas flare plant where the methane will be flared.
- If the gas does not have sufficient methane for the operation of the flare plant, it will be vented into the atmosphere by the gas vent stack at the gas plant.

Tahmoor Coal will continue to utilise the existing power generation plant, and gas flare plant and upgrade and/or replace them with additional or replacement plants as required.

1.1.3 Post gas drainage

Post gas drainage will be required as strata relaxation caused by the retreating underground longwall face will liberate volumes of gas into the mine workings from the underlying Wongawilli seam and from overlying strata, which is released due to fracturing of the goaf. At the conclusion of mining from each panel, the panel will be sealed and gas drawn from the sealed areas as part of the post gas drainage operations. Additionally, boreholes are proposed to be drilled from the mine workings into the Wongawilli seam. These boreholes will be designed to collect the gas at its source or to intercept gas before it migrates into the mine workings.

The gas collected from the in-seam and cross-measure boreholes will be drawn by vacuum via the underground pipe network to the on-site gas plant located at the surface facilities area.

1.1.4 Mine ventilation return air

The ventilation system will deliver fresh air into the mine from the existing and proposed downcast vent shafts and will extract stale air from the mine via the proposed upcast vent shaft.

Some methane is contained within the mine ventilation return air, and this is vented to the atmosphere at the upcast shaft.

1.2 Amended project

The amended development would use longwall mining to extract coal from the Bulli seam within the bounds of Consolidated Coal Lease 716 (CCL716) and CCL747. Coal extraction of up to four (4) million tonnes of ROM coal per annum is proposed as part of the development with extraction of up to 43 Mt of ROM coal over the life of the Project. The project would produce approximately:

- 30 Mt coking coal product;
- 2 Mt thermal coal product; and
- 12 Mt of rejects.

These approximate market mix volumes include moisture and are therefore an estimate only. Once the coal has been extracted and brought to the surface, it would be processed at Tahmoor Mine’s existing CHPP and coal clearance facilities, and then transported via the existing rail loop, the Main Southern Railway and the Moss Vale to Unanderra Railway to Port Kembla and Newcastle (from time to time) for Australian and international markets. Up to 200,000 tonnes per annum of either product coal or reject material is proposed to be transported to customers via road.

The amended development would use the existing surface infrastructure at the Tahmoor Mine surface facilities area. Some upgrades are proposed to facilitate the extension.

The amended development also incorporates the planning for rehabilitation and mine closure once mining ceases.

In summary, the key components of the amended development comprise:

- Longwall mining in the Central Domain;
- Mine development including underground development, vent shaft construction, pre-gas drainage and service connection;
- Upgrades to the existing surface facilities area including:
  - Upgrades to the CHPP;
  - Expansion of the existing REA;
  - Additional mobile plant for coal handling;
  - Additions to the existing bathhouses and associated access ways; and
  - Upgrades to onsite and offsite service infrastructure, including electrical infrastructure;
- Rail transport of product coal to Port Kembla and Newcastle (from time to time);
- Up to 200,000 tonnes per annum of either product coal or reject material is proposed to be transported to customers via road;
- Mine closure and rehabilitation; and
- Environmental management.

2. RELEVANT LEGISLATION

2.1 International framework

2.1.1 Intergovernmental Panel on Climate Change

The Intergovernmental Panel on Climate Change (IPCC) is a panel established in 1988 by the World Meteorological Organisation (WMO) and the United Nations Environment Programme (UNEP) to provide independent scientific advice on climate change. The panel was originally asked to prepare a report, based on available scientific information, on all aspects relevant to climate change and its impacts and to then formulate realistic response strategies. This first assessment report of the IPCC served as the basis for negotiating the United Nations Framework Convention on Climate Change (UNFCCC).

The IPCC also produces a variety of guidance documents and recommended methodologies for GHG emissions inventories, including (for example):

- 2006 IPCC Guidelines for National GHG Inventories; and
- Good Practice Guidance and Uncertainty Management in National GHG Inventories (2000).

Since the UNFCCC entered into force in 1994, the IPCC remains the pivotal source for scientific and technical information relevant to GHG emissions and climate change science.

The IPCC operates under the following mandate: “to provide the decision-makers and others interested in climate change with an objective source of information about climate change”. The IPCC does not conduct any research nor does it monitor climate-related data or parameters. Its role is to assess on a comprehensive, objective, open and transparent basis the latest scientific, technical and socio-economic literature produced worldwide, relevant to the understanding of the risk of human-induced climate change, its observed and projected impacts and options for adaptation and mitigation. IPCC reports should be neutral with respect to policy, although they need to deal objectively with policy relevant scientific, technical and socio economic factors. They should be of high scientific and technical standards, and aim to reflect a range of views, expertise and wide geographical coverage” (IPCC, 2011).

The stated aims of the IPCC are to assess scientific information relevant to:

- Human-induced climate change;
- The impacts of human-induced climate change; and
- Options for adaptation and mitigation.

IPCC reports are widely cited within international literature, and are generally regarded as authoritative.

2.1.2 United Nations Framework Convention on Climate Change

The UNFCCC sets an overall framework for intergovernmental efforts to tackle the challenge posed by climate change. It recognises that the climate system is a shared resource, the stability of which can be affected by industrial and other emissions of CO_2 and other GHGs. The convention has near-universal membership, with 172 countries (parties) having ratified the treaty, the Kyoto Protocol.

Under the UNFCCC, governments:

- Gather and share information on GHG emissions, national policies and best practices.
- Launch national strategies for addressing GHG emissions and adapting to expected impacts, including the provision of financial and technological support to developing countries.
- Cooperate in preparing for adaptation to the impacts of climate change.

2.1.3 Kyoto Protocol

The Kyoto Protocol entered into force on 16 February 2005. The Kyoto Protocol built upon the UNFCCC by committing to individual, legally binding targets to limit or reduce GHG emissions. Annex I Parties (which includes Australia) are countries that were members of the Organisation for Economic Co-operation and Development (OECD) in 1992, plus countries with economies in transition such as Russia. The GHGs included in the Kyoto Protocol were:

- Carbon dioxide (CO_2);
- Methane (CH_4);
- Nitrous oxide (N_2O);
- Hydrofluorocarbons (HFCs);
- Perfluorocarbons (PFCs); and
- Sulfur hexafluoride (SF_6)

Each of the above gases has a different effect on the earth's warming and this is a function of radiative efficiency and lifetime in the atmosphere for each individual gas. To account for these variables, each gas is given a 'global warming potential' (GWP) that is normalised to CO_2. For example, CH_4 has a GWP of 28 over a 100 year lifetime (IPCC, 2014). This factor is multiplied by the total mass of gas to be released to provide a CO_2 equivalent mass, termed 'CO_2-equivalent'.The emission reduction targets were calculated based on a party's domestic GHG emission inventories (which included land use change and forestry clearing, transportation and stationary energy sectors). Domestic inventories required approval by the Kyoto Enforcement Branch. The Kyoto Protocol required developed countries to meet national targets for GHG emissions over a five year period between 2008 and 2012.

To achieve their targets, Annex I Parties had to implement domestic policies and measures. The Kyoto Protocol provided an indicative list of policies and measures that might help mitigate climate change and promote sustainable development.

Under the Kyoto Protocol, developed countries could use a number of flexible mechanisms to assist in meeting their targets. These market-based mechanisms include:

- Joint Implementation – where developed countries invest in GHG emission reduction projects in other developed countries.
- Clean Development Mechanism – where developed countries invest in GHG emission reduction projects in developing countries.

Annex I countries that failed to meet their emissions reduction targets during the 2008-2012 period were liable for a 30 per cent penalty (additional to the level of exceedance). A second commitment period was agreed in 2012 that spans from 2013 to 2020, whereby 37 countries, including Australia, were bound to emissions targets (DFAT, 2015).

2.1.4 Paris Agreement

In 2015, a historic global climate agreement was reached under the UNFCCC at the 21st Conference of the Parties (COP21) in Paris (known as the Paris Agreement). The Paris Agreement sets in place a durable and dynamic framework for all countries to take action on climate change from 2020 (that is, after the Kyoto period), building on existing efforts in the period up to 2020. Key outcomes of the Paris Agreement include:

- A global goal to hold average temperature increase to well below 2°C and pursue efforts to keep warming below 1.5°C above pre-industrial levels.
- All countries to set mitigation targets from 2020 and review targets every five years to build ambition over time, informed by a global stocktake.

- Robust transparency and accountability rules to provide confidence in countries' actions and track progress towards targets.
- Promoting action to adapt and build resilience to climate change.
- Financial, technological and capacity building support to help developing countries implement the Paris Agreement.

Australia ratified the Paris Agreement in November 2016. Australia's target under the Paris Agreement is to reduce emissions by 26-28 per cent below 2005 levels by the year 2030, progressing the levels of reduction required to meet the Kyoto Protocol targets.

2.2 Australian context

According to the Department of Environment and Energy (DoEE), Australia's GHG emissions have increased by 27.9% since 1990 reaching 534.7 Million tonnes of CO_2-equivalent ($MtCO_2$-e) in 2016 (excluding Land Use, Land Use Change and Forestry - LULUCF) (DoEE, 2016a). Stationary energy excluding electricity includes emissions from direct combustion of fuels, predominantly in the manufacturing, mining, residential and commercial sectors. In 2016, stationary energy excluding electricity accounted for 18% of Australia's national inventory (DoEE, 2016).

2.2.1 State Environment Planning Policy (Mining, Petroleum and Extractive Industries) 2007

Clause 14(2) of State Environmental Planning Policy (Mining, Petroleum and Extractive Industries) 2007 – The Mining SEPP, provides:

"(2) in determining a development application for development for the purposes of mining, petroleum production or extractive industry, the consent authority must consider an assessment of the greenhouse gas emissions (including downstream emissions) of the development, and must do so having regard to any applicable State or national policies, programs or guidelines concerning greenhouse gas emissions".

In this context, although the GHG protocol does not require indirect emissions or downstream emissions (Scope 3) emissions to be reported, they are included in this assessment.

2.2.2 National greenhouse and energy reporting framework

The National Greenhouse and Energy Reporting Act 2007 (Cth) (the NGER Act) establishes a mandatory obligation on corporations which exceed defined thresholds to report GHG emissions, energy consumption, energy production and other related information.

Corporate and facility reporting thresholds for GHG emissions and energy consumption or energy production are provided in Table 2.1.

Table 2.1 NGER reporting thresholds per financial year

Parameter	Reporting Threshold	
	Corporate	Facility
GHG Emissions (Scope 1&2) (kt CO_2-e)	50	25
Energy production (TJ)	200	100
Energy consumption (TJ)	200	100

Source: CER, 2017

If a corporation has operational control over facilities whose GHG emissions or energy use in a given reporting year:

- Individually exceed the relevant facilities threshold; or
- When combined with other facilities under the corporation's operational control, exceed the relevant corporate thresholds.

That corporation must report the relevant GHG emissions or energy use (as the case may be) for that year under the NGER Act. For example, this may include construction or other contractors.

It is anticipated that during construction, there will be multiple parties with operational control over different aspects of the site development. For this reason, while it is anticipated that there is likely to be some reporting requirement under the NGER scheme, this is likely to be apportioned across the NGER reporting corresponding to several corporations.

Once operational, the Project's total Scope 1 and 2 GHG emissions are anticipated to exceed 25,000 tonnes CO_2-e in a financial year. Because of this, the reporting of emissions is expected to be required under the NGER scheme.

Tahmoor Coal already reports under the NGER scheme. During the 2017-18 financial year Tahmoor Coal (under Simec (Australia) Mining Pty Ltd) reported a total Scope 1 emissions to be 1,396 ktCO_2-e and the Scope 2 emissions to be 82 ktCO_2-e, with total emissions equating to 1,487 ktCO_2-e (Clean Energy Regulator, 2019).

2.2.3 NSW Climate Change Policy Framework

The NSW Office of Environment and Heritage (OEH) published the NSW Climate Change Policy Framework in 2016, which aims to "maximise the economic, social and environmental wellbeing of NSW in the context of changing climate and current and emerging international and national policy settings and actions to address climate change". The long-term objectives of the Framework are to achieve net-zero emissions by 2050 and ensure NSW is more resilient and responsive to climate change. The key policy directions under the Framework are:

- Create an investment environment which manages the transition to reduced emissions
- Boost energy productivity and put downward pressure on energy bills
- Capture co-benefits and manage unintended impacts of external policies
- Take advantage of opportunities to grow new industries
- Reduce risks and damage to public and private assets arising from climate change
- Reduce climate change impacts on health and wellbeing
- Manage impacts on natural resources, ecosystems and communities

The Framework is being delivered through:

- A climate change fund strategic plan
- Developing value for emissions savings
- Embedding climate change considerations in government decision making
- Developing action plans and strategies and undertake additional policy investigation for sectors with risks, such as mining

Tahmoor Coal is an existing operation and is unlikely to affect the objectives of the NSW Climate Change Policy Framework.

3. METHODOLOGY

Quantification of GHG emissions has been completed in accordance with the GHG Protocol (WRI & WBCSD, 2004), IPCC and Australian Government GHG accounting/classification systems.

This GHGA is also guided by the emission estimation methodologies endorsed under the National Greenhouse and Energy Reporting Regulations 2008 (the NGER Regulations) (as amended in 2019). These describe the detailed requirements for reporting under the NGER framework and also provide a basis for estimating emissions from proposed activities.

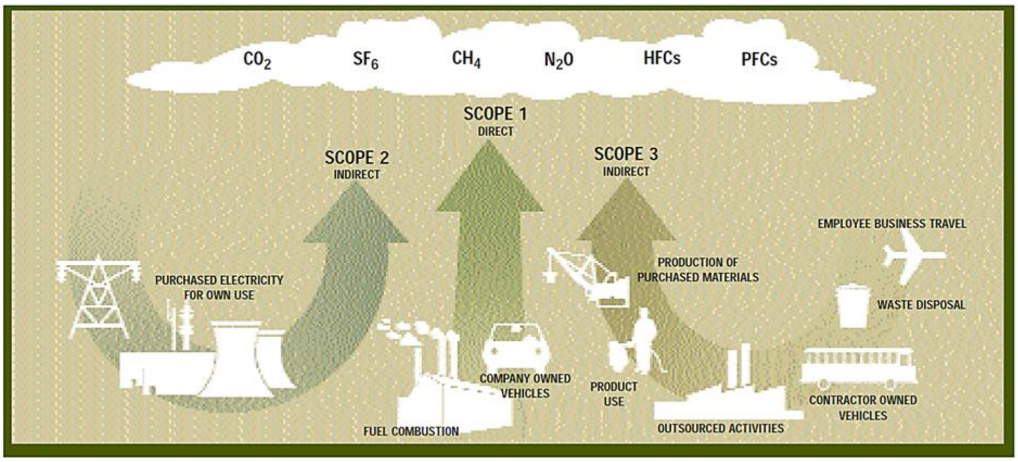
The Technical Guidelines for the Estimation of Greenhouse Gas Emissions by Facilities in Australia (the NGER Guidelines) (DoEE, 2017) support reporting under the NGER Act. They have been designed to assist corporations in understanding and applying the NGER Measurement Determination.

The NGER Guidelines are reporting year specific, and outline calculation methods and criteria for determining GHG emissions, energy production, energy consumption and potential GHG emissions embodied in combusted fuels. The latest published NGER Guidelines (at the time of writing) have been referenced.

3.1 The GHG Protocol

The GHG Protocol establishes an international standard for accounting and reporting of GHG emissions. The GHG Protocol has been adopted by the International Organization for Standardisation, endorsed by GHG initiatives (such as the Carbon Disclosure Project) and is compatible with existing GHG trading schemes.

Under this protocol, three “scopes” of emissions (Scope 1, Scope 2 and Scope 3) are defined for GHG accounting and reporting purposes. This terminology has been adopted in Australian GHG reporting and measurement methods and has been employed in this assessment. The definitions for Scope 1, Scope 2 and Scope 3 emissions are provided in the following sections, with a visual representation provided in Figure 3.1.



Source: WRI & WBCSD 2004

Figure 3.1 Overview of scopes and emissions across a reporting entity

3.1.1.1 Scope 1: Direct greenhouse gas emissions

Direct GHG emissions are defined as those emissions that occur from sources that are owned or controlled by the reporting entity. Direct GHG gas emissions are those emissions that are principally the result of the following types of activities undertaken by an entity:

- Generation of electricity, heat or steam. These emissions result from combustion of fuels in stationary sources;
- Physical or chemical processing. Most of these emissions result from manufacture or processing of chemicals and materials, e.g., the manufacture of cement, aluminium, etc;
- Transportation of materials, products, waste and employees. These emissions result from the combustion of fuels in entity owned/controlled mobile combustion sources, e.g., trucks, trains, ships, aeroplanes, buses and cars; and
- Fugitive emissions. These emissions result from intentional or unintentional releases, e.g., equipment leaks from joints, seals, packing, and gaskets; methane emissions from coal mines and venting; HFC emissions during the use of refrigeration and air conditioning equipment; and methane leakages from gas transport.

3.1.1.2 Scope 2: Energy product use indirect greenhouse gas emissions

Scope 2 emissions are a category of indirect emissions that accounts for GHG emissions from the generation of purchased energy products (principally, electricity, steam/heat and reduction materials used for smelting) by the entity.

Scope 2 covers purchased electricity defined as electricity that is purchased or otherwise brought into the organisational boundary of the entity. Scope 2 emissions physically occur at the facility where electricity is generated. Entities report the emissions from the generation of purchased electricity that is consumed in its owned or controlled equipment or operations as Scope 2.

3.1.1.3 Scope 3: Other indirect greenhouse gas emissions

Scope 3 emissions are defined as those emissions that are a consequence of the activities of an entity, but which arise from sources not owned or controlled by that entity. Some examples of Scope 3 activities provided in the GHG Protocol are extraction and production of purchased materials, transportation of purchased fuels, and use of sold products and services.

The GHG Protocol provides that reporting Scope 3 emissions is optional. If an organisation believes that Scope 3 emissions are a significant component of the total emissions inventory, these can be reported along with Scope 1 and Scope 2. However, the GHG Protocol notes that reporting Scope 3 emissions can result in double counting of emissions and can also make comparisons between organisations and/or products difficult because reporting is voluntary. Double counting needs to be avoided when compiling national (country) inventories under the Kyoto Protocol. The GHG Protocol also recognises that compliance regimes are more likely to focus on the “point of release” of emissions (i.e. direct emissions) and/or indirect emissions from the purchase of electricity. Notwithstanding that Scope 3 reporting is optional, they have been estimated and are reported in Section 4.8. As noted in Section 2.2.1, Scope 3 emissions are also required to be taken into consideration by consent authorities so should be calculated as part of the assessment process for the development application.

Under the NGER Act, facilities triggering GHG emission and energy usage thresholds are required to report Scope 1 and Scope 2, but not Scope 3.

Scope 1 emissions from the Project comprise:

- Run-of-mine coal extracted from a gassy underground mine;
- Collection and venting/flaring of pre-drained gas

- Collection and venting/flaring of goaf gas (post drainage);
- Venting of mine ventilation return air;
- Diesel oil combustion;
- Petrol combustion;
- Post-mining activities; and
- Use of sulfur hexafluoride (SF_6)

Scope 2 emissions from the Project are limited to electricity consumption.

3.2 National Greenhouse and Energy Reporting (Measurement) Determination 2008

The National Greenhouse and Energy Reporting (Measurement) Determination 2008 (the NGER Determination) commenced on 1 July 2008 and is made under subsection 10 (3) of the NGER Act. It provides a framework for the measurement of the following arising from the operation of facilities:

- Greenhouse gas emissions;
- The production of energy; and
- The consumption of energy.

The determination addresses Scope 1 and Scope 2 emissions. The methods are presented in a tiered structure with higher tiers producing less uncertain results but requiring more data to employ. In the NGER Determination there are 4 categories of Scope 1 emissions (the code for the IPCC classification is provided in brackets):

- Fuel combustion (UNFCCC Category 1.A);
- Fugitive emissions from fuels, which deals with emissions released from the extraction, production, flaring of fuel, processing and distribution of fossil fuels (UNFCCC Category 1.B);
- Industrial processes emissions (UNFCCC Category 2); and
- Waste emissions (UNFCCC Category 6).

It is acknowledged that as the NGER Guidelines are derived from the NGER Determination, where there is a perceived contradiction between the NGER Guidelines and NGER Determination, the NGER Determination has taken precedence.

3.3 Assessment approach

GHG emissions have been estimated for the Project based upon the methods outlined in the following documents:

- The National Greenhouse and Energy Reporting (Measurement) Amendment Determination 2008 (as amended 2019);
- Site specific information;
- The NGER Guidelines; and
- The NGA Factors.

3.4 Limitations

As discussed previously, Scope 3 emissions are indirect emissions downstream of the Project. That is, they are associated with the Project but occur as direct (scope 1) emissions at other locations and controlled by other entities. Scope 3 emissions recognise that the coal produced at Tahmoor will continue to generate GHG emissions as it moves from being the output from that operation to the input for the next entity in the value chain. When these scope 1 emissions are calculated by that next entity, they will by definition be counted twice. Classifying the different emission scopes was deliberate, to avoid double counting.

The importance of avoiding double counting is recognised under international and Australia GHG reporting frameworks. The Paris Agreement requires parties to avoid double counting consistent with the guidance adopted by the UN Framework Convention on Climate Change (UNFCCC).

Excluding Scope 3 emissions from the reporting requirements under Australian law would effectively avoid double counting. However, as noted in the Mining SEPP, as they are required to be considered by consent authorities they are assessed here.

4. GREENHOUSE GAS CALCULATIONS

4.1 Introduction

The following sections present the GHG calculations and resultant estimated emissions from each of the GHG scopes as described in Section 3.1. All GHG calculations have been made using the relevant equations and emissions factors given within the NGER Measurement Determination. Data provided by Tahmoor Coal has been used as input into these equations.

Consumption data (diesel use, electricity consumption etc.) for the Project has been provided by Tahmoor Coal for fiscal years 2009/2010, 2010/2011, 2011/2012 and 2012 to March 2013 in the form of NGER Scheme declarations.

ROM and product coal values for these years along with the projections for the Project years (2019 to 2035) have also been provided. As projections of future years' consumption data has not been provided, intensity factors of consumption per tonne of ROM coal have been calculated to estimate future consumption levels. A total of all year's consumption was taken and divided by the total ROM coal over the same period. These intensity factors are as listed in Table 4.1 below:

Table 4.1 Intensity factors for consumables used for future project year scenarios

Year	ROM Coal Mined (kt)	Diesel (kL)	Petrol (kL)	Oils (kL)	Lubricants (kL)	Electricity (MWh)	SF_6 (CO_2-et/t)
2009/2010	1,552	684	16	0	226	70,890	174
2010/2011	1,647	781	17	0	171	53,091	174
2011/2012	2,731	1,171	15	0.8	198	95,265	411
2012/2013	1,601	688	11	0	118	58,956	174
TOTAL	7,531	3,324	58	1	713	278,202	933
Intensity Factor (Usage/kt ROM)		0.44	0.008	0.0001	0.095	36.9	0.12

4.2 Fugitive emissions – Scope 1 emissions

Estimates of Scope 1 emissions from fugitive methane are based on information provided by Tahmoor Coal, and have been scaled in proportion to the ROM production values for each year. Fugitive methane emissions will be generated from various sources at the Project site including the following:

- Mine ventilation air;
- Pre-drainage;
- Post-drainage;
- Flaring; and
- Third party power generation (eg, the existing WCMG Power Plant).

Emissions for Scope 1 fugitive emissions were calculated using the following method:

Method 4 – extraction of coal (Division 3.6 of the NGER Technical Guidelines).

$$E_j = CO_{2-e_{j\,gen\,total}} - \gamma_j \left(Q_{ij,cap} + Q_{ij,flared} + Q_{ijtr}\right)$$

E_j	=	Fugitive emissions of gas type from extraction of coal	(t CO_2-e)
$CO_{2\text{-}e\ j\ gen,total}$	=	Mass of gas type before capture and flaring estimated using direct measurement.	(t CO_2-e)
Y_j	=	Factor to convert gas from m^3 at STP to t CO_2-e For methane – $6.784 \times 10^{-4} \times 25$ For carbon dioxide – 1.861×10^{-3}	
$Q_{ij,cap}$	=	Quantity of gas captured for combustion	m^3
$Q_{ij,flared}$	=	Quantity of gas flared	m^3
Q_{ijtr}	=	Quantity of gas transferred	m^3

[1] GJ = giga joules

[2] kg CO_2-e/GJ = kilograms of carbon dioxide equivalents per gigajoule

The estimated GHG emissions from individual Scope 1 sources by year are presented in Table 4.2 for the scenario where a power generation plant (eg, the existing WCMG Power Plant) is operating at Tahmoor.

Table 4.2 Estimated scope 1 emissions for the Project with power plant operating

Year	ROM (tpa)	Scope 1 Emissions from Mine Ventilation Air (t CO_2-e)	Scope 1 Emissions from Pre and Post-Drainage (t CO_2-e)	Scope 1 Emissions from Flares (t CO_2-e)	Scope 1 Emissions from Third Party Power Generation (t CO_2-e)	Total Scope 1 Emissions (t CO_2-e)
2020	270,166	74,862	99,624	30,321	13,817	218,624
2021	409,194	41,981	34,190	9,135	9,322	94,628
2022	2,025,727	76,191	73,930	22,253	16,074	188,448
2023	3,270,131	381,854	135,965	58,649	24,354	600,823
2024	3,118,603	371,533	123,244	49,200	18,527	562,504
2025	3,284,437	441,507	168,212	62,193	15,295	687,207
2026	3,353,014	350,198	238,106	77,935	7,091	673,330
2027	3,409,538	553,043	186,650	65,440	8,629	813,763
2028	3,342,829	485,040	760,581	0	3,968	1,249,589
2029	3,255,743	343,733	1,003,843	0	4,168	1,351,744
2030	3,409,127	483,914	806,046	0	3,437	1,293,397
2031	3,417,885	471,635	569,354	0	3,504	1,044,492
2032	3,139,055	334,310	714,290	0	3,571	1,052,171
2033	3,155,392	123,893	186,934	64,157	7,709	382,693
2034	2,566,647	277,942	140,102	46,937	18,178	483,159
2035	925,491	387,592	148,324	57,911	16,007	609,833
Total	**42,352,980**	5,199,228	5,389,395	544,131	173,651	11,306,405

The estimated GHG emissions from individual Scope 1 sources by year are presented in Table 4.3 for the scenario where a power generation plant (eg, the existing WCMG Power Plant) is not operating at Tahmoor Mine and this gas is unabated and released directly to the atmosphere.

Table 4.3 Estimated scope 1 emissions for the Project without power plant operating

Year	ROM (tpa)	Scope 1 Emissions from Mine Ventilation Air (t CO_2-e)	Scope 1 Emissions from Pre and Post-Drainage (t CO_2-e)	Total Scope 1 Emissions (t CO_2-e)
2020	270,166	74,862	436,679	593,612
2021	409,194	41,981	175,138	569,496
2022	2,025,727	76,191	366,610	601,121
2023	3,270,131	381,854	769,811	1,251,565
2024	3,118,603	371,533	640,433	1,126,051
2025	3,284,437	441,507	759,939	1,294,196
2026	3,353,014	350,198	887,396	1,330,162
2027	3,409,538	553,043	752,271	1,494,948
2028	3,342,829	485,040	477,923	1,054,966
2029	3,255,743	343,733	621,743	1,002,137
2030	3,409,127	483,914	510,168	1,103,727
2031	3,417,885	471,635	373,723	868,417
2032	3,139,055	334,310	453,280	883,489
2033	3,155,392	123,893	735,728	1,076,834
2034	2,566,647	277,942	637,341	927,409
2035	925,491	387,592	712,789	1,328,018
Total	**42,352,980**	**5,199,227**	**9,310,973**	**16,506,149**

The above emissions projection assumes that pre-drainage Scope 1 emissions will not occur prior to 2024, and will then continue for the remainder of the project life.

4.3 Fuel consumption – Scope 1 emissions

4.3.1 Diesel

Consumption of diesel oil has been provided by the client through previous years' NGER declaration forms. The total diesel accounted for within the data is equal to diesel used for transport, stationary and non-combustion purposes. It is noted that the Project does not use diesel for transport purposes (i.e. coal transport is the responsibility of a third party). Diesel consumed on-site is used in the following activities:

- Exploration and drilling;
- Extraction of coal (underground); and
- Coal handling.

It is noted that diesel has been used by on-site contractors in previous years for both transport and stationary purposes. The NGER Scheme reporting trigger however has never been met and current contractor diesel consumption is understood to be well below the threshold of 100 TJ of consumed energy. Therefore, it has been assumed that contractor diesel is not a significant source for future years, and is not quantified in this assessment.

Emissions for Scope 1 diesel consumption are calculated using the following method:

Method 1 – emissions of carbon dioxide, methane and nitrous oxide from liquid fuels other than petroleum based oils or greases (Subdivision 2.41 of the NGER Determination 2008 (as amended in 2019)).

GHG emissions from diesel consumption were estimated using the following equation:

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

Where:

E_{ij}	=	Emissions of GHG from diesel combustion	(t CO_2-e)
Q_i	=	Quantity of fuel	(GJ)[1]
EC_i	=	Energy content of fuel	(GJ/kL)
EF_{ijoxec}	=	Emission factor (Scope 1) for diesel combustion	(kg CO_2-e/GJ)[2]

[1] GJ = giga joules

[2] kg CO_2-e/GJ = kilograms of carbon dioxide equivalents per gigajoule

As described in Section 4.1 above, the quantity of diesel for Project years was estimated using an intensity factor of 0.44 kL of diesel/kt ROM coal.

Scope 1 fuel consumption emissions have been calculated using the energy content and emission factors from Part 3 of the NGER Measurement Determination and are presented in Table 4.4 and Table 4.5.

Table 4.4 Diesel (for stationary purposes) GHG emission factors – Scope 1

Fuel type	Energy Content (GJ/kL)	Emission factor (kg CO_2-e/GJ)		
		CO_2	CH_4	N_20
Diesel oil	38.6	69.9	0.1	0.2

Source: Schedule 1, Part 3 of the NGER Determination (2008)(as amended 2019).

The estimated annual and total GHG emissions from diesel usage are presented in Table 4.5.

Table 4.5 Projected diesel fuel consumption and GHG emissions

Year	ROM (tpa)	Estimated Diesel Usage (kL/y)	Scope 1 Emissions (t CO_2-e)
2020	270,166	119	323
2021	409,194	181	489
2022	2,025,727	894	2,423
2023	3,270,131	1,443	3,911
2024	3,118,603	1,376	3,730
2025	3,284,437	1,450	3,928
2026	3,353,014	1,480	4,010
2027	3,409,538	1,505	4,078
2028	3,342,829	1,475	3,998
2029	3,255,743	1,437	3,894
2030	3,409,127	1,505	4,077
2031	3,417,885	1,509	4,088
2032	3,139,055	1,386	3,754
2033	3,155,392	1,393	3,774
2034	2,566,647	1,133	3,070
2035	925,491	408	1,107
Total	**42,352,980**	**18,694**	**50,655**

4.3.2 *Unleaded petrol*

Consumption of Unleaded Petrol (ULP) has been provided by Tahmoor Coal through previous years' NGER declarations forms. ULP is currently used for mining support services at the project site.

Emissions for Scope 1 ULP consumption are calculated using the same method and equation as for diesel in Section 4.3.1.

The quantity of ULP for Project years was estimated using an intensity factor of 0.008 kL of ULP/kt ROM coal.

Scope 1 ULP emissions have been calculated using the energy content and emission factors from Part 3 of the NGER Measurement Determination and are presented in Table 4.6.

Table 4.6 ULP (Gasoline) for transport energy purposes for post-2004 vehicles GHG emission factors – Scope 1

Fuel type	Energy Content (GJ/kL)	Emission factor (kg CO_2-e/GJ)		
		CO_2	CH_4	N_20
Gasoline (other than for use as fuel in an aircraft)	34.2	67.4	0.02	0.2

Source: Schedule 1, Part 4 of the NGER Determination (2008) (as amended 2019).

The estimated annual and total GHG emissions from diesel usage are presented in Table 4.7.

Table 4.7 Projected ULP consumption and GHG emissions

Year	ROM (tpa)	ULP Usage (kL/y)	Scope 1 Emissions (t CO_2-e)
2020	270,166	2	5
2021	409,194	3	7
2022	2,025,727	16	36
2023	3,270,131	25	59
2024	3,118,603	24	56
2025	3,284,437	26	59
2026	3,353,014	26	60
2027	3,409,538	26	61
2028	3,342,829	26	60
2029	3,255,743	25	58
2030	3,409,127	26	61
2031	3,417,885	27	61
2032	3,139,055	24	56
2033	3,155,392	25	57
2034	2,566,647	20	46
2035	925,491	7	17
Total	**42,352,980**	**329**	**761**

4.4 Oils and lubricants consumption

Consumption of oils and lubricants (other than petroleum based oil as fuel) is required to be reported within the NGER framework. However, typically oils and lubricants data is used only in terms of characterising the associated energy consumption, as opposed to GHG emission. This is since typically such oils and lubricants are consumed below their temperature of combustion, whereby while energy is consumed, there is no associated emission, and these are deemed ‘consumed but not combusted’.

In view of the above discussion, oils and lubricants (other than petroleum based oil as fuel) are not considered further in within the scope of this greenhouse gas assessment.

4.5 Emissions of sulphur hexafluoride gas (SF_6) – Scope 1 emissions

Emissions of SF_6 may be released from the Project site through the use of this gas in insulated switch gear and circuit breaker applications. SF_6 stock has been provided by Tahmoor Coal via previous year’s NGER declaration forms.

Emissions of Scope 1 SF_6 are calculated using the following method:

Method 1 – emissions of hydrofluocarbons and sulphur hexafluoride gases (Section 4.102 of the NGER Determination 2008 (as amended 2019).

Greenhouse gas emissions from SF_6 is typically estimated using the following equation:

$$E_{jk} = Stock_{jk} \times L_{jk}$$

Where:

E_{jk}	=	Emissions of gas type summed over each equipment type	(t CO_2-e)
$Stock_{jk}$	=	Stock of gas type contained in equipment type	(t CO_2-e)
L_{jk}	=	Default leakage rates for a year of gas type	

The default leakage gas rate as given in the NGER Determination for SF_6 is 0.0089.

As described in Section 4.1, the GHG associated with SF_6 leakage for Project years was estimated using an intensity factor of 0.12 t CO2-e /kt ROM coal.

The estimated annual and total GHG emissions from SF6 are presented in Table 4.8.

Table 4.8 Projected SF_6 stocks and GHG emissions

Year	ROM (tpa)	SF6 Stock (t CO_2-e)	Scope 1 Emissions from SF_6 (t CO_2-e)
2020	270,166	33	0.3
2021	409,194	51	0.5
2022	2,025,727	251	2.2
2023	3,270,131	405	3.6
2024	3,118,603	386	3.4
2025	3,284,437	407	3.6
2026	3,353,014	415	3.7
2027	3,409,538	422	3.8
2028	3,342,829	414	3.7
2029	3,255,743	403	3.6
2030	3,409,127	422	3.8
2031	3,417,885	423	3.8
2032	3,139,055	389	3.5
2033	3,155,392	391	3.5
2034	2,566,647	318	2.8
2035	925,491	115	1.0
Total	**42,352,980**	**5,247**	**47**

4.6 Post-mining activities – Scope 1 emissions

Emissions for Scope 1 post-mining activities are calculated using the following method:

*Method 1 – post-mining activities related to gassy mines (Subdivision 2.41 of the NGER Determination (2008) (as amended in 2019)).*This method states the emission factors to be 0.017 t CO_2-e / t ROM coal extracted at the mine.

The estimated annual and total GHG emissions from post-mining activities are presented in Table 4.9.

Table 4.9 Estimated GHG emissions from post-mining activities – Scope 1

Year	ROM (tpa)	Scope 1 Emissions from post-mining activities (t CO_2-e)
2020	270,166	4,593
2021	409,194	6,956
2022	2,025,727	34,437
2023	3,270,131	55,592
2024	3,118,603	53,016
2025	3,284,437	55,835
2026	3,353,014	57,001
2027	3,409,538	57,962
2028	3,342,829	56,828
2029	3,255,743	55,348
2030	3,409,127	57,955
2031	3,417,885	58,104
2032	3,139,055	53,364
2033	3,155,392	53,642
2034	2,566,647	43,633
2035	925,491	15,733
Total	**42,352,980**	**720,001**

4.7 Electricity consumption – Scope 2 emissions

Consumption of electricity has been provided by Tahmoor Coal via previous years' NGER declaration forms. Electricity consumed on-site is used in the following activities:

- Extraction of coal (underground); and
- Mining support services (including administration);

Emissions for Scope 2 electricity consumption are calculated using the following method:

Method 1 – Indirect (scope 2) emission factors from consumption of purchased electricity from a grid (Subdivision 7.2 of the NGER Technical Guidelines 2008 (as amended in 2017).

GHG emissions from electricity consumption were estimated using the following equation:

$$Y = Q \times \frac{EF}{1000}$$

Where:

Y	=	Scope 2 Electricity emissions	(CO_2-e tonnes)
Q	=	Quantity of electricity purchased from the electricity grid during the year	(kWh/annum)[1]
EF	=	Scope 2 emission factor for the State of Territory in which the consumption occurs	(kg CO_2-e/kWh)[2]

[1] kWh/annum = kilowatt hours per annum

[2] kgCO_2-e/kWh = kilograms of carbon dioxide equivalents per kilowatt hour

As described in Section 4.1, the quantity of electricity for Project years was estimated using an intensity factor of 0.0369 MWh of electricity/t ROM coal.

Scope 2 emissions have been calculated using an emission factor of 0.83 kg CO_2-e/kWh for New South Wales and Australian Capital Territory as sourced from Part 7.2 of the NGER Technical Guidelines 2008 (as amended 2017).

The estimated annual and total GHG emissions from electricity usage are presented in Table 4.10.

Table 4.10 Projected electricity consumption and Scope 2 GHG emissions

Year	ROM (tpa)	Electricity Consumption (MWh/y)	Scope 2 Emissions (t CO_2-e)
2020	270,166	9,980	8,284
2021	409,194	15,116	12,546
2022	2,025,727	74,832	62,111
2023	3,270,131	120,802	100,266
2024	3,118,603	115,204	95,620
2025	3,284,437	121,330	100,704
2026	3,353,014	123,864	102,807
2027	3,409,538	125,952	104,540
2028	3,342,829	123,487	102,495
2029	3,255,743	120,270	99,824
2030	3,409,127	125,937	104,527
2031	3,417,885	126,260	104,796
2032	3,139,055	115,960	96,247
2033	3,155,392	116,563	96,748
2034	2,566,647	94,815	78,696
2035	925,491	34,189	28,377
Total	**42,352,980**	**1,564,562**	**1,298,586**

4.8 Energy production from product coal – Scope 3 emissions

Product coal numbers for the life of the project have been estimated and provided by Tahmoor Coal for this assessment. It is currently anticipated that the majority of product coal (more than 90%) will be used as coking coal which is used in the production of steel. The remainder will be used as thermal coal.

Emissions for Scope 3 energy production from product coal are calculated using a similar equation as that referenced in Section 4.3.1.

$$E_{CO2-e} = \frac{Q \times EC \times EF}{1000}$$

Where:

E_{CO2-e}	=	Emissions of GHG from coal combustion	(t CO_2-e)
Q	=	Quantity of product coal burnt	(t)
EC	=	Energy Content Factor for bituminous coal	(GJ/t)[1]
EF	=	Emission factor for bituminous coal combustion	(kg CO_2-e/GJ)

[1] GJ/t = gigajoules per tonne

Scope 3 emissions have been calculated using the energy content and emission factors from Part 1 of Schedule 1 of the NGER Determination (2008) (as amended 2019) and are presented in Table 4.11.

Table 4.11 Energy production GHG emission factors

Year	Coking Product Coal (tpa)	Thermal Product Coal (tpa)	Scope 3 Emissions (t CO_2-e)
2020	124,039	8,756	363,754
2021	180,828	12,551	529,770
2022	1,206,152	70,660	3,501,846
2023	2,045,763	117,715	5,934,313
2024	2,136,242	109,524	6,164,134
2025	2,434,074	121,420	7,015,311
2026	2,548,531	142,638	7,382,972
2027	2,586,457	162,894	7,537,017
2028	2,532,567	192,414	7,460,163
2029	2,472,526	197,017	7,305,632
2030	2,613,918	192,930	7,685,999
2031	2,663,582	190,949	7,818,277
2032	2,356,696	174,408	6,930,790
2033	2,082,582	136,536	6,081,808
2034	1,633,675	80,579	4,706,233
2035	641,232	29,439	1,841,903
Total	**30,258,864**	**1,940,432**	**88,259,920**

5. SUMMARY OF GHG EMISSIONS

A summary of the annual GHG emissions is provided in Table 5.1.

Table 5.1 Summary of estimated CO_2-e (tonnes) – all scopes

Scope 1 Emissions (t CO_2-e) (based on the power plant operating)							Scope 2 Emissions (t CO_2-e)	Scope 3 Emissions (t CO_2-e)
Year	Diesel	Unleaded Petrol	Methane	SF_6	Post-Mining Activities	Total	Electricity	Energy Production
2020	323	5	218,624	0.3	4,593	223,545	8,284	363,754
2021	489	7	94,628	0.5	6,956	102,082	12,546	529,770
2022	2,423	36	188,448	2.2	34,437	225,347	62,111	3,501,846
2023	3,911	59	600,823	3.6	55,592	660,388	100,266	5,934,313
2024	3,730	56	562,504	3.4	53,016	619,309	95,620	6,164,134
2025	3,928	59	687,207	3.6	55,835	747,033	100,704	7,015,311
2026	4,010	60	673,330	3.7	57,001	734,405	102,807	7,382,972
2027	4,078	61	813,763	3.8	57,962	875,868	104,540	7,537,017
2028	3,998	60	1,249,589	3.7	56,828	1,310,478	102,495	7,460,163
2029	3,894	58	1,351,744	3.6	55,348	1,411,048	99,824	7,305,632
2030	4,077	61	1,293,397	3.8	57,955	1,355,494	104,527	7,685,999
2031	4,088	61	1,044,492	3.8	58,104	1,106,750	104,796	7,818,277
2032	3,754	56	1,052,171	3.5	53,364	1,109,349	96,247	6,930,790
2033	3,774	57	382,693	3.5	53,642	440,168	96,748	6,081,808
2034	3,070	46	483,159	2.8	43,633	529,910	78,696	4,706,233
2035	1,107	17	609,833	1.0	15,733	626,691	28,377	1,841,903
Total	**50,655**	**761**	**11,306,405**	**47**	**720,001**	**12,077,868**	**1,298,586**	**88,259,920**
					Annual average	**754,867**	**81,162**	**5,516,245**

Note: Total values may not always equate to the sum of the numbers shown due to rounding

The relative proportions of the total GHG emissions for each scope is shown in Figure 5.1.

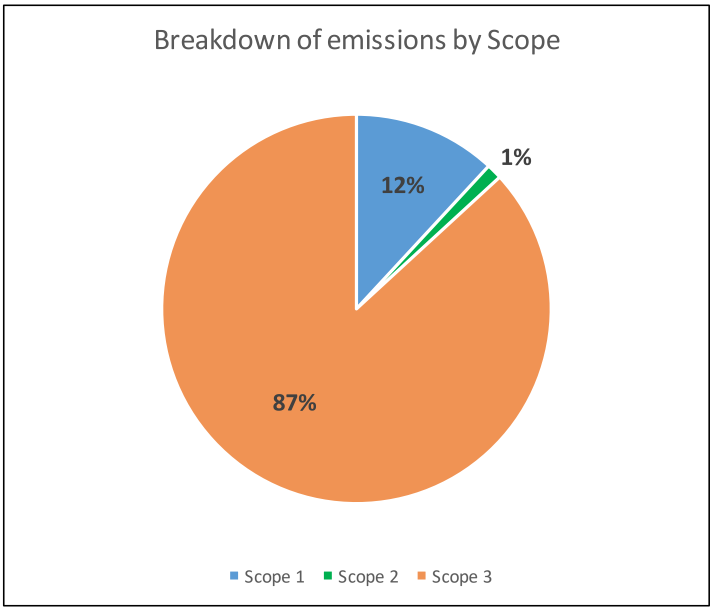


Figure 5.1 Percentage contribution of each scope to total GHG emissions

6. GHG EMISSIONS INTENSITY

The estimated Scope 1 GHG emissions intensity of the Proposal is approximately 0.375 t CO_2 e/t saleable coal. The estimated emissions intensity of the Proposal is comparable with the emissions intensity of existing gassy underground coal mines in Australia (Deslandes, 1999).

Figure 6.1 (derived from Deslandes, 1999) shows the GHG intensity of the Proposal compared to other Australian coal mines. The emissions intensity is within the range for gassy underground mines.

By far the largest source of scope 1 GHG emissions are fugitive methane emissions (92.5%) followed by emissions from post-mining activities (6.0%) (refer Table 5 1).

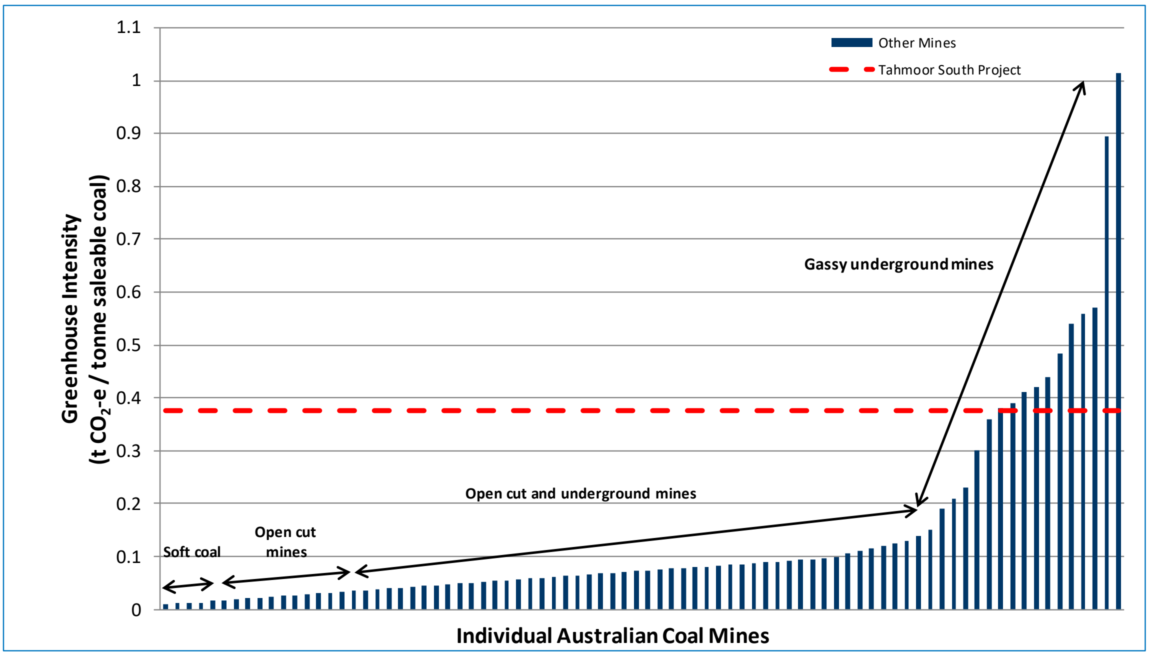


Figure 6.1: GHG intensity comparison

7. ENVIRONMENTAL IMPACT

According to the Intergovernmental Panel on Climate Change's (IPCC) Fifth Assessment Report, global surface temperature has increased by 0.85 [0.65 to1.06]ºC over the period 1880 to 2012 (IPCC, 2014). The IPCC has determined "anthropogenic greenhouse gas emissions have increased since the pre-industrial era, driven largely by economic and population growth, and are now higher than ever" and "their effects, together with those of other anthropogenic drivers, have been detected throughout the climate system and are extremely likely to have been the dominant cause of the observed warming since the mid-20th century" (IPCC 2014). "Extremely likely" is defined by the IPCC as greater than 95% probability of occurrence (IPCC, 2014). It is noted that the Sixth Assessment Report is not due to be issued until 2022.

Climate change projections specific to Australia have been determined by the CSIRO and the Australian Bureau of Meteorology (BoM), based on global emissions scenarios predicted by the latest IPCC assessment (CSIRO, 2015a). These projections supersede those released by CSIRO and the BoM in 2007. Although the findings are similar to those of the 2007 projections, the range of emissions scenarios is broader than those used for the 2007 projections. The latest projections begin with concentration levels, rather than socio-economic assumptions followed by inferred emissions.

The projected changes have been prepared for four Representative Concentration Pathways (RCPs), which represent the following scenarios of emissions of greenhouse gases, aerosols and land-use change:

- RCP8.5 (high emissions) - represents a future with little curbing of emissions, with CO_2 concentrations continuing to rapidly rise, reaching 940 parts per million (ppm) by 2100.
- RCP6.0 (intermediate emissions) - represents lower emissions, achieved by application of some mitigation strategies and technologies. This scenario results in the CO_2 concentration rising less rapidly than RCP8.5, but still reaching 660ppm by 2100.
- RCP4.5 (intermediate emissions) - represents a similar scenario to RCP6.0, but emissions peak earlier (around 2040), and the CO_2 concentration reaches 540ppm in 2100.
- RCP2.6 (low emissions) - assumes a very strong emissions reduction from a peak at around 2020 to reach a CO_2 concentration at about 420ppm by 2100. This pathway would require early participation from all emitters, including developing countries, as well as the application of technologies for actively removing carbon dioxide from the atmosphere.

For climate change projections, a regionalisation scheme using natural resource management regional boundaries has been used to divide Australia up into 8 clusters and 15 sub-clusters. For the projections described above, Table 7.1 presents the changes in annual temperature relative to the 1986-2005 period for the East Coast sub-cluster where the Project is located.

Table 7.1 Projected changes in annual temperature (relative to the 1986-2005 period)

2030 – RCP2.6 (low emissions scenario)	2030 – RCP4.5 (intermediate emissions scenario)	2030 – RCP8.5 (high emissions scenario)	2090 – RCP2.6 (low emissions scenario)	2090 – RCP4.5 (intermediate emissions scenario)	2090 – RCP8.5 (high emissions scenario)
Temperature (ºC)					
0.8 (0.4 to 1.1)	0.9 (0.6 to 1.2)	1.0 (0.6 to 1.3)	0.9 (0.5 to 1.5)	1.9 (1.3 to 2.5)	3.7 (2.7 to 4.7)

Notes: The table gives the median (50th percentile) change with the 10th and 90th percentile range given within brackets.
Source: CSIRO (2015b) Climate Change in Australia – Projections for Australia's NRM Regions – East Coast Cluster Report, Commonwealth Scientific and Industrial Research Organisation.

The CSIRO also details projected changes to other meteorological parameters (for example rainfall, potential evaporation, wind speed, relative humidity and solar radiation) and the predicted changes to the prevalence of extreme weather events (for example droughts, bush fires and cyclones).

The potential social and economic impacts of climate change to Australia are detailed in the Garnaut Climate Change Review (Garnaut, 2008), which draws on IPCC assessment work and the CSIRO climate projections. The Garnaut review details the negative and positive impacts associated with predicted climate change with respect to:

- Agricultural productivity.
- Water supply infrastructure.
- Urban water supplies.
- Buildings in coastal settlements.
- Temperature related deaths.
- Ecosystems and biodiversity.
- Geopolitical stability and the Asia Pacific region

The Project's likely contribution to projected climate change, and the associated impacts of this, would be in proportion with its contribution to global GHG emissions. Average annual scope 1 emissions from the Project (0.75 Mt CO_2-e) would represent approximately 0.175% of Australia's commitment under the Paris Agreement (431 Mt CO_2-e by 2030) and 0.0023% of global GHG emissions (DoEE, 2019; IEA, 2019).

Table 7.2 shows the relative percentage contribution of each different emission scope combination (direct and indirect), to the NSW, Australian and Global GHG emissions. It is noted that combining downstream emissions (Scope 3), adds an element of double counting to the carbon budget if these emissions are captured in the direct (Scope 1) emissions from those downstream operations.

Table 7.2 Project contribution to NSW, Australian and Global GHG emissions

	Annual Project emissions (Mt CO_2-e)	Contribution to total NSW[1] emissions of 128.9 Mt CO_2-e	Contribution to total Australian[2] emissions of 128.9 Mt CO_2-e	Contribution to total Global[3] emissions of 33,100 Mt CO_2-e
Scope 1	0.75	0.586 %	0.175 %	0.0023 %
Scope 1 and 2	0.84	0.649 %	0.194 %	0.0025 %
Scope 1, 2 and 3	6.35	4.93 %	1.47 %	0.0192 %

[1] NSW emissions reported in 2017, taken from the National Greenhouse Gas Inventory (2019) http://ageis.climatechange.gov.au/#

[2] Based on Australia's emission target for 2030 under the Paris Agreement https://climateactiontracker.org/countries/australia/

[3] Latest emissions data available for 2018. https://www.iea.org/geco/emissions/

It can be seen that this Project is a small contributor to the global carbon budget and will also need to be considered with respect to its other environmental impacts, such as visual, amenity and social. Other technical papers will discuss these impacts in detail, however it should be noted that this Project is not a greenfield site but rather an extension of an existing underground operation which has operated at the site since 1979. As such, any potential impacts are not new and have been managed for decades through management plans and community consultation.

More generally the Liberty Steel Group, which Tahmoor Coal is a part of, aims to be carbon neutral by 2030. As part of the GFG Alliance, combining upstream and downstream steel manufacturing, SIMEC is focussed on developing large scale green energy capacity to support their low-carbon metals and industrials strategy, known as GREENSTEEL. Essential for this strategy is low-cost, clean and reliable power supply and a priority is therefore to grow SIMEC's capacity to generate green energy for industry. Existing and pending assets include hydro, wind, water, biodiesel and waste-to-energy technologies.

8. GHG MANAGEMENT AND MITIGATION

8.1 Reasonable and feasible potential management measures and controls

An evaluation has been completed as to what reasonable and feasible measures may be implemented to minimise GHG emissions from the project. A number of options were evaluated to determine those that were feasible from those that were not. Fundamentally, the reduction of fugitive methane emissions by both flaring and, if available, diversion of waste mine gas to a power generation plant (eg, the existing WCMG Power Plant) is considered to be best practice methane management for underground coal mining operations. Given that Tahmoor Coal have determined these practices as both reasonable and feasible, other less effective measures were not evaluated further.

In view of the forgoing, Tahmoor Coal will commit to implementing a number of reasonable and feasible measures to minimise GHG emissions from the Project. Recommended measures are described Table 8.1.

The effectiveness of these reasonable and feasible measures to reduce GHG emissions (and energy consumption) will be monitored, as Tahmoor Coal will annually estimate GHG emissions and energy consumption in accordance with National Greenhouse and Energy Reporting and Energy Efficiency Opportunities requirements.

Table 8.1 Recommended mitigation measures

Type of Mitigation	Description
Creation of mine plan	Maximising energy efficiency is a key consideration in the development of the mine plan. For example, significant savings of GHG emissions (through increased energy efficiency) can be achieved by mine planning decisions which minimise haul distances and therefore fuel use.
Mining operations	Reducing fugitive methane emissions using the following abatement measures: • Flaring. • Methane recycled through third party power generation (eg, the existing WCMG Power Plant), if available. • Use of ventilation control devices in sections of the mine not in use enabling them not to be ventilated (unless required for safety purposes), thereby reducing fugitive emissions). Use of electric winder, not diesel transport, as the primary method of materials transport for the mine. Sealing of panels to reduce methane emissions from the goaf. Use of ventilation control devices in sections of the mine not in use enabling them not to be ventilated (unless required for safety purposes), thereby reducing fugitive emissions.
Monitoring	Use of real-time gas (methane and carbon dioxide), temperature, pressure and associated volumetric flow monitoring at the ventilation shaft site to allow accurate measurement of ventilation (including methane and carbon dioxide) emissions, which will then allow further feasibility assessment of reuse options. Monitoring options are further detailed in Section 8.2 below.
Recording	Ensuring maintenance, calibration and record keeping is undertaken on the main ventilation shaft and fans to allow calculation of GHG emissions. Maintaining records for monthly electricity use and monthly ROM coal production to allow calculation of GHG emissions.
Management Plans	Prepare an Energy Savings Action Plan in accordance with the Guidelines for Energy Savings Action Plans (DEUS, 2005). The plan will include standards to minimise energy use and GHG emissions from the Project's operations. The plan will include objectives, commitments, procedures and responsibilities for: • Assisting in researching and promoting low emission coal technologies. • Improving energy use and efficiency. • Considering the use of alternative fuels where economically and practically feasible. • Review of mining practices to minimise double handling of materials and ensuring that materials haulage is undertaken using the most efficient routes. • Ongoing scheduled and preventative maintenance to ensure that diesel and electricity powered plants operate efficiently. • Develop targets for GHG emissions and energy use and monitor and report against these. • Implementation of a detailed energy monitoring programme. This would include monitoring the electricity and diesel usage on-site to identify main sources of GHG emissions and apply appropriate reduction mechanisms where possible. • Regular maintenance of diesel powered equipment to ensure operation at peak efficiency. • Conduct baseline study of energy use. • Assess lighting plant efficiency.

8.2 Monitoring

A Continuous Emission Monitoring System (CEMS) is currently in place at the Tahmoor Mine. A similar system will be installed for the Tahmoor South Project.

It is intended that the system meet the requirements of Method 4 (direct measurement of emissions of GHGs) as described within Part 1.3 of the NGER Measurement Determination. Division 1.3.1 of Part 1.3 of the NGERs Determination states that:

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

The system will include various instrumentation located at the upcast vent shafts to measure key parameters including:

- Pressure of the gas stream in kilopascals (kPa);
- Flow rate of the gas stream in cubic metres per second (m3/s);
- Proportion of methane and carbon dioxide in the volume of the gas stream (v/v); and
- Temperature in Kelvin (K).

The above parameters are required to be captured during each measurement time step to calculate the mass emission rates for CH_4 and CO_2 consistent with equation 1.21(1) of the NGER Technical Guidelines.

8.2.1 Standards for continuous emission monitoring

To meet the requirements of Method 4 monitoring within Part 1.3 of the NGER Measurement Determination, the monitoring described above must be conducted in accordance with the following standards:

8.2.1.1 Selection of sampling positions

The location of sampling positions for the CEM equipment in relation to the gas stream must be selected in accordance with one of the following standards:

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

8.2.1.2 Flow rate

Monitoring of the volumetric flow rates of the gas stream must be undertaken in accordance with one of the following standards:

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

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

8.3 Gas concentration

The concentration measurements of methane and carbon dioxide in the gas stream must be undertaken in accordance with one of the following standards:

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

All monitoring equipment should be included within the site’s maintenance management system. This is to ensure that all components of the CEM remain within calibration.

Recommendations made within ACARP report C8061 (Mark et al, 2001) state that equipment should be accurate to 0.05% gas concentration to meet a requirement to report GHG emissions to 5 percent accuracy.

8.4 Management of Scope 3 emissions

The vast majority of coal produced at Tahmoor (94%) is coking coal and sold for Australian domestic, European and Asian steel making. Tahmoor cannot influence direct mitigation of these downstream emissions. The countries that use their product will have their own laws, frameworks and policies in place to govern any mitigation measures for those direct emissions. The majority of customers of Tahmoor Coal coking coal product are signatories to the Paris Agreement.

9. CONCLUSION

ERM has been commissioned by Tahmoor Coal to complete this Greenhouse Gas assessment for the Tahmoor South Project. This assessment forms a component of the Environmental Impact Statement for the Project.

The Project's main source of direct GHG emissions include fugitive methane from mine ventilation, pre and post-drainage and flaring. Other Scope 1 and 2 emissions include diesel, unleaded petrol consumption, post-mining activities, electricity use and use of SF_6. The Scope 3 emissions presented for the Project relate to energy used to produce both thermal and coking coal and have been considered in the Project's contribution to the global carbon budget.

It was found that the Project's likely contribution to projected climate change, would be proportionate with its contribution to global GHG emissions. Average annual Scope 1 emissions from the Project (0.75 million tonnes [Mt] CO_2-e) would represent approximately 0.175% of Australia's commitment under the Paris Agreement and 0.0023% of global emissions. When including all indirect emissions, these percentages are 1.47% (Australia) and 0.0192% (global).

Tahmoor Coal will employ a number of mitigation measures at the Project site to minimise the generation of direct GHG emissions. These measures will include fugitive methane abatement such as the use of flares and, if available, recycling through a power generation plant and Continuous Emissions Monitoring of fugitive emissions.

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