APPENDIX 28

Greenhouse Gas
and Energy
Assessment

Environmental & Social Consultants

GLENCORE

GREENHOUSE GAS AND ENERGY ASSESSMENT

Glendell Continued Operations Project

FINAL

November 2019

GLENCORE

GREENHOUSE GAS AND ENERGY ASSESSMENT

Glendell Continued Operations Project

FINAL

Prepared by
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on behalf of
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Executive Summary

The Glendell Continued Operations Project (the Project) will seek approval to extract approximately 135 Mt of ROM coal through an extension of the existing Glendell Mine. The Glendell Mine forms part of the Mount Owen Complex, located within the Hunter Coalfields in the Upper Hunter Valley of New South Wales (NSW) which is owned and operated by subsidiaries of Glencore Coal Pty Limited (Glencore). The applicant for the Project is Glendell Tenements Pty Ltd, which is a 100% owned subsidiary of Glencore. Approval for the Project will be sought under Part 4 of the *Environmental Planning and Assessment Act 1979* (EP&A Act), which requires the Proponent to prepare an Environmental Impact Statement (EIS) to support the development application for the Project.

This report has been prepared to support the preparation of the EIS, and includes greenhouse gas emission projections, an assessment of climate change impacts and an evaluation of greenhouse gas mitigation options. The scope of the greenhouse gas and energy assessment (GHGEA) includes:

- estimating direct and indirect (Scopes 1, 2 and 3) greenhouse gas emissions associated with the Project
- estimating energy use directly associated with the Project
- qualitatively assessing how the Project's greenhouse gas emissions may impact the environment
- estimating the impact of the Project's emissions on State, national and international greenhouse gas emission targets/policies
- assessing reasonable and feasible measures to minimise the greenhouse gas emissions and ensure energy use efficiency

The GHGEA found that the Project can be associated with the following greenhouse gas emissions.

Greenhouse Gas Emissions over the life of the Project		
	(t CO_2-e)	(%) of total emissions
Scope 1	9,933,000	4.30
Scope 2	458,000	0.20
Scope 3	220,424,000	95.50
TOTAL	**230,814,000**	**100**

The Project is forecast to produce approximately 414,000 t CO_2-e Scope 1 emissions per annum, which is comparable to other Hunter Valley open cut coal mining operations of similar size. The majority of Scope 1 emissions are generated by fugitive emissions and diesel combustion. The Proponent has a direct influence over Scope 1 emissions generated from diesel use, and these emissions will be subject to management and mitigation plans.

The Project is forecast to consume approximately 81,000 GJ of electricity per annum, which will generate approximately 19,000 t CO_2-e of Scope 2 emissions per annum. The Proponent can influence reductions in Scope 2 emissions by driving electricity reduction and efficiency initiatives.

Approximately 9,185,000 t CO_2-e of Scope 3 emissions per annum are estimated to be associated with the Project. The majority of Scope 3 emissions associated with the Project will be generated by third parties who transport and consume coal products. The Proponent has no operational control over Scope 3 emissions, as these emissions are generated by the activities of other organisations.

The Project's greenhouse gas inventory is dominated by Scope 3 emissions. Approximately 95% of the Project's greenhouse gas emissions will occur either upstream or downstream of the Project and outside the direct operational control of the Proponent. Approximately 5% of the greenhouse gases associated with the Project are related to on-site energy use and fugitive emissions (Scope 1 and 2 emissions) (refer to **Figure ES1**).

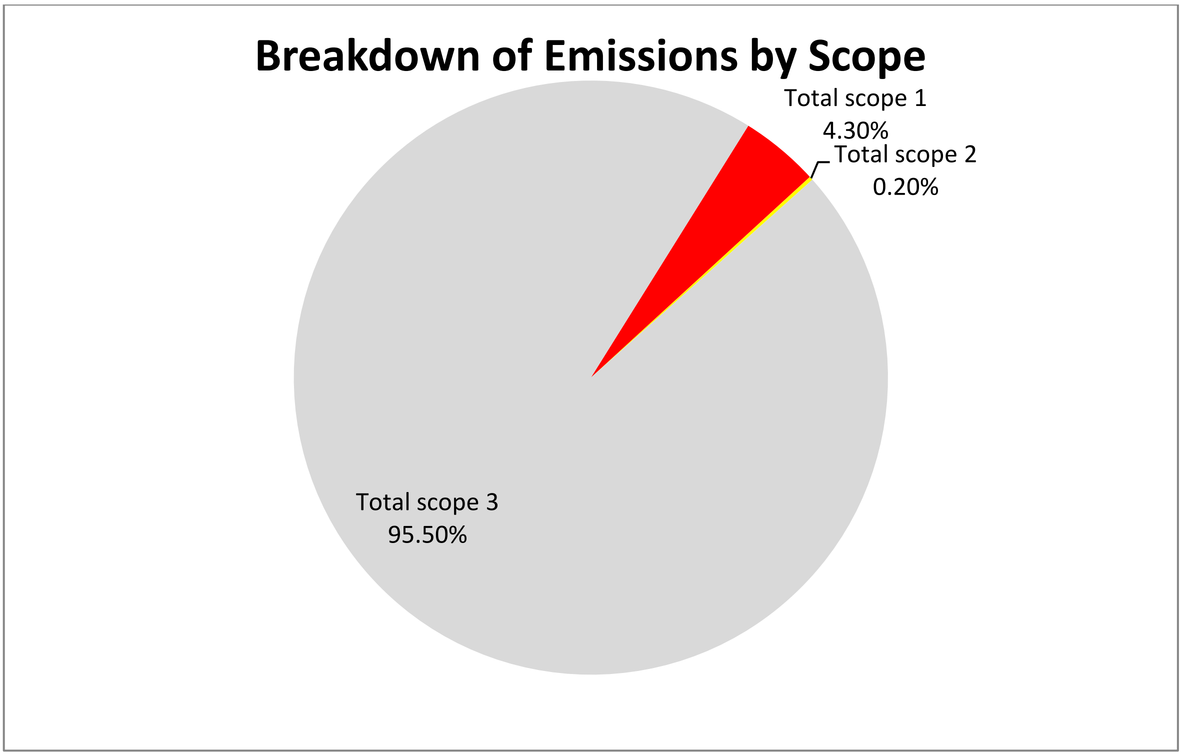

Figure ES1 – Breakdown of Emissions by Scope

Glencore has reviewed the Project's forecasts greenhouse gas emissions inventory, and believes the Project is unlikely to materially increase the national effort required to reach Australia's 2030 greenhouse gas mitigation target. Further, the Project in isolation is unlikely to limit Australia achieving its national mitigation targets.

As part of implementing the Project, the Proponent will seek to mitigate greenhouse gas emissions through ongoing energy efficiency initiatives and optimising productivity.

The Project will contribute to global emissions, however, the extent to which global emissions and atmospheric concentrations of greenhouse gases have a demonstrable impact on climate change will be largely driven by the global response to reducing total global emissions which includes all major emission sources and sinks.

Glencore has announced that it will manage global coal production to a total of around 150 Mtpa going forward as part of a voluntary cap on coal production. However, this does not mean Glencore will freeze its coal projects nor exiting coal. Glencore has indicated that it will continue to develop a pipeline of coal projects assessed against market conditions and project economics and while remaining within the coal production cap.

Glencore also participates and supports a range of low emission technology initiatives that seek to reduce greenhouse gas emissions from mining operations and provide a pathway to reduce emissions from the use of its products.

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1.0 Introduction

The Glendell Mine forms part of the Mount Owen Complex located within the Hunter Coalfields in the Upper Hunter Valley of New South Wales (NSW) (refer to **Figure 1.1**), approximately 20 kilometres (km) north-west of Singleton, 24 km south-east of Muswellbrook and to the north of Camberwell. The Mount Owen Complex is owned and operated by subsidiaries of Glencore Coal Australia Pty Limited (Glencore), the applicant for the development application for the Project is Glendell Tenements Pty Ltd (an entity owned by Glencore).

The Mount Owen Complex also includes Mount Owen Mine, Ravensworth East Mine, a coal handling and preparation plant (CHPP) and coal transport infrastructure.

The Glendell Continued Operations Project (the Project) is a northward extension of open cut mining operations from the existing Glendell Mine. The Project would extend the life of the Glendell Mine to approximately 2044 and allow for the recovery of approximately 135 million tonnes (Mt) of run of mine (ROM) coal.

The Project will necessitate the realignment of Hebden Road, the realignment of Yorks Creek and the relocation of Ravensworth Homestead. The Project will also require the construction of a new mine infrastructure area (MIA) and a heavy vehicle access road. The Project will continue to use the existing Mount Owen Complex CHPP and rail transport facilities and extend the operation of these facilities for the life of the Project.

Figure 1.2 illustrates the key features of the Project.

Table 1.1 includes the key features of the Project that will impact greenhouse gas emissions.

Table 1.1 Key features of the Project that will impact greenhouse gas emissions

Key Feature	Proposed Operations
Mining methods	• Truck and excavator supported by ancillary equipment such as drills, bulldozers, front-end-loaders, etc.
Mine life	• Glendell Mine – to 2044 (Glendell Pit currently approved to 2024)
Total resource recovered	• Approximately 135 Mt ROM coal
Maximum annual production	• Up to 4.5 Mtpa increasing to up to 10 Mtpa ROM coal as production at the other mines in the Mount Owen Complex decline
CHPP production	• Processing at the existing Mount Owen CHPP. Approved throughput of 17 Mtpa ROM coal will remain as approved

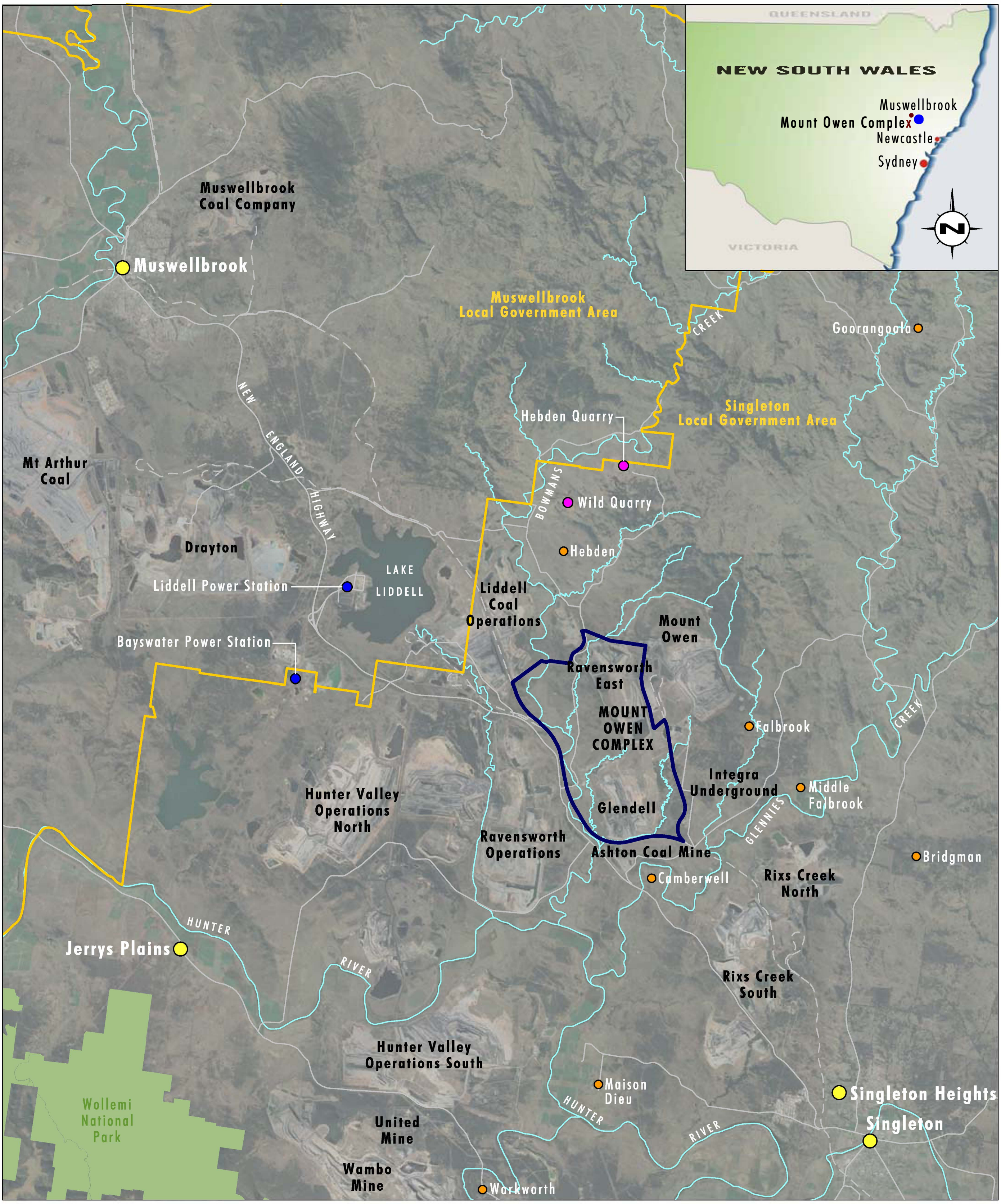

Image Source: Google Earth (2018)
Data Source: Glencore (2019), OEH (2018)

0 2.5 5.0 10km

Legend

- Project Area
- Local Government Area Boundary
- National Park
- Road
- Railway
- Drainage Line
- Towns
- Village/Localities
- Power Stations
- Quarry

FIGURE 1.1

Project Locality

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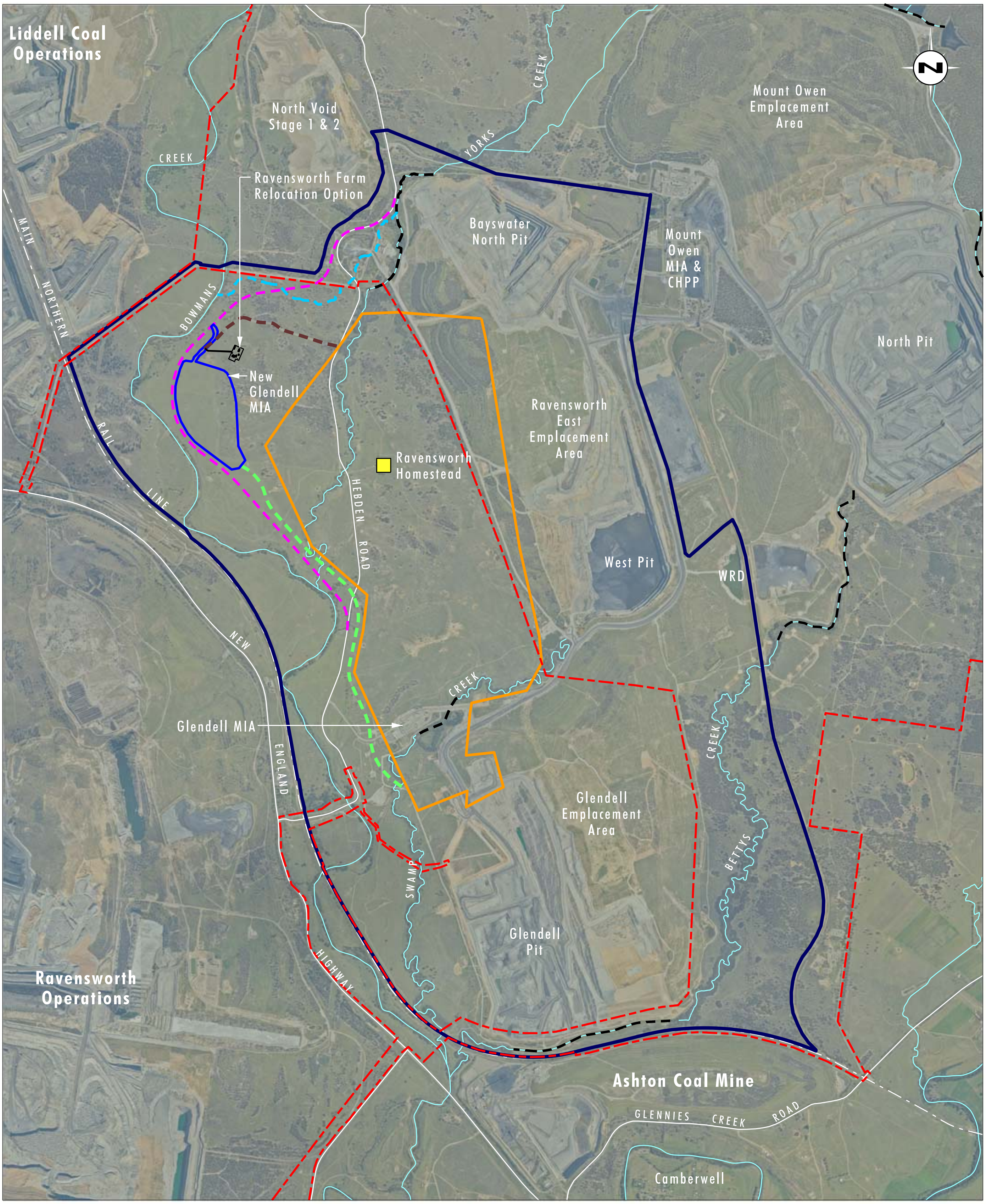

Image Source: Glencore (Dec 2018)
Data Source: Glencore (2019)
Notes: Ravensworth Homestead to be relocated, Mount Owen Consent Boundary assumes Narama Pipeline Modification is approved

0 0.5 1.0 2.0km

Legend

- Project Area
- Glendell Pit Extension
- Mount Owen Consent Boundary
- Ravensworth Homestead
- Existing Creek Diversion
- Construction Access Road

Project Features:

- New Glendell MIA
- Heavy Vehicle Access Road
- Yorks Creek Realignment
- Hebden Road Realignment

FIGURE 1.2

Glendell Continued Operations Project Key Project Features

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2.0 Assessment framework

2.1 Objectives

Approval for the Project will be sought under Division 4.1 of Part 4 of the *Environmental Planning and Assessment Act 1979* (EP&A Act). As a State Significant Development (SSD), an Environmental Impact Statement (EIS) is required to support the development application for the Project.

The objective of this assessment is to evaluate the greenhouse gas and energy use implications of the Project, in a manner that satisfies the Secretary's Environmental Assessment Requirements (SEARs) for the Project. The SEARs for the Project were issued by DPE on 7 June 2018 and reissued on 11 July 2018 and 12 August 2019 which identify the specific requirements to be addressed by the EIS for the Project. The SEARs request *"an assessment of the likely greenhouse gas impacts of the development".*

This report has been prepared to support the preparation of the EIS, and includes greenhouse gas emission projections, an assessment of climate change impacts and an evaluation of greenhouse gas mitigation options.

2.2 Scope

The scope of the GHGEA includes:

- estimating direct and indirect (Scopes 1, 2 and 3) greenhouse gas emissions associated with the Project
- estimating energy use directly associated with the Project
- qualitatively assessing how the Project's greenhouse gas emissions may impact the environment
- estimating the impact of the Project's emissions on State, national and international greenhouse gas emission targets/policies
- assessing reasonable and feasible measures to minimise the greenhouse gas emissions of the Project and ensure energy use efficiency.

2.3 Definitions

Table 2.1 contains concepts and a glossary of terms relevant to this GHGEA.

Table 2.1 Glossary of terms[1]

Concept	Definition
Greenhouse gases	The greenhouse gases covered by the Kyoto Protocol and referred to in this GHGEA include: • Carbon dioxide • Methane • Nitrous oxide • Hydrofluorocarbons • Perfluorocarbons • Sulphur hexafluoride.
Scope 1 emissions	Direct emissions that occur from sources that are owned or controlled by the Project (e.g. fuel use, fugitive emissions). Scope 1 emissions are emissions over which the Project has a high level of control.
Scope 2 emissions	Emissions from the generation of purchased electricity consumed by the Project.
Scope 3 emissions	Indirect emissions that are a consequence of the activities of the Project, but occur at sources owned or controlled by other entities (e.g. outsourced services). Scope 3 emissions can include emissions generated upstream of the Project by providers of energy, materials and transport. Scope 3 emissions can also include emissions generated downstream of the Project by transport providers and product use.

2.4 Impact assessment methodology

The GHGEA framework is based on the methodologies and emission factors contained in the *National Greenhouse Accounts (NGA) Factors* 2018 (DoEE 2018a) (the NGA Factors). The assessment framework also incorporates the principles of *The Greenhouse Gas Protocol: A Corporate Accounting and Reporting Standard* (WRI/WBCSD 2004) (the GHG Protocol).

The GHG Protocol provides an internationally accepted approach to greenhouse gas accounting. The GHG Protocol provides guidance on setting reporting boundaries, defining emission sources and dealing with issues such as data quality and materiality.

Scope 1 and 2 emissions were calculated based on the methodologies and emission factors contained in the NGA Factors 2018 (DEE 2018a). Fugitive emissions have been calculated using the Method 1 approach, as described in the NGA Factors. Gas drilling and testing within the proposed mining area has been undertaken, however an NGER compliant model is yet to be complete and the relevant data in order to apply the Method 2 approach was not available at the time of this assessment.

Scope 3 emissions associated with product transport were calculated based on emission factors contained in the *National GHG Inventory: Analysis of Recent Trends and GHG Indicators* (AGO 2007). Other Scope 3 emissions were calculated using methodologies and emission factors contained in the NGA Factors.

All methodologies and calculations have been made assuming that all operations will continue as described in **Section 1.0**.

[1] The GHG Protocol 2004

2.5 Data sources

The calculations in this report are based on activity data developed by the Proponent during the mine planning process.

Table 2.2 contains the source of activity data.

Table 2.2 Source of activity data used for the assessment

Activity data	Source
Construction materials	Glencore - forecast construction materials
On-site fuel consumption	Glencore - forecast diesel consumption
Electricity consumption	Glencore - historical electricity consumption
Fugitive emissions	Glencore - forecast ROM coal production
Product consumption	Glencore - forecast mine production
Product transport	Umwelt - product transport distances

A detailed description of activity data and calculations are provided in **Appendix A**.

2.6 Assessment boundary

The GHGEA boundary was developed to include all significant Scope 1, 2 and 3 emissions. **Figure 2.1** demonstrates how the assessment boundary interacts with the potential emission sources under the Proponent's operational control and other emission sources associated with the Project.

The assessment has been separated into the following components:

- construction emissions that relate to the Project under the proposed Glendell consent (SSD9349)
- operational emissions that relate to the Project under the proposed Glendell consent (SSD9349)
- operational emissions that relate to the proposed modification of the Mount Owen Consent (SSD5850).

2.7 Data exclusions

The GHG Protocol requires inventory data and methodologies to be relevant, consistent, complete, transparent and accurate. The relevance principle states that the greenhouse gas inventory should appropriately reflect greenhouse gas emissions and serve the decision-making needs of users – both internal and external [to the Project] (WRI/WBCSD 2004).

An open cut coal mine has a number of potential emission sources, however, the dominant emission sources, often targeted by mitigation measures and stakeholders can be summarised as:

- diesel use
- fugitive emissions
- electricity use
- product transport

- product use
- materials use.

The completeness principle states that all relevant emission sources within the chosen inventory boundary need to be accounted for so that a comprehensive and meaningful inventory is compiled (WRI/WBCSD 2004).

The emission sources listed in **Table 2.3** have been excluded from the GHGEA as activity data is not readily available, and modelling activity data for these sources is unlikely to generate sufficient emissions to materially change impacts or influence the decision-making outcomes of stakeholders.

Table 2.3 Data exclusions

Emission source	Scope	Description
Combustion of fuel for energy	Scope 1	Small quantities of fuels such as petrol and LPG.
Industrial processes	Scope 1	Sulphur hexafluoride (high voltage switch gear). Hydrofluorcarbon (commercial and industrial refrigeration).
Waste water handling (industrial)	Scope 1	Methane emissions from waste water management.
Solid waste	Scope 3	Solid waste to landfill.
Business travel	Scope 3	Employees travelling for business purposes.
Employee travel	Scope 3	Employees travelling between their place of residence and the Glendell site.

Greenhouse gas emissions resulting from land use, land use change and forestry (LULUCF) were also excluded from the GHGEA. While it is acknowledged that emissions resulting from LULUCF may be an important emission source for decision makers, the assessment made an assumption that all emissions generated during the land clearing process would be sequestered via rehabilitation plantings.

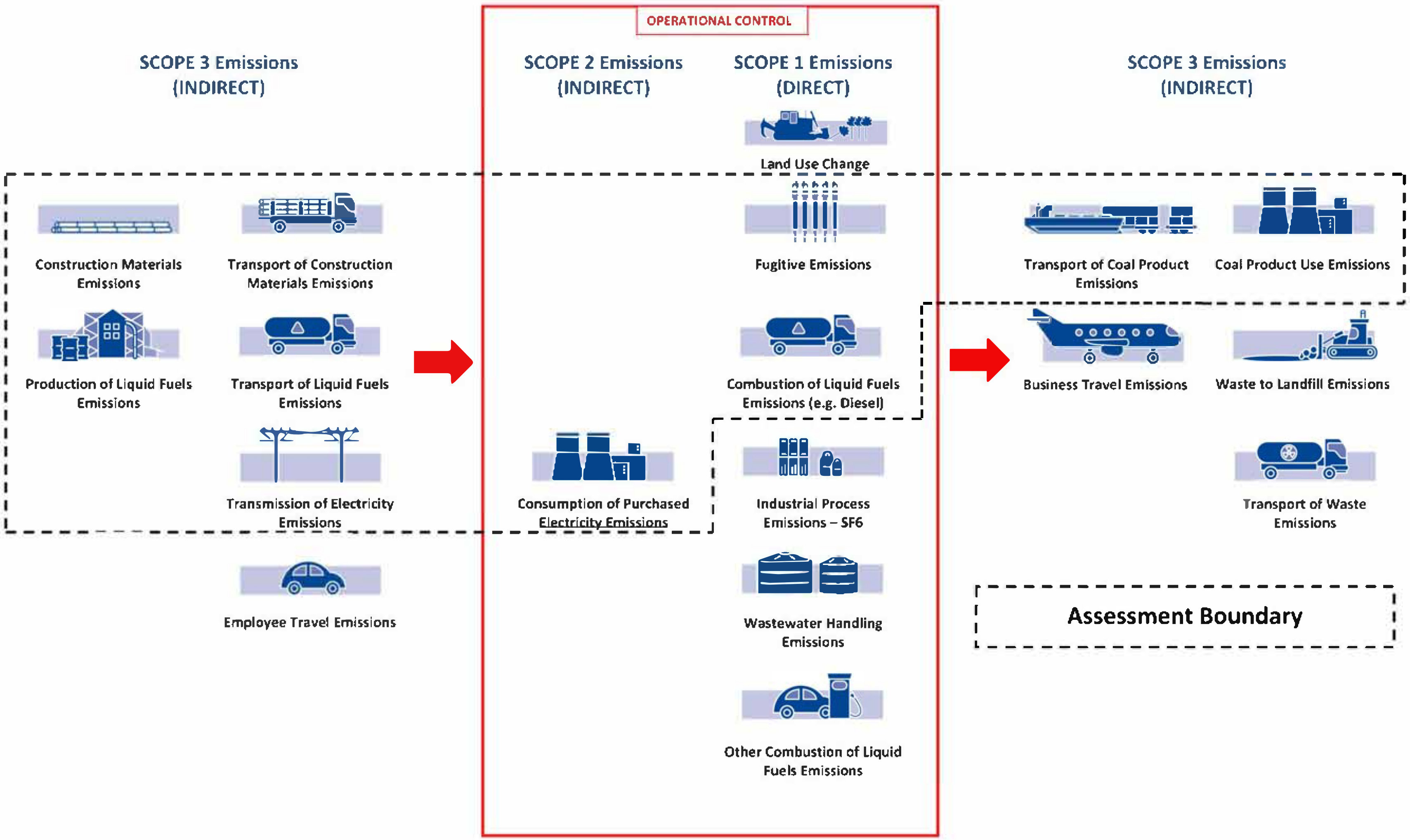

FIGURE 2.1

Greenhouse Gas Assessment Boundary

3.0 Impact assessment results

Greenhouse gas and energy use estimates have been calculated for the construction and operational stages of the Project. As the Project incorporates an application for a new Glendell Development Consent (SSD 9349), and a modification to the approved Mount Owen Development Consent (SSD 5850), the impact results have been separated to demonstrate the potential impact of the individual applications.

The greenhouse gas forecasts referenced throughout this document, only relate to the expected impact of the Project (i.e. recovery of an additional 135 Mt of ROM coal). Forecasts in this document do not include forecast emissions from the currently approved operations.

3.1 Glendell Development Consent (SSD 9349)

The Project incorporates both construction and operational activities.

3.1.1 Construction assumptions

A number of construction activities are planned to occur within the first five years of the Project. The GHGEA only considers the major construction activities associated with the Project and does not include ongoing construction associated with operational activities.

Greenhouse gas estimates have been prepared for the construction of the following Project components that were described in **Section 1.0**:

- the realignment of Hebden Road
- the realignment of Yorks Creek
- the relocation of Ravensworth Homestead to Broke (i.e. worst-case scenario)
- the construction of a new MIA
- the construction of a new heavy vehicle access road.

The demolition of the existing MIA has not been included in the assessment as this is already approved as part of the existing operations.

The greenhouse gas emission estimates for the construction phase are based on the following assumptions[2]:

- The existing Hebden Road will be progressively mined through, and all road waste will either be recycled onsite, or used as fill across the Project site.
- Civil construction will source materials from the Project site and suitable quarries in the region.
- The new section of Hebden Road will be approximately 5 km long and include two lanes.
- Diesel use for civil works will average 1.2 litres/Bank Cubic Metre (BCM) handled.

[2] The assumptions have been developed for the purposes of estimating greenhouse gas emissions, and should not be read as a definitive list of on-site construction activities.

3.1.2 Construction greenhouse gas emissions

The Project's construction related greenhouse gas emissions are summarised in **Table 3.1**. The assessment has assumed that all construction related activities will be outsourced to third party contractors. All greenhouse gas emissions associated the construction phase will be Scope 3 emissions and will be generated by third parties combusting energy and generating industrial emissions in the process of producing and transporting construction materials. Scope 3 emissions will also be generated by contractors consuming energy during the construction process. The construction of the Project is forecast to be associated with approximately 14,000 t CO_2-e Scope 3 emissions.

The breakdown of construction related emissions in **Table 3.1** demonstrate that approximately 45% of forecast construction related emissions are attributable to the consumption of construction materials. The consumption of energy during construction contributes 37% of construction emissions, while 18% of construction emissions are attributable to the transport of construction materials (refer to **Table 3.1**) (See **Appendix A** for further detail).

Table 3.1 Greenhouse gas emission summary for the Project

Stage	Scope	Source	Source Totals (t CO_2-e)	Scope Totals (t CO_2-e)
Construction	Scope 3 (Indirect)	Materials use	6,157	13,528
		Diesel use	4,981	
		Materials transport	2,390	
Homestead Relocation	Scope 3 (Indirect)	Diesel use	171	171
Total Emissions for Construction				**13,699**

3.1.3 Construction energy use

The construction related activities of the Project are forecast to require approximately 103,000 Gigajoules (GJ) of energy from diesel.

3.1.4 Operational assumptions

The following information was used to estimate the greenhouse gas emissions from the operational activities associated with the Project.

- approximately 135,000,000 tonnes of ROM coal will be recovered over the life of the Project
- there will be no change to existing mining methods, coal processing or product transport methods
- diesel and explosive consumption will match the mine plan
- electricity use for the new MIA will average approximately 6,500 GJ per annum between 2021 and 2045
- product coal quality will average approximately 27.5 GJ/tonne and has been classified as Bituminous Coal to align with the NGA Factors
- 100% of all product coal will be exported

- fugitive emissions will average approximately 0.054 t CO2-e / ROM coal tonne (i.e. the default emissions factor for coal mines in NSW). NOTE: Gas drilling and testing within the proposed mining area has been undertaken, however an NGER compliant model is yet to be complete and the relevant data in order to apply the Method 2 approach was not available at the time of this assessment. However, review of the interim fugitive gas models developed for the site (based on gas analysis of sampled bore core) estimate that actual fugitive emissions may be at least four times lower than the default emission factor
- rail transport of product coal will average approximately 92 km
- ship transport of product coal will average approximately 9,500 km.

3.1.5 Operational greenhouse gas emissions

The greenhouse gas emissions associated with the Project are summarised in **Table 3.2** (refer to **Appendix B** for further detail).

Table 3.2 Greenhouse gas emission summary

Stage	Scope	Source	Source Totals (t CO_2-e)	Scope Totals (t CO_2-e)
Operation	Scope 1 (Direct)	Diesel use	2,630,968	9,932,087
		Fugitive emissions	7,301,119	
	Scope 2 (Indirect)	Electricity	37,050	37,050
	Scope 3 (Indirect)	Product use	209,864,104	220,372,162
		Associated with energy extraction and distribution	141,889	
		Product transport	10,354,195	
		Materials transport	11,973	
Total operational emissions associated with the Glendell Continued Operations Project				**230,341,299**

A discussion of the results is provided in **Section 3.3.1**.

3.1.6 Operational energy use

The Project will form part of the Mount Owen Complex, and the Project will generate new energy demands, and share the energy demands of the existing CHPP and MIA. The Project will require diesel for most operational activities and electricity for the new MIA.

The Project is expected to require approximately 38,313,000 GJ.

3.2 Mount Owen Consent (SSD 5850)

3.2.1 Assumptions

The following information was used to estimate the greenhouse gas emissions from the operational activities associated with the modification of the Mount Owen Consent:

- Electricity use will average approximately 205,000 GJ per annum between 2037 and 2045.
- All other electricity use associated with the Project between 2021 and 2036 has not been included in the assessment, as all forecast electricity consumption associated with the Project between 2021 and 2036 has already been assessed as part of the Mount Owen Continued Operations Project (and subsequent modifications)

3.2.2 Greenhouse gas emissions

The greenhouse gas emissions associated with the Mount Owen Consent are summarised in **Table 3.3** (refer to **Appendix B** for further detail).

Table 3.3 Greenhouse gas emission summary

Stage	Scope	Source	Source Totals (t CO_2-e)	Scope Totals (t CO_2-e)
Operation	Scope 2 (Indirect)	Electricity	420,660	420,660
	Scope 3 (Indirect)	Associated with energy extraction and distribution	51,660	51,660
Total operational emissions associated with the Mount Owen Consent				**472,320**

A discussion of the results is provided in **Section 3.3.1**.

3.2.3 Energy use

The electricity use requirements of the Mount Owen Consent (the existing CHPP and MIA) has been assessed and approved (at full operating capacity) up until 2037, as part of the approved Mount Owen Complex Development Consent. The GHGEAs completed for the approved operations have assumed the CHPP would operate a full operational capacity (i.e. 17 Mpta) up until 2037, to create a contingency for additional projects across the Mount Owen Complex. The Project's forecast production fits within the assumptions made for the Mount Owen Complex assessment (i.e. the Project won't inflate the total Complex's processing requirements beyond 17 Mtpa) up until 2037.

From 2037 to 2045 the Project will generate new electricity demands beyond those already assessed as part of the approved operations. The proposed Mount Owen Modification is expected to require approximately 1,845,000 GJ.

3.3 Total project operations

The following sections incorporate the results presented in **Sections 3.1** and **3.2** to present the total operational emissions and energy use associated with the Project.

3.3.1 Greenhouse gas emissions

The total greenhouse gas emissions associated with the Project are summarised in **Table 3.4** (refer to **Appendix B** for further detail).

Table 3.4 Summary of total project operational greenhouse gas emission

Stage	Scope	Source	Source Totals (t CO_2-e)	Scope Totals (t CO_2-e)
Operation	Scope 1 (Direct)	Diesel use	2,630,968	9,932,087
		Fugitive emissions	7,301,119	
	Scope 2 (Indirect)	Electricity	457,710	457,710
	Scope 3 (Indirect)	Product use	209,864,104	220,423,822
		Associated with energy extraction and distribution	193,549	
		Product transport	10,354,195	
		Materials transport	11,973	
Total operational emissions associated with the Project				**230,813,619**

The Project is forecast to generate approximately 9,933,000 t CO_2-e of Scope 1 emissions from combusting diesel and releasing fugitive emissions. Annual Scope 1 emissions associated with the Project are expected to average approximately 414,000 t CO_2-e per annum (when averaged over the life of the Project). Annual average Scope 1 emission estimates should not be used to benchmark annual performance, as annual emissions will vary significantly due to normal variations in annual activity.

The Project is forecast to be associated with approximately 458,000 t CO_2-e of Scope 2 emissions from consuming electricity. Annual Scope 2 emissions associated with the Project are expected to average approximately 19,000 t CO_2-e per annum (when averaged over the life of the Project)[3].

The Project is forecast to be associated with approximately 220,424,000 t CO_2-e of Scope 3 emissions over the life of the Project. Scope 3 emissions will be generated by third parties who transport and consume coal products.

Figure 3.1 demonstrates that the Project's greenhouse gas inventory is dominated by Scope 3 emissions. Approximately 95% of the Project's greenhouse gas emissions occur either upstream or downstream of the Project. Approximately 5% of the greenhouse gas emissions associated with the Project are related to on-site energy use and fugitive emissions (Scope 1 and 2 emissions).

[3] Annual average electricity consumption has been averaged over 25 years as the Project is likely to process ROM coal for up to 12 months after mining ceases.

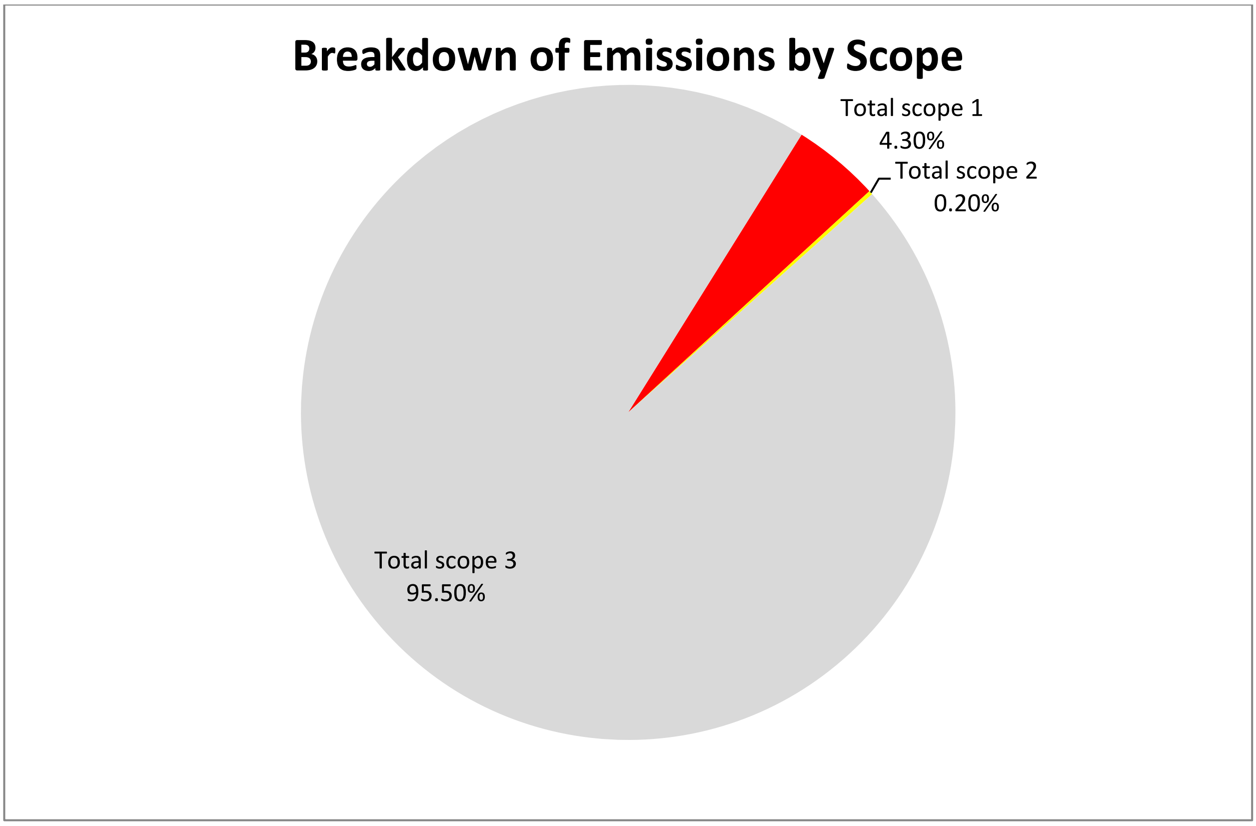

Figure 3.1 Breakdown of emissions by scope

The proportion of Scope 1 emissions forecast for the Project is most likely overstated. The assessment has calculated fugitive emissions based on the default fugitive emissions factor for coal mines in NSW. Interim fugitive gas models developed for the site (based on gas analysis of sampled borecore) estimate that actual fugitive emissions may be at least four times lower than the default emission factor. Operational emissions reported under the National Greenhouse and Energy Reporting Scheme are likely to be reported using a site specific fugitive emission factor (i.e. a Method 2 fugitive emission factor).

Scope 2 and 3 emissions have been included in the GHGEA to demonstrate the potential upstream and downstream impacts of the Project. All Scope 2 and 3 emissions identified in the GHGEA are attributable to, and may be reported by, other sectors.

3.3.2 Energy use

The following energy use has been included in this assessment:

- diesel use associated with recovering approximately 135,000,000 tonne of ROM coal
- diesel use associated with operational activities associated with the Project mine plan (e.g. progressive rehabilitation)
- 100% of the electricity use associated with the new MIA planned for the Project
- 100% of the CHPP operating a full capacity between 2037 and 2045.

The assessment assumptions avoid double counting electricity use across inter-related Development Approvals, and over-estimates electricity consumption between 2037 and 2045 (as the Project will not require the full operational capacity of the CHPP).

The GHGEA has been completed based on the assumption that the Project will consume 40,158,000 GJ of energy from diesel and grid electricity. Energy use associated with the Project is expected to average approximately 1,607,000 GJ per annum (when averaged over the life of the Project).

The industry average energy use for open cut coal mines in Australia ranges between 430 and 660 Megajoules (MJ)/product tonne (AGSO 2000). The forecast energy use intensity associated with the additional coal extracted by the Project is approximately 467 MJ/product tonne, which is at the lower end this range.

4.0 Impact assessment summary

The greenhouse gas emissions generated by the Project have the potential to impact the physical environment and the emission reduction objectives of State, national and international governing bodies. The following assessment makes the distinction between environmental impacts and impacts on policy objectives.

4.1 Impact on the environment

The Project's greenhouse gas emissions will have a disperse impact as they are highly mobile and are generated up and down the supply chain. The accumulation of greenhouse gas or carbon in 'carbon sinks' is the primary impact of emissions. Anthropogenic greenhouse gas emissions have accumulated in three major carbon sinks - the ocean (30%), terrestrial plants (30%) and the atmosphere (40%) (BOM and CSIRO 2014).

The accumulation of greenhouse gas in the atmosphere is an important driver of global warming, sea level rise and climate change (IPCC 2013). Sea level rise and climate change may have many ramifications for the natural and built environment. The accumulation of greenhouse gas in the ocean is also an important driver of ocean acidification (IPCC 2013).

The Project's direct emissions (Scope 1) are forecast to be approximately 414,000 t CO_2 –e per annum.

To put the Project's emissions into perspective, under current policy settings, global greenhouse gas emissions are forecast to reach 56,200,000,000 t CO_2-e per annum by 2025 (UNEP 2016). During operation, the Project will contribute approximately 0.00074 % to global emissions per annum (based on its projected Scope 1 emissions). The relative environmental impact of the Project is likely to be relative to its proportion of global greenhouse gas emissions.

The Scope 2 and 3 emissions associated with the Project should not be considered, as global projections only represent Scope 1 emissions (i.e. the sum of all individual emission sources) as Scope 2 and 3 emissions of the Project are the Scope 1 emission of other parties.

4.2 Impact on climate change

The Intergovernmental Panel on Climate Change (IPCC) define climate change as a change in the state of the climate that can be identified by changes in the mean and/or variability of its properties, and persists for an extended period, typically decades or longer (IPCC 2007).

Climate change is caused by changes in the energy balance of the climate system. The energy balance of the climate system is driven by atmospheric concentrations of greenhouse gases and aerosols, land cover and solar radiation (IPCC 2007).

Climate change models forecast many different climate change impacts, which are influenced by future emission scenarios. Climate change forecasts also vary significantly from region to region.

A qualitative assessment of climate change requires a regional reference and future emission trajectory assumptions. The Project, in isolation, is unlikely to influence global emission trajectories. Future emission trajectories will largely be influenced by global scale issues such as; technology, population growth and greenhouse gas mitigation policy. NSW climate change projections have been modelled by the NSW and ACT Regional Climate Modelling (NARCliM) project. NARCliM has modelled climate change projections for 2030 and 2070, using the IPCC high emissions A2 emission trajectory scenario. The A2 scenario assumes (IPCC 2000):

- relatively slow demographic transition and relatively slow convergence in regional fertility patterns
- relatively slow convergence in inter-regional gross domestic product (GDP) per capita differences
- relatively slow end-use and supply-side energy efficiency improvements (compared to other storylines)
- delayed development of renewable energy
- no barriers to the use of nuclear energy.

The Project is consistent with the A2 emissions trajectory scenario, therefore the climate change projections developed by NARCliM seem a reasonable basis for a qualitative climate change impact assessment. NARCliM makes the following climate change projections for NSW (Adapt NSW 2016):

- maximum temperatures are projected to increase
- minimum temperatures are projected to increase
- the number of hot days will increase
- the number of cold nights will decrease
- rainfall is projected to decrease in spring and winter
- rainfall is projected to increase in summer and autumn
- average fire weather is projected to increase in summer and spring
- number of days with severe fire danger is projected to increase in summer and spring.

The extent to which global emissions and atmospheric concentrations of greenhouse gases have a demonstrable impact on climate change will be largely driven by the global response to reducing total global emissions that includes all major emission sources and sinks.

Glencore has announced that it will manage global coal production to a total of around 150 Mt per annum (pa) going forward as part of a voluntary cap on coal production. However, this does not mean Glencore will freeze its coal projects nor exiting coal. Glencore has indicated that it will continue to develop a pipeline of coal projects assessed against market conditions and project economics and while remaining within the coal production cap.

Glencore also participates and supports a range of low emission technology initiatives that seek to reduce greenhouse gas emissions from mining operations and provide a pathway to reduce emissions from the use of its products

Glencore recognises that over the next 20 years the percentage of the energy generation market supplied by coal is predicted to decline. As the Project meets an existing coal demand and fits within Glencore's committed production cap, Glencore considers that the Project is aligned with the global energy market.

In response to recent commentary and court cases on climate issues related to coal projects has been prepared by Glencore and is attached to the EIS as **Appendix 28**.

4.3 Impact on policy objectives

The United Nations Framework Convention on Climate Change (UNFCCC) is the leading international forum for setting climate change targets and objectives. The UNFCCC has been responsible for developing internationally accepted greenhouse gas emission reporting methodologies, and has led the development of:

- the Kyoto Protocol
- the Paris Agreement
- specific directives and guidance to improve the implementation of the UNFCCC.

The Kyoto Protocol became international policy in 2005, and it committed the European Union (EU) plus 37 other member states to manage greenhouse gas emissions between 2008 and 2012. A second round of the Kyoto Protocol (the Doha Amendment) committed the EU plus 191 other member states to manage greenhouse gas emissions between 2013 and 2020. Australia was a signatory to both rounds of the Kyoto Protocol and Australia will meet its obligations under the Kyoto Protocol in 2020 (DoEE 2018b).

In 2015 the UNFCCC successfully negotiated an international climate change agreement between 195 countries (the Paris Agreement). The Paris Agreement aims to:

- hold the increase in the global average temperature to well below 2°C above pre-industrial levels, and to pursue efforts to limit the temperature increase to 1.5°C above pre-industrial levels
- increase the ability [of nations] to adapt to the adverse impacts of climate change and foster climate resilience and low greenhouse gas emissions development, in a manner that does not threaten food production
- make finance flows consistent with a pathway towards low greenhouse gas emissions and climate-resilient development.

The Paris Agreement seeks to meet its objectives by developing programs and mechanisms that:

- require participating Parties to prepare and communicate greenhouse gas mitigation contributions. Parties are expected to set mitigation targets for 2020, and then develop new targets every five years. Each successive target is expected to represent a larger mitigation effort than the previous target
- promote climate change resilience and adaptation
- provide mitigation and adaptation funding to developing countries
- foster mitigation and adaptation technology transfer between Parties
- require participating Parties to report progress towards their mitigation contributions on an annual basis.

Australia signed the Paris Agreement on 22 April 2016, and Australia's obligations under the Paris Agreement will drive national greenhouse gas policy between 2020 and 2030. Under the Paris Agreement, Australia is obliged to:

- prepare, communicate and maintain a Nationally Determined Contribution (NDC). An NDC outlines the size and type of mitigation contribution each member state will make to the international effort

- pursue domestic mitigation measures, with the aim of achieving the objectives of its NDC
- communicate an NDC every 5 years
- quantify its NDC in accordance with IPCC methodologies, which promote transparency and avoid double counting.

4.3.1 Australian targets

Australia's commitment to the Paris Agreement includes reducing greenhouse gas emissions by 26 - 28 %, on 2005 levels, by 2030 (Commonwealth of Australia, 2015). To meet the requirements of the Paris Agreement, Australia will also have to develop interim targets for 2020 and 2025. Australia's NDC is summarised in **Table 4.1**.

Table 4.1 A summary of Australia's NDC

Emissions reduction target	Economy-wide target to reduce greenhouse gas emissions by 26 to 28 % below 2005 levels by 2030
Coverage	Economy-wide
Scope	Energy Industrial processes and product use Agriculture Land-use, land-use change and forestry Waste
Gases	CO_2, CH_4, N_2O, HFCs, PFCs, SF_6, NF_3

Australia's NDC prescribes an unconditional economy-wide target to reduce greenhouse gas emissions, and states that future policies will target emissions generated from:

- energy use
- industrial processes
- agriculture, land-use, land-use change and forestry
- waste.

Australia's NDC does not contain sector or state based targets, nor does it make any reference to the mining sector.

Glencore has reviewed the Project's forecasts greenhouse gas emissions inventory, and believes the Project is unlikely to materially increase the national effort required to reach Australia's 2030 greenhouse gas mitigation target. Further, the Project in isolation is unlikely to limit Australia achieving its national mitigation targets.

The Project's Scope 2 and 3 emissions will be generated in either international jurisdictions or by Australian facilities with separate environmental approvals to generate greenhouse gas emissions.

4.3.2 NSW Policy

The NSW Government has developed its NSW Climate Change Policy Framework, which aims to deliver net-zero emissions by 2050, and a State that is more resilient and responsive to climate change (OEH 2016).

Under the NSW Climate Change Policy Framework, NSW has committed to both follow the Paris Agreement and to work to complement national action. The key policy directions under the NSW Climate Change Policy Framework are summarised in the **Table 4.2**.

Table 4.2 A summary of the NSW climate change policy framework

Policy Direction	Rationale/Goals
Creating an investment environment that manages the emissions reduction transition	Energy will be transformed and investment/job opportunities will be created in emerging industries of advanced energy, transport and carbon farming and environmental services
Boost energy productivity and put downward pressure on energy bills	Boosting energy and resource productivity will help reduce prices and the cost of transitions to net-zero emissions
Grow new industries and capitalise on competitive advantages	Capitalising on the competitive advantage and growth of industries in professional services, advanced energy technology, property management and financial services
Reduce risks and damage to public and private assets arising from climate change	Embed climate change considerations into asset and risk management as well as support the private sector by providing information and supportive regulatory frameworks for adaptation
Reduce climate change impacts on health and wellbeing	Recognise the increased demand for health and emergency services due to climate change and identify ways to better support more vulnerable communities to health impacts
Manage impacts on natural resources and communities	Coordinate efforts to increase resilience of primary industries and rural communities as climate change impacts water availability, water quality, habitats, weeds and air pollution

The policy framework is being delivered through:

- the Climate Change Fund
- developing an economic appraisal methodology to value greenhouse gas emissions mitigation
- embedding climate change mitigation and adaptation across government operations
- building on NSW's expansion of renewable energy
- developing action plans and strategies.

The Project is unlikely to affect the objectives of the NSW Climate Change Policy Framework in a material way.

5.0 Evaluation of greenhouse gas mitigation measures

This GHGEA is required to assess reasonable and feasible measures to minimise the Project's greenhouse gas emissions.

The term reasonable incorporates notions of costs and benefits, whereas the term feasible focuses on the more fundamental practicalities of the mitigation measures, such as engineering considerations and what is practical to build or operate (Hunter Environment Lobby Inc v Minister for Planning *[2011] NSWLEC 221*).

5.1 Energy efficiency

The Project will mitigate Scope 1 and 2 emissions through energy efficiency initiatives. The energy efficiency of mining operations is driven by energy use and productivity. Energy efficiency is maximised when equipment is operated at optimal capacity. Glencore's mine planning process optimises operational productivity through scheduling, haul road ramp design, haul road design and equipment selection.

5.2 Assessment of potential management measures

The Proponent has incorporated a range of measures into the Project design, with the aim of minimising potential greenhouse gas emissions and improving energy efficiency. Energy efficiency was a key driver for the design of the mine plan as energy usage is a direct driver of cost as well as greenhouse gas emissions. The Project design inherently minimises greenhouse gas emissions generated from the mining operations (i.e. Scope 1 emissions). Key measures included in the Project design to minimise emissions include:

- limiting the length of material haulage routes (where feasible), thus minimising transport distances and associated fuel consumption
- selecting equipment and vehicles that have high energy efficiency
- scheduling activities so that equipment and vehicle operation is optimised.

The following sections assess the Project's planned mitigation measures against best practice greenhouse gas management.

5.2.1 Improving the diesel use efficiency of haul trucks and equipment

Diesel consumption in haul trucks and equipment is forecast to generate approximately 25% of the Project's combined Scope 1 and 2 emissions. **Table 5.1** includes the GHG mitigation measures assessed for improving diesel use efficiency.

Table 5.1 A summary of the NSW climate change policy framework

Energy use during extraction		
Potential Mitigation Measure	**Planned for the Project**	**Reason for Inclusion/Exclusion**
1. Limiting the length of material haulage routes	Yes	Length of haulage routes has been optimised to minimise dust, noise and fuel use
2. Optimising ramp gradients	Yes	Ramp gradients have been optimised according to pit geometry parameters
3. Fuel efficient haul trucks	Yes	Fuel use efficiency has been an important selection criteria when allocating existing trucks to operations. New fuel use technology will be considered should any new trucks be purchased over the life of the Project
4. Payload Management	Yes	Payload will be constantly monitored and actively managed to maintain efficiency
5. Reducing rolling resistance of haul roads	Yes	Haul roads are planned to be constructed of rock rather than of soil or subsoil material. Where practical road materials are selectively sourced which may include crushed rock for use in on-site roads to provide improved road surfaces and reduced rolling resistance
6. Scheduling activities so that equipment and vehicle operation is optimised	Yes	Scheduling activities to optimise plant and vehicle operation is a routine activity. The Proponent will continue to prepare long, medium and short term plans to optimise production
7. Alternative fuels	-	Biodiesel products may be considered with regard to engine performance and maintenance impacts
8. Replacing trucks with conveyors	No	The use of conveyors is not feasible or cost effective given the short haul distances and relatively short life of the Project
9. Fuel efficient equipment	Yes	Fuel use efficiency has been an important selection criteria when allocating existing equipment to operations. New fuel use technology will be considered should any new equipment be purchased over the life of the Project
10. Blasting strategies to improve extraction efficiency	Yes	Through seam blasting will be employed to minimise the need for ripping and parting
11. Maximising resource recovery efficiency	Yes	Long, medium and short term operational plans will be developed to optimise the recovery of approved resources
12. Working machines to their upper design performance	Yes	Glencore's business objectives support and promote effective equipment utilisation and performance rates
13. Electric drills	No	Electric drills are not used at Glendell due to the lack of availability of in-pit supply of electricity and small work areas requiring regular walking of the drills or relocations
14. Preventing unnecessary water ingress	Yes	The surface water management system is designed to maximise separation of clean and dirty water systems. Clean water is diverted away from mining areas where practicable
15. In-pit servicing	Yes	A current operational practice that will continue

Energy use during extraction		
Potential Mitigation Measure	**Planned for the Project**	**Reason for Inclusion/Exclusion**
16. Replace lighting plants with LED	Likely	Glencore has conducted a review of LED lighting plants across its operations and is currently considering the implementation of LED technology
17. Use of chemical dust suppressants to reduce energy consumption by water carts	Yes	Dust suppressants will be used on roads at Glendell

5.2.2 Improving electricity efficiency

Electricity consumption is forecast to generate approximately 5% of the Project's combined Scope 1 and 2 emissions. **Table 5.2** includes the mitigation measures assessed for the CHPP. It is noted that the CHPP is an existing, approved facility and no changes are proposed to this existing facility as part of the Project. Regardless, as the CHPP will be used to process coal from the Project, the Proponent will continue to assess energy efficiency options for the CHPP.

Table 5.2 CHPP energy use options assessed

Energy use during processing		
Potential Mitigation Measure	**Planned for proposed Project**	**Reason for Inclusion/Exclusion**
1. Reducing reject percentage	Yes	CHPP density set points are monitored each shift and product coal scan ash analysers are used to extract highest yield and thus lowest amount of reject
2. Automatically shutting down CHPP when not in use	N/A	CHPP runs 24 hours, 7 days per week other than for maintenance, Christmas and Boxing Days
3. High efficiency motors	Yes	These are installed and will be maintained for the life of the Project
4. Variable Speed Drives	Yes	These are installed and will be maintained for the life of the Project
5. Optimising motor size to load	Yes	This has been implemented at the CHPP
6. LED lighting for the MIA and parking areas	Yes	The new MIA and parking areas constructed for the Project will use LED lighting technology

The Project is planning to utilise many of the common greenhouse gas mitigation measures available for an open cut mine operation. High impact mitigation measures such as pre-draining coal seam methane will not be implemented, as Glencore has determined that this mitigation measure cannot be economically justified.

5.3 The safeguard mechanism

The Project will be subject to the Safeguard Mechanism emission caps which are currently applied to the Glendell Mine. The Safeguard Mechanism sets a maximum emissions cap (a Safeguard Number) for all Australian facilities that emit over 100,000 tonnes CO_2-e per year. If an Australian facility exceeds its Safeguard Number, it is nominally required to offset its exceedance by surrendering Australian Carbon Credit Units to the Clean Energy Regulator (CER).

The current Glendell Mine Safeguard Number is currently set at 448,015 tonnes of CO_2-e, which corresponds to its highest level of emissions between 2009-10 and 2013-14. The Safeguard Mechanism will provide an incentive for the Proponent to manage annual greenhouse gas emissions.

6.0 Scope 3 emissions

Scope 3 emissions are indirect emissions that are associated with the Project, but occur at sources owned or controlled by other entities. Scope 3 emissions simply acknowledge that products will continue to generate greenhouse gas emissions as they move through a value chain. The Project's Scope 3 emissions are forecast to be generated by electricity generators burning coal in countries such as Australia, China, India, Japan, Malaysia, Philippines, South Korea and Taiwan. The Proponent is not seeking approval to generate Scope 3 emissions, as they are not generated by the Project, and approval for Scope 3 emissions has been or will be granted to other parties using other approval pathways.

6.1 Double counting

In assessing the impacts of Scope 3 emissions, it is important not to double count Scope 1 and Scope 3 emissions. Scope 1 and Scope 3 emissions can be the same emissions once greenhouse gas inventories start to capture multiple facilities and entire value chains. For example, the Scope 1 emissions forecast for the Project's consumers are the same emissions as the "Product Use" Scope 3 emissions forecast for the Project.

The classification of different emission scopes was deliberately developed to avoid double counting, and all IPCC level greenhouse gas reporting only considers Scope 1 emissions to avoid double counting. The Katowice Climate Change Package (a UNFCCC initiative developed in December 2018) provides NDC guidance on reporting clarity, transparency and double counting. The importance of avoiding double counting is well-recognised under international and Australian greenhouse gas reporting frameworks. The Paris Agreement, and the subsequent Katowice Climate Change Package, requires member states to:

- avoid double counting consistent with the guidance adopted by the UNFCCC
- apply robust accounting to avoid double counting consistent with the guidance adopted by the UNFCCC
- provide information on how their cooperative approach applies robust accounting to ensure the avoidance of double counting
- avoid double counting when accounting for anthropogenic emissions and removals corresponding to their NDCs.

The NGER Act in Australia does not provide for double counting and only regulates Scope 1 and Scope 2 emissions. There is no requirement or obligation under Australian law to report Scope 3 emissions, as Scope 3 emissions will be captured by the controlling corporations directly responsible for generating emissions (i.e. Scope 1 emissions). The exclusion of Scope 3 emissions from the reporting requirements under Australian law effectively avoids double counting of Scope 3 emissions.

6.2 Uncertainty

The Scope 3 emissions calculated as part of this assessment use default emission factors. The actual emissions generated at the emission source will depend on the technologies employed by electricity generators. For example, if the coal was exported and used in a supercritical coal-fired power station or in conjunction with carbon capture and storage, then the actual GHG emissions would likely be quite different than if used in a conventional power station.

6.3 Management of Scope 3 emissions

Glencore manages a significant product stewardship and market development program which aims to mitigate the downstream impacts of its products.

Glencore supports low-emission coal technology projects via the Australian coal industry's $1 billion COAL21 Fund. Projects supported by this fund include the Callide Oxyfuel project and the Otway Basin Carbon Capture and Storage project.

Separately, Glencore is involved in the following Projects:

- member of the Callide Oxyfuel project in Queensland
- member of the FutureGen CCS project in the USA
- investigating options for carbon capture and storage in Queensland.

Most of the product coal generated by the Project will be exported to countries who are parties to the Paris Agreement. These countries have, or are in the process of developing, domestic laws, policies, and measures to mitigate greenhouse gas emissions (to achieve their NDC targets). The domestic efforts to achieve NDC targets for each market are summarised in **Table 6.1**.

Table 6.1 A Summary of greenhouse gas mitigation policies in major markets

Country	Summary of the domestic climate change framework in the relevant export customer countries
China	• has introduced several policies to limit emissions (including policies to shut down coal-fired power plants, increase the efficiency of its coal generation fleet and place caps on the annual production capacity of coal), and to promote the development of commercially-viable carbon capture, utilisation and storage (CCUS) technology in order to achieve its NDC of lowering carbon intensity by 60 to 65% from 2005 levels • has introduced carbon pricing policies and has committed to extend their scope and value
India	• has imposed a coal tax on all domestic and imported coal since 2010 (which has been increased three times since its inception), though its NDC indicates that coal (from both domestic and imported sources) will continue to dominate power generation into the future and India has included constructing coal-fuelled power plants with higher efficiency.
Japan	• has highlighted carbon pricing and the use of CCUS technologies as key to achieving its emissions reductions NDC of 25% below 2013 levels by 2030 • made significant progress with several CCUS projects • has imposed import taxes for coal and liquefied natural gas (LNG) • aims to pursue high efficiency in thermal power generation using high-efficiency technologies such as ultra-supercritical and advanced ultra-supercritical.
Malaysia	• has set a renewable energy target of 20% by 2025 (an 18% increase from current levels) as a key mechanism for achieving its NDC of reducing emissions by 40% by 2030 relative to 2005 levels • may present an ideal site for CCUS opportunities in the future (though currently lacks the legal and regulatory frameworks to support such projects).

Country	Summary of the domestic climate change framework in the relevant export customer countries
Philippines	• has resolved to increase the share of renewable energy in its generation mix and is considering the introduction of a carbon tax as some of the strategies for meeting its NDC of reducing emissions to approximately 70% below BAU levels by 2030, though has acknowledged that coal will continue to play a key role in the country • plans to continue constructing new coal-fired power plants into the future.
South Korea	• is looking to increase the share of renewable energy and natural gas while decreasing the share of coal as a key measure for achieving its NDC of 37% below business-as-usual (BAU) levels by 2030 • has imposed import taxes for coal and LNG which act as a carbon tax and seeks to encourage a transition away from coal to renewables and LNG
Taiwan	• has legislated toward reducing reliance on both domestic and imported sources of coal, with plans to increase reliance on renewable energy and impose tax mechanisms on imported fossil fuels as a part of its plan to achieving emissions reductions of 50% below BAU levels by 2030 per its NDC.
Vietnam	• has targeted an increase in reliance on renewable energy, while not discounting the continued use of coal, in its plans to reach its NDC of emissions reductions of 8% below BAU by 2030.

The countries that consume the Project's coal (i.e. the primary source of the Project's Scope 3 emissions) have, or will have, numerous domestic laws and policies in place to achieve long term greenhouse gas mitigation. It is both appropriate, and consistent with the overarching international climate change framework, for the Project's Scope 3 emissions to be regulated and reported by the respective export destinations as Scope 1 emissions generated in those countries. Improving the certainty of Scope 3 emissions forecasts requires site based emission factors for every facility that consumes the Project’s products. **Appendix C** also provides a range of technologies that are being employed by key market destinations.

7.0 Conclusion

The Project is a large scale brownfield operation that will produce significant energy commodities over 24 years. The Project's forecast energy use intensity is considered to fall within the normal range when compared with coal mining operations across Australia. The Project is expected to generate approximately 10,390,000 t CO_2-e of Scope 1 and 2 emissions.

The Project is also forecast to be associated with approximately 220,424,000 t CO_2-e of Scope 3 emissions. The Project's Scope 3 emissions are beyond the operational control of the Proponent, and the majority of Scope 3 emissions will be generated downstream of the Project, when coal products are combusted by electricity generators and/or coking plants.

The Project may increase the national mitigation effort required to reach Australia's 2030 greenhouse gas mitigation target, however, the Project itself is unlikely to affect the ability for Australia to achieve its national greenhouse gas targets.

The Proponent has incorporated a range of measures into the Project's design to minimise potential greenhouse gas emissions, and improve energy efficiency. Energy efficiency was a key driver for the design of the mine plan as energy usage is a direct driver of cost as well as greenhouse gas emissions. The Project's design inherently minimises greenhouse gas emissions from the mining operations, primarily through energy use reduction initiatives and maximising the utilisation of existing infrastructure.

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APPENDIX A

Construction Calculations

The greenhouse gas emissions for the construction phase of the Project are based on the following assumptions. The following assumptions have been used for calculation purposes only and are not meant to describe the exact specifications of the Project.

The assumptions are:

- Concrete will be sourced from Singleton
- Steel will be sourced from Newcastle
- Road base will be sourced locally
- Bulk density of concrete is 2,400 Kg/m^3
- Bulk density of road base and footings is 2,200 Kg/m^3
- Bulk density of asphalt is 2,250 Kg/m^3
- Payload of trucks is 33 tonne
- The relocation of Ravensworth Homestead will require medium sized rigid trucks to complete 2,100 trips to Broke
- The relocation of the Ravensworth Homestead will involve a round trip of 100 km.

Appendix A – Construction Calculations

Construction Materials

Activity Data			Emission Factors[4]	GHG Emissions
Material Type	**Usage**	**Unit**	**t CO_2-e/Unit**	**t CO_2-e**
Steel	585	t	1.95	1,141
40 MPa steel reinforced concrete	5,211	t	0.265	1,381
40 MPa fibre reinforced concrete	6,384	t	0.45	2,873
Steel pipe	59	t	1.94	114
Asphalt	4,839	t	0.071	344
Purlins, Girts and Cladding	150	t	2.03	304
			Total GHG emissions (t CO_2-e)	**6,157**

Energy Use during Construction

Activity Data				Emission Factors Full Life Cycle
Purchased energy	Usage	Units	GJ	kg CO_2-e/GJ
Diesel	1,748	kL	67,488	73.8
				t CO_2-e
			Total GHG emissions (t CO_2-e)	**4,981**

Transport of Materials

Activity Data				Emission Factors Full Life Cycle
Purchased energy	Usage	Units	GJ	kg CO_2-e/GJ
Diesel	835	kL	32,250	74.1
				t CO_2-e
			Total GHG emissions (t CO_2-e)	**2,390**

Relocation of Ravensworth Homestead

Activity Data				Emission Factors Full Life Cycle
Purchased energy	Usage	Units	GJ	kg CO_2-e/GJ
Diesel	59.850	kL	2,310	74.1
				t CO_2-e
			Total GHG emissions (t CO_2-e)	**171**

[4] Emission factors sources from the University of Bath, Inventory of Carbon and Energy (ICE) v2.0, 2011.

APPENDIX B

Operation Calculations

Appendix B – Calculation of Operational Emissions

Stationary Diesel Use

Activity Data	Energy Use		Emission Factors		
			CO_2	CH_4	N_20
kL	GJ/kL	GJ	kg CO_2-e/GJ	kg CO_2-e/GJ	kg CO_2-e/GJ
970,937	38.6	37,478,168	69.9	0.1	0.2
			t CO_2-e	t CO_2-e	t CO_2-e
Breakdown of individual GHG emissions (t CO_2-e)			2,619,724	3,748	7,496
				Total GHG Emissions (t CO_2-e)	**2,630,968**

Fugitive Emissions

Activity Data	Energy Use		Emission Factors		
			CO_2	CH_4	N_20
ROM (t)	-	-	kg CO_2-e/ROM t	kg CO_2-e/ROM t	kg CO_2-e/ROM t
135,205,914	N/A	N/A	N/A	54	N/A
			t CO_2-e	t CO_2-e	t CO_2-e
Breakdown of individual GHG emissions (t CO_2-e)			N/A	7,301,119	N/A
				Total GHG Emissions (t CO_2-e)	**7,301,119**

Electricity - GCOP

Activity Data	Energy Use	Emission Factors		
		CO_2	CH_4	N_20
GJ	GJ	kg CO_2-e / GJ	kg CO_2-e / GJ	kg CO_2-e / GJ
162,500	162,500	228	N/A	N/A
		t CO_2-e	t CO_2-e	t CO_2-e
Breakdown of individual GHG emissions (t CO_2-e)		37,050	N/A	N/A
			Total GHG Emissions (t CO_2-e)	**37,050**

Electricity - MTO

Activity Data	Energy Use	Emission Factors		
		CO_2	CH_4	N_20
GJ	GJ	kg CO_2-e / GJ	kg CO_2-e / GJ	kg CO_2-e / GJ
1,845,000	1,845,000	228	N/A	N/A
		t CO_2-e	t CO_2-e	t CO_2-e
Breakdown of individual GHG emissions (t CO_2-e)		420,660	N/A	N/A
			Total GHG Emissions (t CO_2-e)	**420,660**

Product Use

Activity Data		Energy Production		Emission Factors		
				CO_2	CH_4	N_20
Product	Product (t)	GJ/Product t	GJ	kg CO_2-e/GJ	kg CO_2-e/GJ	kg CO_2-e/GJ
Bituminous coal	86,143,684	27.0	2,325,879,468	90	0.03	0.2
Coking coal	0	30.0	0	91.8	0.02	0.2
				t CO_2-e	t CO_2-e	t CO_2-e
Breakdown of individual GHG Emissions (t CO_2-e)				209,329,152	69,776	465,176
					Total GHG Emissions (t CO_2-e)	**209,864,104**

Extraction, Production and Distribution of Energy Purchased - GCOP

Activity Data		Emission Factors		
		CO_2	CH_4	N_20
Purchased energy	GJ	kg CO_2-e/GJ	kg CO_2-e/GJ	kg CO_2-e/GJ
Diesel	38,149,837	3.6	N/A	N/A
Electricity	162,500	28	N/A	N/A
		t CO_2-e	t CO_2-e	t CO_2-e
Breakdown of individual GHG Emissions (t CO_2-e)		141,889	N/A	N/A
			Total GHG Emissions (t CO_2-e)	**141,889**

Extraction, Production and Distribution of Energy Purchased - MTO

Activity Data		Emission Factors		
		CO_2	CH_4	N_20
Purchased energy	GJ	kg CO_2-e/GJ	kg CO_2-e/GJ	kg CO_2-e/GJ
Diesel	0	3.6	N/A	N/A
Electricity	1,845,000	28	N/A	N/A
		t CO_2-e	t CO_2-e	t CO_2-e
Breakdown of individual GHG Emissions (t CO_2-e)		51,660	N/A	N/A
			Total GHG Emissions (t CO_2-e)	**51,660**

Product Transport

Activity Data				Emission Factors		
				CO_2	CH_4	N_20
Transport mode	Product (t)	Distance (km)	Tonne km (tkm)	kg CO_2-e/tkm	kg CO_2-e/tkm	kg CO_2-e/tkm
Rail - Export	86,143,684	92	7,925,218,928	0.0054	N/A	N/A
Ship - Export	86,143,684	9,500	818,364,998,000	0.0126	N/A	N/A
				t CO_2-e	t CO_2-e	t CO_2-e
Breakdown of individual GHG Emissions (t CO_2-e)				10,354,195	N/A	N/A
					Total GHG Emissions (t CO_2-e)	**10,354,195**

Materials Transport

Activity Data				Emission Factors		
				Scope 1	Scope 3	Full Life Cycle
Transport mode	Usage	Units	GJ	kg CO_2-e/GJ	kg CO_2-e/GJ	kg CO_2-e/GJ
Truck – Diesel (230 km)	3,266	kL	126,068	70.5	3.6	74.1
Truck – Explosives (130 km)	920	kL	35,512	70.5	3.6	74.1
						t CO_2-e
					Total GHG emissions (t CO_2-e)	**11,973**

APPENDIX C

Range of technologies employed by key market destinations

Country	Implementation of HELE, CCUS and other similar technologies[5]
China	• Included high-efficiency coal in its NDCs to the *Paris Agreement*. • China's Ministry of Industry and Information Technology (MIIT) and Finance Ministry released a 2015-2020 Action Plan on the Efficient Use of Coal. • China has set limits on consumption per kWh rate (another approach to measuring efficiency) of <310 grams/kWh by 2020 for large plants and has consistently improved emissions intensity. • Employing HELE coal-fuelled plants in increasing percentages, supporting research and development to develop new HELE technologies and transition its fleet to larger power plants • Implemented multiple measures to accelerate the deployment of CCUS. These include: o widely promoting low-carbon technologies, with an emphasis on carbon capture utilisation and storage (CCUS); o supporting CCUS pilots and Near Zero Carbon Emissions pilots; o providing grant funding for CCUS research projects promoted by the Ministry of Science and Technology; o amending the Environmental Impact Assessment Guidelines to better address CCUS projects; and o establishing a CCUS capacity building project for government officials and researchers directly involved in CCUS. • A significant focus for China is the application of CCUS for enhanced oil recovery (EOR). China has over 20 CCUS for EOR projects at various stages of development. A number of these EOR projects have been, or will be, linked to CCUS plants and designed to capture the CO_2 generated by coal-fired power plants. For example, the Sinopec Shengli Power Plant, located near the Shengli oilfield in the Shangdong province (the second largest oil field in China), currently possesses an integrated CCUS pilot plant which captures 40,000 tons of CO_2 per annum, with a second phase of the CCUS plant currently under construction and intended to capture up to 1 million tons of CO_2 per annum. Once the second phase of the CCUS plant is complete, all captured CO_2 will be used for EOR to increase oil recovery by 10-15%.
India	• Included high-efficiency coal-fuelled power in its NDC under the Paris Agreement. • As of December 2018, 21% of India's coal-fuelled generation capacity was HELE, but at least 83% of planned and under construction capacity is HELE. In the 5 years to 2023, at least 53 GW of HELE generating capacity is expected to come online in India. • Target coal burn for power generation in 2027 is 828 Mt, but this is highly dependent on significant renewables growth. Any renewables shortfall will contribute to increased coal demand. • According to India's NDC, coal will continue to dominate power generation in the future. The Government has introduced the following initiatives to improve the efficiency of coal-fired power plants: o all new, large coal-based generating stations have been required to use highly efficient supercritical technology; o Renovation and Modernisation (R&M) and Life Extension (LE) of existing old power stations is being undertaken in a phased manner; and o approximately 144 old thermal stations have been assigned mandatory targets for improving energy efficiency.
Japan	• A global leader in the application of HELE coal-fueled power plants and built its first USC plant in 1993. • 95% of the country's plants are HELE plants. • Included high-efficiency coal as part of their contributions to the Paris Agreement. • Long-term Low-carbon Vision, published in March 2017, refers to CCUS as a means of achieving emission reductions in the energy sector, as well as centralised/distributed energy management. • According to the Global CCS Institute's Global Status Report 2018, Japan has achieved the following major milestones: o commenced of CO_2 injections at the Tomakomai CCUS facility by Japan CCUS with the Ministry of Economy, Trade and Industry's full support – this is Asia's first full-cycle CCUS hydrogen plant, which will capture more than 300,000 tonnes of CO_2 by 2020; o retrofitted the Toshiba Corporation 49MW Mikawa power plant in Omuta (Fukuoka Prefecture) to accept biomass (in addition to coal) with a carbon capture facility; o launched JPOWER and Chugoku Electric Power Company's Osaki CoolGen facility, a 166 MW oxygen-blown IGCC (integrated gasification combined cycle) plant in Osakikamijima (Hiroshima Prefecture), which will separate and capture CO_2; o completed construction of Toshiba's carbon capture and utilisation (CCU) system at the Saga City Waste Incineration Plant (on Japan's Kyushu Island), using captured CO_2 for algae culture; and o announced (by Kawasaki Heavy Industries) of a Japanese Hydrogen Energy Supply Chain that plans to gasify Australian brown coal in Victoria's Latrobe Valley and transport it by ship to Japan for future decarbonised hydrogen developments.

Country	Implementation of HELE, CCUS and other similar technologies[5]
Malaysia	• Malaysia's NDC has a target to reduce its GHG emissions intensity of GDP by 45% by 2030 relative to the emissions intensity of GDP in 2005. • Post-2015 planned or under construction capacity includes 600 MW subcritical and 4,160 MW of USC HELE. • Plans to achieve a 13% efficiency improvement in 2030. • Has set a renewable energy target of 20% (equivalent to 3,991MW) by 2025. Currently the country only sources 2% of its energy from renewable sources. However, it is intended for the target to be met through various policies and frameworks under the *Energy Efficiency and Conservation Act*, a first draft of which is to be presented to Parliament later this year. • Does not have an integrated CCUS legal framework. A scoping study on CCUS in Malaysia was released by the Global CCS Institute, the Clinton Climate Initiative and the Malaysian Ministry of Energy, Green Technology and Water in January 2011. The study found that CCUS technologies present an opportunity to significantly reduce CO_2 emissions in Malaysia. It also found that Malaysia lacks legal and regulatory frameworks that are capable of being applied to the stages of the CCUS project cycle. Despite this, two commercial-scale CCUS projects are currently underway in Malaysia – the K5 Strategic Technology Project (with a CO_2 processing platform due for installation by 2022) and the TNB Janamanjung Project.
South Korea	• As of December 2018, 83% of South Korea's coal-fuelled generation capacity was HELE and at least 90% of planned and under construction capacity is HELE. In the 5 years to 2023, at least 7 GW of HELE generating capacity is expected to come online in South Korea. • South Korea's NDC indicated that it would subsequently develop a detailed plan to implement its mitigation target. To this end, South Korea released a revised roadmap for achieving the 2030 National Greenhouse Gas Reduction Goal in July 2018 (the Roadmap). The Roadmap sets out sectoral targets, including emission reductions of 24 million tonns in the energy conversion sector (power generation, group energy) through policies to reduce fine dust and promote the use of eco-friendly energy.
Taiwan	• Included HELE in its NDC under the Paris Agreement. • As of December 2018, 31% of Taiwan's coal-fuelled generation capacity was HELE and 2.4 GW of planned and under construction capacity is USC HELE. • Taiwan's EPA established a national CCUS strategic alliance in 2011. This alliance brings together domestic experts from government, academia and industry, for the purpose of developing the technology and regulatory framework required for the commercial use of CCUS technology, with the ultimate goal of achieving widespread use of CCUS technology by 2020. Through the alliance, the Taiwan Cement Corporation (in partnership with the Industrial Technology Research Institute) commissioned the world's first CCUS pilot project in the cement industry in 2013, with the two entities agreeing in 2016 to extend their cooperation on the project.
Philippines	• Included HELE in its INDC under the *Paris Agreement*. • The National Framework Strategy on Climate Change 2010-2022 has a long-term objective of facilitating "the transition towards low greenhouse gas emissions for sustainable development". The Strategy sets Key Result Areas to achieve this long-term objective which, relevantly, relate to energy efficiency and conservation and renewable energy. The Strategy sets a goal of doubling the renewable energy capacity in the country from 4,500MW to 9,000MW by 2030.
Vietnam	• Announced plans to continue the buildout of its HELE coal fleet; before 2010, all coal-fuelled power capacity was based on subcritical technology and the first units using HELE supercritical technology were brought online in the 2010-2014 timeframe with an additional approximately 4,200 MW SC and 1,800 MW USC HELE coal-fuelled power plant capacity projected into the future. • Vietnam does not have an integrated CCUS framework, though the government has previously acknowledged the role that CCUS technology could play in assisting Vietnam to achieve its emissions reduction goals.

[5] The content in this table has been sourced from: S&P Global Platts World Electric Power Plants Database, December 2018; M Wiatros-Motyka, 'An overview of HELE technology deployment in the coal power plant fleets of China, EU, Japan and USA' (December 2016) and I Barnes, 'HELE Perspectives for Selected Asian Countries' (International Energy Agency Clean Coal Centre, May 2018).

APPENDIX D

Glencore statement on capping coal

GLENCORE COAL IN AUSTRALIA

March 2019

GLENCORE

Frequently Asked Questions (FAQ) about Glencore's Climate Change Announcement

Why has Glencore made this climate change announcement?

The announcement reflects the increased focus our shareholders are placing on climate change issues, including a number of shareholders who belong to the Climate Action 100+ initiative.

What is Glencore's position on climate change?

Glencore has a stated public position that acknowledges the science of climate change and the global ambition to transition to a low carbon economy.

What was included in Glencore's climate change statement?

a) Paris Consistent Strategy/Capital Discipline

Glencore has committed to manage our future global coal production capacity broadly to current levels.

From 2020, Glencore will disclose projected reduction of indirect Scope 3 emissions including mitigation efforts such as investment in carbon capture and storage projects.

- Mitigation efforts in relation to Scope 3 emissions should not be interpreted as liability for or offsetting of our Scope 3 or indirect emissions.
- Our Scope 3 indirect emissions are our customers' Scope 1 direct emissions and it is those parties, rather than Glencore, that have the ability to control the extent of those emissions.
- Scope 1 direct emissions are subject to the climate policies and regulation of the jurisdictions in which those emissions occur. It is for that reason that climate policies and regulation do not seek to regulate Scope 3 indirect emissions at the point of extraction.

From 2020, Glencore will disclose how significant capital expenditure and investments align with the Paris Goals. This includes any new investment in fossil fuel assets.

b) Public Scope 1 and 2 Targets

Glencore is on track to achieve its target of reducing direct Scope 1 emission intensity by 5 % (of 2016 levels) by 2020.

From 2020, Glencore will release new longer-term direct Scope 1 and Scope 2 emission reduction targets.

c) Review of Progress

Glencore will report annually on the progress in meeting its climate change objectives.

Every three years Glencore will review changes to Nationally Determined Contributions (NDCs) under the Paris Agreement and other developments to inform our approach to climate change strategy.

d) Alignment with Taskforce on Climate Related Financial Disclosures (TCFD)

Glencore has accepted the recommendations of TCFD and will disclose the metrics, targets, scenarios we use to manage climate related risks and opportunities.

e) Corporate Climate Change Lobbying

Glencore will do a review of its membership in trade associations including consideration of their stated positions on climate change.

What does this mean for Australian coal employees?

The climate change statement will not have an impact on our coal employees nor will any mines shut ahead of schedule as a result of the production cap.

What does manage our future global coal production capacity broadly to current levels mean?

Glencore has a world-class coal mining business and will continue to have a world-class coal mining business. We have indicated that we will manage our coal production to around 150 Mt per annum going forward to align with the stated cap.

We will not be freezing all our coal projects nor are we exiting coal. Glencore will continue to consider acquisitions, divestments, expansions and projects against our investment criteria.

Glencore will continue to develop a pipeline of coal projects assessed against market conditions, project economics and now the coal production cap.

How will the coal production cap work?

The coal production cap applies to both thermal and coking coal production.

The coal production cap applies to Glencore's global attributable coal production.

When examining the coal production cap, we differentiate between:

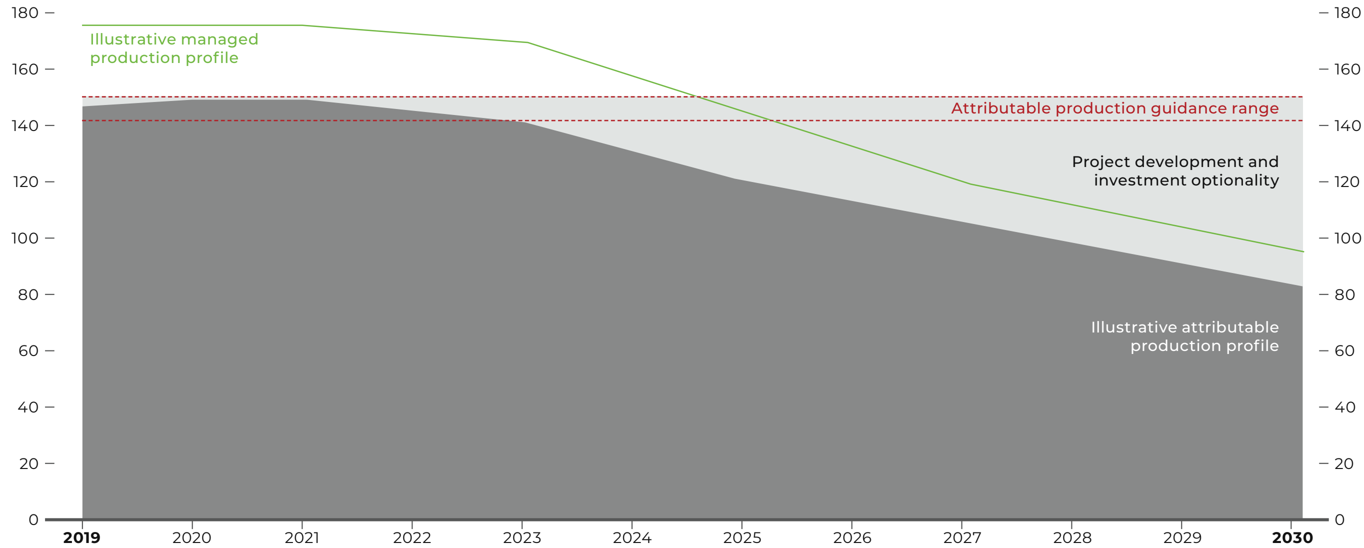
- Managed coal production: which includes the total volume of coal produced from operations in which we have a management role.

  e.g. Joint Ventures like Ravensworth North (Glencore 90% and Itochu 10%) in NSW where Glencore manages operations on behalf of other participants that own a portion of the operation. All of the output of the joint venture is considered to be managed coal production.

GLENCORE COAL IN AUSTRALIA

March 2019

GLENCORE MANAGED AND ATTRIBUTABLE COAL PRODUCTION (Mt)



- Attributable coal production: which includes the volume of coal production in which we have a financial equity interest. For mines that are held in a joint venture ownership structure, Glencore's attributable coal production will be a subset of the managed coal production.

  e.g. Ravensworth North produced 9.1Mt of coal in 2018. Glencore's attributable share in accordance with the Joint Venture agreement is 90% or 8.2Mt.

What's included in the cap and what does this mean for existing coal projects?

All existing mining operations managed by Glencore as at February 2019 are included in the production cap.

It is important to note that the coal production cap has factored in projects currently in the planning phase and planned replacement tonnage from our existing project pipeline.

This includes but is not limited to United Wambo, Glendell North, Mangoola North, Bulga extension and Mt Owen extension.

Does this mean Glencore can't buy new coal assets or start new projects?

No. Glencore can buy new coal assets and commence new projects so long as we manage volumes to remain within the production cap.

The cap also provides the flexibility to acquire interests currently held by joint venture partners in our existing operations.

What does this mean for the Wandoan Coal Project?

The Wandoan Coal Project continues to be under active consideration but we have clearly indicated that market conditions must be appropriate before we will move to develop this resource.

Like any other coal project if or when Wandoan is developed it will need to be managed within the coal production cap.

What is Glencore's global coal production profile to 2030?

The diagram above shows the current coal production profile for Glencore out to 2030 with both the managed production (green line) and attributable production (dark grey section) shown.

Because coal mines extract a finite resource our business needs to continue to develop projects and new mines to simply maintain our current levels of production.

Over time as resources are depleted and mines come to the end of their economic life, without further investment or development of new projects our production levels will decrease. This will create a gap between production levels and the 'cap' which will allow us to make further investments in coal assets, subject to meeting our investment criteria.

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