MINERAL RESOURCES

APPENDIX I

LOCKYER GAS DEVELOPMENT PROJECT: GREENHOUSE GAS ASSESSMENT TECHNICAL REPORT (GREENBASE 2024)

LOCKYER GAS DEVELOPMENT PROJECT

GREENHOUSE GAS ASSESSMENT TECHNICAL REPORT

Version 1.2

Prepared February 2024

Prepared by **Greenbase Pty Ltd**

On behalf of **Mineral Resources Limited**

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Rounding of Amounts

All CO_2-e and energy amounts included in this document have been rounded to the nearest Tonne and GJ respectively, except when rounding would result in a zero.

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Table 1 Document History

Ver.	Date Completed	Details	Name	Status
1.2	19/02/2024	Updated to include emissions from construction activities	Greenbase (H.Ko)	Final v1.2
1.1	11/01/2024	Updated according to the feedback	Greenbase (H.Ko)	Final v1.1
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Table of Contents

Table of Tables

Table of Figures

1 Summary

The Lockyer Gas Development Project (the Project) is intended to be developed with the aim of producing pipeline natural gas to the domestic market in 2026. The Project area is located predominantly within Exploration Permit 368, with potential to expand activities in Exploration Permit 426. The Central Processing Facility (CPF) is located approximately 18 km west of Mingenew, within Lot 3558 on Deposited Plan 232347 with associated infrastructure extending onto Lot 3561 on Deposited Plan 232348. The Project will be located primarily on land previously cleared of native vegetation.

The CPF has a designed capacity of producing 250 terajoules (TJ) of pipeline natural gas per day, intended for export to the domestic market through the Dampier-Bunbury Natural Gas Pipeline (DBNGP). The Project will consist of six conventional gas wells, an upstream gas gathering network, a CPF, a gas export trunkline connecting the CPF to the DBNGP, a condensate stabilisation with associated storage and offloading facility, as well as supporting infrastructure such as power generation, warehousing and workshops, control, equipment and switch room infrastructure and accommodations.

This greenhouse gas (GHG) assessment has been prepared according to the requirements outlined in the Environmental Protection Authority (EPA)'s Environmental Factor Guideline for Greenhouse Gas Emissions (EPA, 2023). The estimated GHG emissions from the Project have been calculated in this assessment.

Based on the assessment, the estimated GHG emissions during the operational phase of the Project are projected to be 78,198 tCO_2-e annually. The GHG emissions anticipated with the construction and land clearing activities have been estimated to be 11,257 tCO_2-e in total.

Scope 3 emissions were examined in this assessment with key emission sources identified as category 3 - fuel and energy related activities, category 9 - downstream transportation and distribution, category 10 - processing of sold products and category 11 – use of sold products. The Scope 3 emissions for these sources during the operational phase are estimated to be 5,172,054 tCO_2-e annually.

Overall, the average GHG emission intensity for the Project was estimated to be 0.8811 tCO_2-e/gigajoule (GJ) of pipeline natural gas produced.

2 Introduction

2.1 Background

The Lockyer Gas Development Project (the Project) is a gas extraction and processing project. The maximum throughput capacity of this project is 250 TJ per annum.

The estimated GHG emissions from the Project, and their likely contribution to regional, state, and national emissions have been calculated in this assessment.

A summary of the project details is outlined in Table 2.

Table 2 Project Summary Table

Project Name	Lockyer Gas Development Project
Proponent Name	Mineral Resources Limited
Relevant Environmental Documents	N/A
Key Environmental factor and objective	Factor: Greenhouse Gas Emissions EPA Environmental Objective: To maintain air quality and minimise emissions so that environmental values are protected. (EPA, 2023)
Proposed commencement date of the Project	Q1 2026

2.2 Lockyer Gas Development Project

The Project area is located predominantly within Exploration Permit 368, with potential to expand activities in Exploration Permit 426. The Central Processing Facility (CPF) is located approximately 18km west of Mingenew, within Lot 3558 on Deposited Plan 232347 with associated infrastructure extending onto Lot 3561 on Deposited Plan 232348 (refer to Figure 1). The Project will be located primarily on land previously cleared of native vegetation.

The Project will extract gas and associated hydrocarbon liquids from the Lockyer and North Erregulla fields. Gas will be produced from conventional wells linked to an upstream gathering network which feeds the CPF. Conditioned gas will be exported to the Dampier-Bunbury Natural Gas Pipeline (DBNGP) for the domestic market. Hydrocarbon liquids will be stabilised for export. The CPF has a designed production capacity of 250 terajoules (TJ) of pipeline natural gas per day. The process diagram of the Project is shown in Figure 2.

The Project will consist of:

- Production wells –six conventional gas wells are envisaged as part of the initial development, with successful exploration and appraisal wells completed to enable their use as producers.
- An upstream gas gathering network connecting the wells to hubs via flowlines in a hub-and-spoke arrangement. Flow from the individual wells (via flowlines) will be aggregated at hubs prior to being directed into larger hub flowlines. In the initial phase the Central and Northern hubs will be developed.
- A CPF to treat the raw gas to the specification required for export to the DBNGP, inclusive of all utilities to support the field operations.

- A gas export trunkline connecting the CPF to the DBNGP.
- A condensate stabilisation, storage, and offloading system to support road transport of the liquid product.
- On-site infrastructure to support the operations phase including power generation, warehousing and workshops, control, equipment and switch room infrastructure and accommodation.

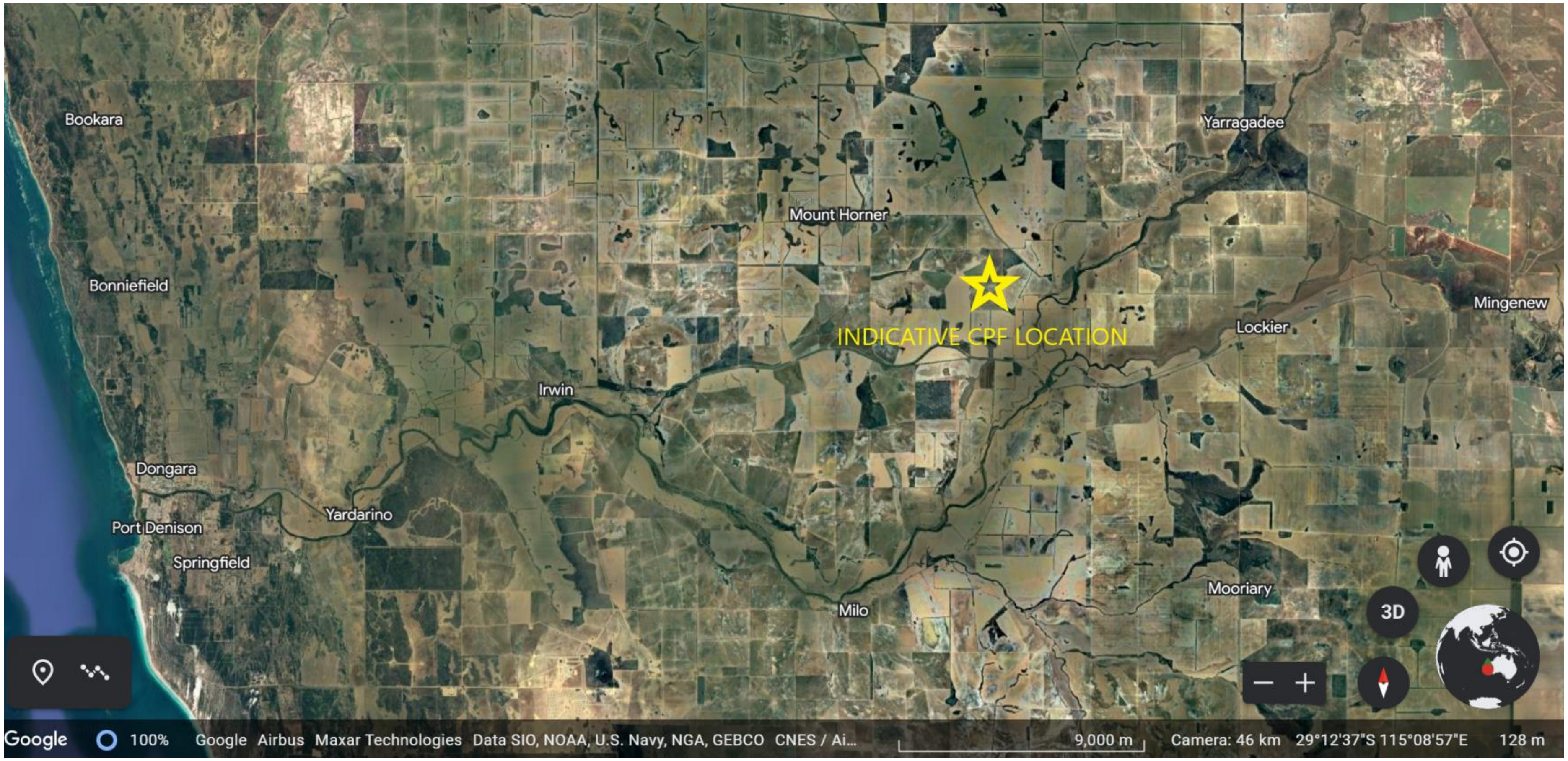


Figure 1 Indicative CPF location (Source: MinRes)

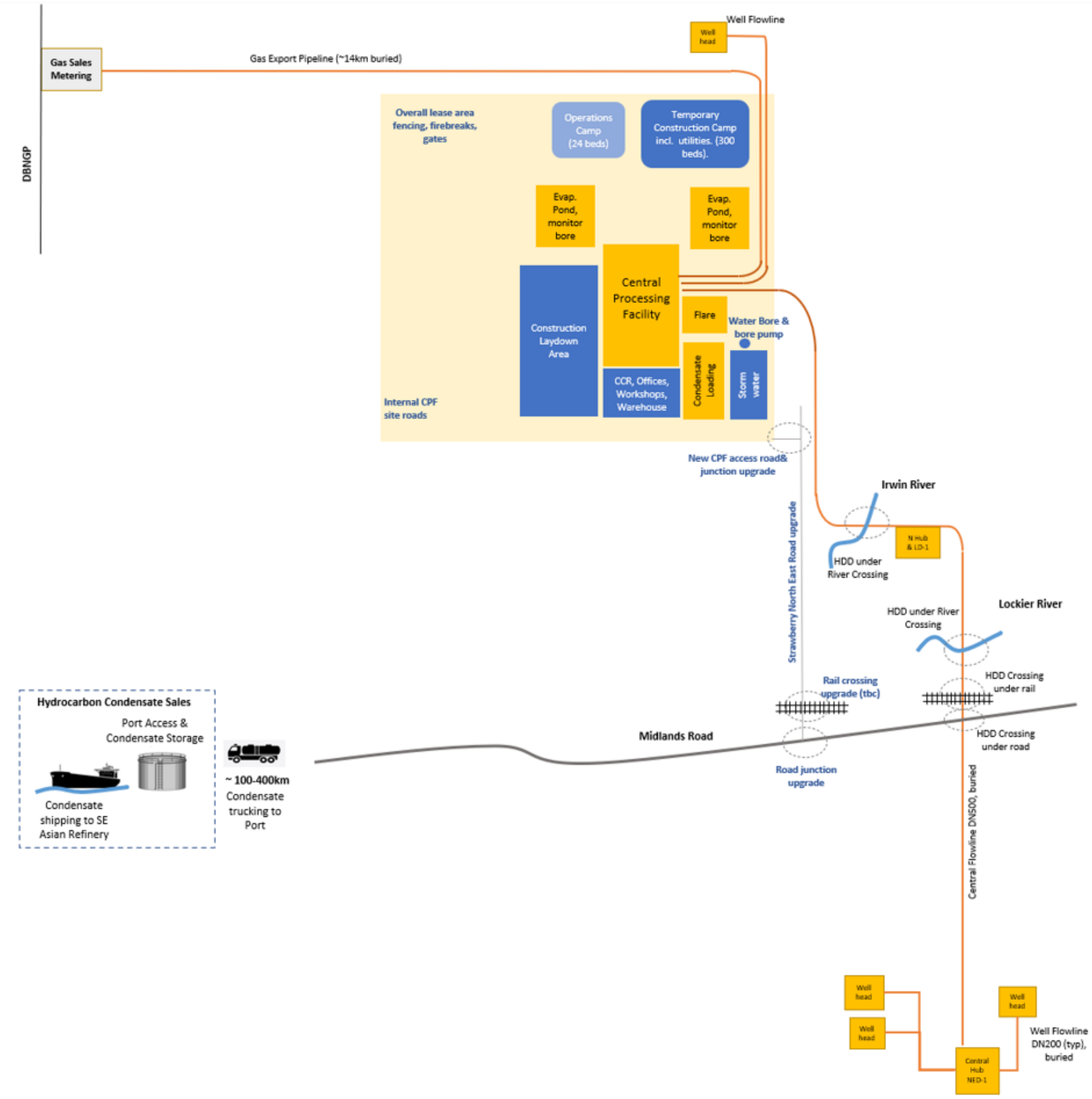


Figure 2 Project Process Diagram (Source: MinRes)

2.3 Australian GHG Landscape

To manage Australia's contribution to global GHG emissions, several frameworks, agreements and policies have recently been put in place. The history and key points of these strategies, which underpin the basis of Australian GHG reporting, are discussed below.

The United Nations Framework Convention on Climate Change (UNFCCC) came into force in 1994 with the aim of stabilising GHG concentrations and preventing dangerous human interference with the climate system (UNFCCC, 2023). Australia, along with over 190 other countries, is a member of this Convention and submits regular reports detailing its annual and quarterly emissions, progress towards targets, projections, and mitigation actions to fulfill its reporting obligations to the UNFCCC. Australia is also a signatory to the Kyoto Protocol, ratified in December 2007, and the Paris Agreement, ratified in November 2016.

The National Greenhouse and Energy Reporting (NGER) scheme, established by the *National Greenhouse and Energy Reporting Act 2007* (NGER Act), is Australia's national framework under which companies are required to report their GHG emissions and energy consumption and production. The objectives of the NGER scheme include informing government policy and helping to meet Australia's international reporting obligations.

In October 2021, Australia set a national net-zero target, while in June 2022 Australia committed to reducing GHG emissions to 43% below 2005 levels by 2030. Alongside this, each state and territory has set their own net-zero target. WA is committed to achieving net-zero emissions by 2050 as outlined in the Western Australian Climate Policy (Government of Western Australia, 2020).

To further align with national and state goals of reducing and managing GHG emissions, the Government of Western Australia published the Greenhouse Gas Emissions Policy for Major Projects (State Emissions Policy) in August 2019. This Policy aims to inform the decision-making process for Environmental Impact Assessments (EIA) assessed by the EPA. Under the Policy, projects with significant GHG emissions (over 100,000 t CO_2-e of Scope 1 emissions per year) are required to demonstrate their ability to contribute to Western Australia's net-zero target. The Environmental Greenhouse Gas Emissions Guideline (EPA, 2023) has been prepared to further inform the EIA process.

2.4 Applicable Environmental Factors

The EPA considers two environmental factors in relation to air, namely Air Quality and Greenhouse Gas Emissions. The objective of each of these environmental factors is outlined below:

- Air Quality - to maintain air quality and minimise emissions (from point sources) so that environmental values are protected.
- Greenhouse Gas Emissions - to reduce net greenhouse gas emissions in order to minimise the risk of environmental harm associated with climate change.

The EPA has also published guidelines on each of these environmental factors, namely the *Air Quality Environmental Factor Guideline* (EPA, 2020) and *Greenhouse Gas Emissions Environmental Factor Guideline* (EPA, 2023). According to the *Greenhouse Gas Emissions Environmental Factor Guideline*, GHG emissions from a proposal will be considered where they are reasonably likely to exceed:

- 100,000 tonnes CO2-e of scope 1 emissions in any year; or
- 100,000 tonnes CO2-e of scope 2 emissions in any year.

This GHG assessment has been prepared to assist the Project in meeting the objective of the EPA's Greenhouse Gas Emissions Environmental Factor Guideline (EPA, 2023), and will not directly address the Air Quality Environmental Factor Guideline (EPA, 2020).

The GHGs included in the Greenhouse Gas Emissions Environmental Factor Guideline are covered by the UNFCCC's Reporting Guidelines on Annual Inventories and are listed below:

- Carbon dioxide (CO_2)
- Methane (CH_4)
- Nitrous oxide (N_2O)
- Sulphur hexafluoride (SF_6)

- Hydro fluorocarbons (HFCs)
- Perfluorocarbons (PFCs).

The main GHG emissions associated with the Project are CO_2, CH_4 and N_2O.

3 GHG Emissions Inventory

3.1 Activities Affecting Key Environmental Factors

The principal activities to be undertaken by the Project have been identified and outlined below:

- Gas and hydrocarbon liquid extraction.
- Gas treatment and processing, including:
  - Power generation,
  - Gas venting,
  - Gas flaring.
- Gas transmission.
- Condensate stabilisation, storage and transportation.
- Other supporting activities including well clean-up, construction of infrastructure and clearing of vegetation.

3.2 GHG Emissions Sources

GHG emissions can include both *direct* and *indirect* emissions, i.e. Scope 1, Scope 2 and Scope 3 emissions. Identified emission sources from the Project are discussed in more detail below.

3.2.1 Scope 1 GHG Emissions

Scope 1 GHG emissions are *direct* emissions from sources within the boundary of the facility or organisation, e.g., fuel combusted on site.

The significant sources of Scope 1 GHG emissions resulting from the activities identified from the Project are as follows:

- Gas venting,
- Gas flaring,
- Diesel and gas consumption by the power station (electricity purposes),
- Fugitive emissions from extraction, gathering, processing and transmission of natural gas and handling of produced water,
- Diesel consumption by the support equipment and other vehicles for construction and land clearing (non-transport purposes), and
- Land clearing (lost carbon sink).

3.2.2 Scope 2 GHG Emissions

Scope 2 GHG emissions are *indirect* emissions from the consumption of purchased electricity, steam or heat produced by another organisation. No Scope 2 emissions are expected from purchased electricity as all electricity will be generated from the onsite power station.

3.2.3 Scope 3 GHG Emissions

Scope 3 GHG emissions are all other *indirect* emissions that are of a consequence of an organisation's activities but are not from sources owned or controlled by the organisation, e.g., the emissions associated with the extraction, refinement, and delivery of diesel to site.

The GHG Protocol (2011) divides Scope 3 GHG emissions into two groups, depending on the financial transactions of the company:

- Upstream indirect GHG emissions related to purchased or acquired goods and services,
- Downstream indirect GHG emissions related to sold goods and services.

Scope 3 GHG emissions are further split into 15 categories to provide a systematic framework for companies to quantify, manage and reduce emissions across their corporate value chain. To avoid double counting emissions, the categories are designed to be mutually exclusive. Table 3 outlines all Scope 3 categories, their relevancy to the project and indicates those included in the GHG assessment. A full list and description of the Scope 3 categories as well as definitions of relevancy are outlined in Appendix A.

Table 3 Scope 3 GHG Emissions Categories (GHG Protocol, 2011)

Category	Relevancy	Included/Excluded in Assessment
1. Purchased goods and services	Not material.	Excluded
2. Capital goods	Not material.	Excluded
3. Fuel- and energy-related activities **(Not included in scope 1 or scope 2)**	**Not material but is directly influenced by the company; should be calculated.**	**Included**
4. Upstream transportation and distribution	Not material.	Excluded
5. Waste generated in operations	Not material.	Excluded
6. Business travel	Not material.	Excluded
7. Employee commuting	Not material.	Excluded
8. Upstream leased assets	Not applicable	Excluded
9. Downstream transportation and distribution	**Material and directly influenced by the company; should be calculated.** **Include the distribution of natural gas, trucking and shipment of condensate from the Port to overseas destinations**	**Included**
10. Processing of sold products	**Material and directly influenced by the company; should be calculated.** **Include the processing of sold condensate**	**Included**

Category	Relevancy	Included/Excluded in Assessment
11. Use of sold products	**Material and directly influenced by the company; should be calculated.** **Include the combustion of sold natural gas and emissions from use of produce made from condensate**	**Included**
12. End-of-life treatment of sold products	Immaterial	Excluded
13. Downstream leased assets	Not applicable, no assets are leased to other companies that are not accounted for in either Scope 1, 2 or other Scope 3 categories.	Excluded
14. Franchises	Not applicable, there are no franchised operations.	Excluded
15. Investments	Not applicable, any investments would come under the larger corporate group and not the site itself.	Excluded

3.3 Limitations and Exclusions

The following emissions and energy sources have been excluded from the assessment as they were deemed either minor sources or no use was identified (exclusions from the Scope 3 are outlined in Table 3):

- Oils and greases,
- Sulphur Hexafluoride (SF_6),
- Hydro fluorocarbons (HFCs) and Perfluorocarbons (PFCs),
- Other minor fuel sources (e.g. ULP), and
- Wastewater treatment plant (WWTP).

Other exclusions are noted below:

- Exploration activities (includes well-testing) is not part of the scope of the Project.

Whilst the estimates in this assessment have been calculated using the best available information, it should be noted that potential for technology change (implementation of best available technology) and updates to costing on the project may result in adjustments to emission estimates.

3.4 GHG Emissions Methodology

3.4.1 Scope 1 GHG Emissions

Scope 1 GHG estimates from all sources of the Project have been prepared using methods and emissions factors from the *National Greenhouse and Energy Reporting (Measurement) Determination 2008 (*NGER Determination), as applicable to 2023-24 financial year (FY2024) reporting.

Fuel Consumption

For emission calculations, fuel use was split into two categories, namely non-transport, and electricity, based on the associated activities.

The emission factors applied to calculations are shown in Table 4. The emission factors are provided in carbon dioxide equivalents (CO_2-e), and therefore include the global warming potential (GWP) of each gas.

Table 4 Diesel and Gas Combustion Emission Factors Applied to the Project

Emission Source	Energy Content Factor	Emission Factor (kgCO_2-e/GJ)			
		CO_2	CH_4	N_2O	Total
Diesel (Non-transport / Electricity)	38.6 GJ/kL	69.9	0.1	0.2	70.20
Natural Gas (Non-transport / Electricity)	0.0393 GJ/m^3	51.4	0.1	0.03	51.53

Fugitive Emissions from Onshore Natural Gas Production

Scope 1 GHG emissions encompass the GHG released during the extraction of gas from associated equipment. Fugitive emissions from onshore natural gas production have been prepared using Method 2 from the NGER Determination. The emission factors used are shown in Table 5.

Table 5 Fugitive Emission Factors from Onshore Natural Gas Production Applied to the Project

Equipment Type	Emissions Factor (tonnes CO_2-e/ equipment-hour)	
	CH_4	CO_2
Gas wellheads	5.04×10^{-4}	1.25×10^{-6}
Gas separators	1.24×10^{-3}	3.08×10^{-6}
Metering installation and associated piping	9.86×10^{-4}	2.45×10^{-6}

Fugitive Emissions from Natural Gas Gathering and Boosting

Scope 1 GHG emissions encompass the GHG released during the natural gas gathering and boosting pipelines from associated equipment. It has been confirmed that there will be piping manifolds only with no gathering and boosting stations. Fugitive emissions from natural gas gathering and boosting pipelines have been prepared using Method 2 from the NGER Determination. The emission factors used are shown in Table 6.

Table 6 Fugitive Emission Factors from Natural Gas Gathering & Boosting Applied to the Project

Equipment Type	Emissions Factor (tonnes CO_2-e/ km of pipeline hour)	
	CH_4	CO_2
Onshore gas gathering and boosting pipelines (protected steel)	1.31×10^{-4}	5.34×10^{-7}

Fugitive Emissions from Produced Water

Scope 1 GHG emissions encompass the methane released when produced water is discharged from the operations. Fugitive emissions from produced water have been prepared using Method 2 from the NGER Determination. The methane emission factor used, for an average pressure of a water stream below 345 kilopascals and average salinity content less than 20,000 mg/L, is 0.8707 tonnes CO_2-e per ML water.

Fugitive Emissions from Natural Gas Processing

Scope 1 GHG emissions encompass the GHG released during the processing of gas from associated equipment. Fugitive emissions from natural gas processing have been prepared using Method 2 from the NGER Determination. The emission factors used are shown in Table 7.

Table 7 Fugitive Emission Factors from Natural Gas Processing Applied to the Project

Equipment Type	Emissions Factor (tonnes CO_2-e/ equipment-hour)	
	CH_4	CO_2
Reciprocating compressors	7.66×10^{-2}	1.91×10^{-4}

Fugitive Emissions from Natural Gas Transmission

Scope 1 GHG emissions encompass the GHG released from natural gas transmission activities. Fugitive emissions from natural gas transmission have been prepared using Method 1 from the NGER Determination. The emission factor specified by the NGER Determination is 0.02 tonnes CO_2-e per kilometre of pipeline annually for carbon dioxide and 11.6 tonnes CO_2-e per kilometre of pipeline annually for methane.

Gas Flaring

Scope 1 GHG estimates from gas flaring have been prepared using Method 1 from the NGER Determination. The emission factors applied to flaring conducted during operations are shown in Table 8. To convert flared gas volume from cubic meters to tonnes, the gas density was calculated using the provided average dry feed gas composition, employing the ideal gas law.

Table 8 Gas and Liquids Flared Emission Factors Applied to the Project

Activities	Emission Source	Emission Factor (tonnes CO_2-e/tonnes fuel flared)			
		CO_2	CH_4	N_2O	Total
Production	Gas	2.7	0.133	0.026	2.859

Gas Venting

Scope 1 GHG estimates from gas venting have been prepared using Method 1 from the NGER Determination. The molar weight and molar volume conversion applied to calculations are shown in Table 9.

Table 9 Molar Weight and Molar Volume Conversion Applied to the Project

Items	Value	Unit
CH_4 Molar Weight	16.040	g/mol
CO_2 Molar Weight	44.010	g/mol
Molar Volume Conversion	23.685	m^3/kgmole@STP

Land Clearing

Lost carbon sink emissions associated with land clearing have been calculated using the Full Carbon Accounting Model (FullCAM) guidelines produced by the Department of Climate Change, Energy, the Environment and Water (DCCEEW, 2020) and methodology outlined in *Carbon Credits (Carbon Farming Initiative—Avoided Clearing of Native Regrowth) Methodology Determination 2015* (CER, 2018). Emissions were calculated by determining the carbon mass (tonnes of carbon per hectare) of the cleared vegetation, multiplying it by the cleared area (hectares), and converting the resulting carbon mass (tonnes of carbon) to CO_2 emissions. It was assumed that all cleared vegetation and debris was converted into CO_2 emissions and released into the atmosphere during the construction period.

The carbon mass (tonnes of carbon per hectare) is calculated using the Project location (latitude/longitude coordinates) and taking consideration of the vegetation type at the areas. The maximum carbon mass of trees per hectare and the associated forest debris carbon mass per hectare have been utilised in the calculations. Other baseline settings used in the FullCAM calculations were set up in accordance with the FullCAM Guidelines (DCCEEW, 2020).

Fuel Combustion from Land Clearing

Fuel combusted from land clearing and grubbing of vegetated areas were estimated using the fuel conversation factors of 0.4 kL per hectare (ha) in the Greenhouse Gas Assessment Workbook for Road Projects (Transport Authorities Greenhouse Group, 2013). Emissions factors shown in Table 4 are used for the emissions estimates.

3.4.2 Scope 3 GHG Emissions

To calculate Scope 3 GHG emissions, the GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard (2011) has been consulted and the GHG Protocol Technical Guidance for Calculating Scope 3 Emissions (2013) referenced where required.

The two main methods of quantifying Scope 3 GHG emissions are direct measurement and calculation. Direct measurement involves monitoring, mass balance or stoichiometry to quantify emissions, while calculation uses an emission factor and activity data to calculate emissions. Due to the difficulty in direct measurement generally the calculation method is used, as such the general formula for calculating emissions is outlined below:

$$GHG\ Emissions = Activity\ Data\ x\ Emisssion\ Factor$$

A variety of emission factor sources were used, including but not limited to:

- National Greenhouse Accounts Factors (2023),
- UK Conversion Factors (2022), and
- Various scientific studies.

When estimating the Scope 3 emissions, fuel-based or goods and distance-based methods are considered the most appropriate options. These methods involve tracking the amount of fuel or goods used and the distance they travel, respectively.

Category 3 – Fuel and Energy-related Activities

Scope 3 emissions from diesel combusted for power generations have been estimated. The emission and energy content factors applied to the calculation of Scope 3 emissions for category 3 are shown in Table 10.

Table 10 Scope 3 Emissions Factor from 'Well to Tank' for Diesel Combustion

Emission Source	Energy Content Factor (GJ/kL)	Emission Factor (kg CO_2-e/GJ)
Diesel combustion	38.6	17.30

Category 9 – Downstream Transportation and Distribution

Scope 3 emissions from category 9 of this Project include:

- Pipeline natural gas distribution from DBNGP to domestic market.

  The fugitive emissions from pipeline natural gas distribution from DBNGP to domestic market have been estimated using Method 1 from the NGER Determination.

- Emissions from diesel combustion from trucking of condensate.

  Diesel combustion from trucking of condensate was estimated. The estimation method relies on the distance travelled by these trucks and the industrial average of fuel rates specific to their type and load capacity. The estimation process factored in the calculated number of trips essential for transporting the condensate to the port of Fremantle for export. Subsequently, the diesel required by these trucks was estimated, and the resulting emissions from diesel combustion were quantified utilising Method 1 from the NGER Determination.

- Emissions from shipping of condensate.

  While the exact destinations of the processing plants couldn't be provided, it has been assumed that the majority of shipments will be to Jurong Island of Singapore as Jurong Island is one of the largest oil refineries in Southeast Asia. It also serves as a geographically central location of the region for estimating purposes. Based on the shipment information provided for the Project, the transportation distance from port of Fremantle to Singapore has been determined.

  Based on the shipment capacity provided for different products, the emission factor for bulk carrier with 10,000 - 59,999 dwt from the UK Conversion Factors (2022) has been utilised for emissions associated with product shipment.

The inputs and factors applied to the calculation of Scope 3 emissions for category 9 are shown in Table 11.

Table 11 Factors and Inputs for Category 9 Scope 3 Emissions Estimates

Emission Sources	Inputs/Factors	Values
Pipeline natural gas distribution from DBNGP to domestic market	% of unaccounted for gas in the pipeline system (WA)	2.9 %
	Natural gas composition factor for natural gas (WA) – CH_4 + CO_2	409.10 tCO_2-e/TJ
Emissions from diesel combustion from trucking of condensate	Travelled distance to port of Fremantle	400 km
	Industrial average of fuel rate for trucks	2.5 km/L
Emissions from shipping of condensate	Distance from departure port to destination port	4110 km
	Emissions factor	0.00921 $kgCO_2$-e/tonne.km

Category 10 – Processing of Sold Product

The process for estimating Scope 3 emissions from processing of sold condensate involved researching representative emission intensities per tonne of products. The estimate utilised an emissions factor of 57.80 kgCO_2-e/bbl, sourced to quantify the emissions associated with this process.

Category 11 – Use of Sold Product

Scope 3 emissions from category 11 of this Project include:

- Emissions from combustion of sold natural gas.

  The exhaust emissions from combusting pipeline natural gas sold have been estimated using Method 1 from the NGER Determination.

- Emissions from use of product made from condensate.

  Research was carried out to obtain the ratio of produced condensate to diesel and gasoline. It was assumed that all condensate shipped was processed and converted into diesel and gasoline. Considering these products were entirely combusted, their associated emissions were estimated using Method 1 as outlined in the NGER Determination.

The inputs and factors applied to the calculation of Scope 3 emissions for category 11 are shown in Table 12.

Table 12 Fuel Combustion Emission Factors for Scope 3 Emissions Category 11 Applied to the Project

Emission Source	Energy Content Factor	Emission Factor (kgCO_2-e/GJ)			
		CO_2	CH_4	N_2O	Total
Diesel (Non-transport / Electricity)	38.6 GJ/kL	69.9	0.1	0.2	70.20
Natural Gas (Non-transport / Electricity)	0.0393 GJ/m^3	51.4	0.1	0.03	51.53
Gasoline (Non-transport / Electricity)	34.2 GJ/kL	67.4	0.6	1.6	69.60

3.5 GHG Emissions Estimates

GHG emissions (scope 1 and 3) have been estimated for the Project's activities when it is in operations (Figure 1). The key inputs used to calculate the scope 1 and 3 GHG emissions associated with the Project are outlined in Table 13. A summary of the estimates is shown in Appendix B.

Table 13 Key Project Inputs

Input	Value
Total Product Produced	Unprocessed gas extracted: 260 MMSCFD Natural gas produced: 88.75 PJ/year (250 TJ/day) Condensate produced: 11.2 Sm^3/h
Operating days per year	355 days
Location	Latitude: -29.210 degree, Longitude: 115.149 degree
Area cleared	15 hectares (Ha)
Total Gas Flared	Operation: - Emergency blowdown: 65,137 Sm^3/year - Other sources: 1,238,827 Sm^3/year
Total Gas Vented	MEG Regeneration: 16,782 Sm^3/year Acid Gas: 11,318,718 Sm^3/year TOX Makeup Gas: 915,604 Sm^3/year
Power Source (Electricity Generation)	On-site diesel and gas
Total Gas Consumption	Gas power generation: 74,952 Sm^3/day
Total Diesel Consumption	Diesel power generation: 116 kg/hr or 134.5 L/hr Diesel for construction: 3,481,200 Litres for 18 months
Gas composition	CH_4 mol%: 87.2 % CO_2 mol%: 3.92 %
Fugitive emissions inputs	
- **Wellheads**	10 wellheads, 10 separators (to account for one surface desander per well), 10 flow meters, all operating 24 hours per day, 355 days per year
- **Gathering system pipelines**	assume 40km of protected steel pipe

Input	Value
- **Produced water**	Produced water produced: 14.1 Sm^3/h Salinity: 15,570 mg/L Pressure: <345 kPa
- **Natural gas processing**	assume 3 x reciprocating compressors operating full time
- **Natural gas transmission pipeline**	14km

3.5.1 Scope 1 GHG Emissions

Fuel Combustion

From the inputs detailed in Table 13 and the methodology described in section 3.4, it is estimated that the Project will create 49,833 tCO_2-e per year of scope 1 GHG emissions from fuel combustion.

The estimated Scope 1 emissions from fuel combustion by gas and diesel generators are outlined in Table 14.

Table 14 Estimated Scope 1 Emissions Associated with Fuel Usage

Sources	Average Annual Emissions (tCO_2-e/year)
Gas combustion (Electricity)	49,720
Diesel combustion (Electricity)	113
Total	**49,833**

Fugitive Emissions from Onshore Natural Gas Production

From the inputs detailed in Table 13 and the methodology described in section 3.4, it is estimated that the Project will create 259 tCO_2-e per year of scope 1 GHG fugitive emissions from onshore natural gas production activities.

Fugitive Emissions from Natural Gas Gathering and Boosting

From the inputs detailed in Table 13 and the methodology described in section 3.4, it is estimated that the Project will create 50 tCO_2-e per year of scope 1 GHG fugitive emissions from natural gas gathering and boosting activities.

Fugitive Emissions from Produced Water

From the inputs detailed in Table 13 and the methodology described in section 3.4, it is estimated that the Project will create 110 tCO_2-e per year of scope 1 GHG fugitive emissions from handling produced water.

Fugitive Emissions from Natural Gas Processing

From the inputs detailed in Table 13 and the methodology described in section 3.4, it is estimated that the Project will create 1,972 tCO_2-e per year of scope 1 GHG fugitive emissions from natural gas processing activities.

Fugitive Emissions from Natural Gas Transmission

From the inputs detailed in Table 13 and the methodology described in section 3.4, it is estimated that the Project will create 163 tCO_2-e per year of scope 1 GHG fugitive emissions from natural gas transmission.

Gas Flaring

From the inputs detailed in Table 13 and the methodology described in section 3.4, it is estimated that the Project will create 3,048 tCO_2-e per year of scope 1 GHG emissions from gas flaring during the operational phase.

Gas Venting

From the inputs detailed in Table 13 and the methodology described in section 3.4, it is estimated that the Project will create 22,764 tCO_2-e per year of scope 1 GHG emissions from gas venting during the operational phase.

The estimated Scope 1 emissions from gas venting breakdown by sources are outlined in Table 15.

Table 15 Estimated Scope 1 Emissions Associated with Gas Venting

Sources	Average Annual Emissions (tCO_2-e/year)
MEG Regeneration	31
Amine AGRU - Acid Gas - TOX Makeup Gas	22,733
Total	**22,764**

Emissions associated with Construction and Land Clearing

From the inputs detailed in Table 13 and the methodology described in section 3.4, it is estimated that the Project will create a total of 9,433 tCO_2-e of scope 1 GHG emissions for the construction activities and 1,824 tCO_2-e of for the land clearing activities. The estimated Scope 1 emissions from construction and land clearing activities are outlined in Table 16.

Table 16 Breakdown Estimated Scope 1 Emissions from Construction Phase

Sources	Total Emissions (tCO_2-e)
Diesel combustion (Construction)	9,433
Diesel combustion (Land Clearance)	16
Land Clearing (Lost carbon sink)	1,808
Total	**11,257**

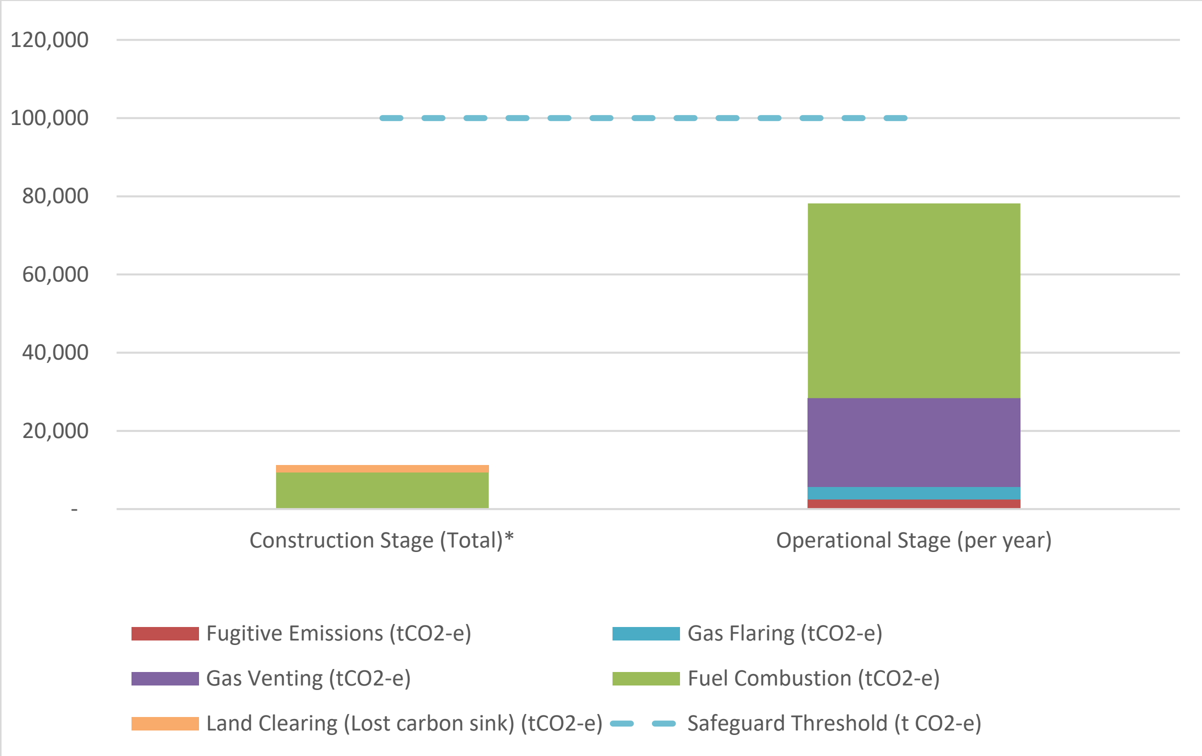
Total Scope 1 GHG Emissions

The emissions calculated from fuel consumption, fugitive emissions, gas flaring and gas venting have been combined to provide an overall estimate of scope 1 GHG emissions. The estimated total scope 1 GHG emissions is 78,198 tCO_2-e per year for the operational phase, and total emissions of 11,257 tCO_2-e from construction and land clearing activities.

A summary of total scope 1 GHG emissions breakdown by source for the Project is outlined in Table 17 and Figure 3.

Table 17 Estimated Total Scope 1 Emissions for the Project

Phase	Category	Total Emissions (t CO2-e)
Construction	Diesel Combustion – Construction	9,433
	Diesel Combustion – Land Clearing	16
	Land Clearing (Lost carbon sink)	1,808
	Total	**11,257**
Phase	**Category**	**Annual Emissions (t CO2-e/year)**
Operational	Fugitive Emissions from Onshore Natural Gas Production	259
	Fugitive Emissions from Natural Gas Gathering & Boosting	50
	Fugitive Emissions from Produced Water	110
	Fugitive Emissions from Natural Gas Processing	1,972
	Fugitive Emissions from Natural Gas Transmission	163
	Emissions from Flaring - Gas Treatment Processed	3,048
	Emissions from Venting	22,764
	Emissions from Exhaust Emissions	49,833
	Total	**78,198**



*The construction will be conducted for 18 months. It has assumed that the land clearing will be conducted during the first year of the construction stage.

Figure 3 Breakdown of Scope 1 Emissions by Source for the Project

3.5.2 Scope 3 GHG Emissions

Scope 3 emissions for the Project have been estimated from the inputs detailed in Table 13 and the methodology described in section 3.4.2.

It is estimated that the Project will create 5,172,054 tCO_2-e of scope 3 GHG emissions annually during operational stage. A summary of total scope 3 GHG emissions breakdown by source for the Project is outlined in Table 18.

Table 18 Estimated Scope 3 Emissions for the Project

Category	Annual Emissions (tCO_2-e/ year)
Category 3 Fuel and Energy Related Activities	28
Category 9 Downstream Transportation and Distribution	397,512
Category 10 Processing of Sold Products	34,472
Category 11 Use of Sold Products	4,740,043
Total	**5,172,054**

4 Benchmark Assessment

4.1 Contribution of the Project GHG emissions

Total estimated emissions of Australia from the Department of Climate Change, Energy, the Environment and Water for the year to December 2022 was 463.9 million tCO_2-e (DCCEEW, 2022). The Clean Energy Regulator (CER) has also published the annual NGER data for FY2022 in March 2023. For the FY2022, registered corporations reported a total of 310 million tCO_2-e of Scope 1 GHG emissions and 84 million tCO_2-e of Scope 2 GHG emissions (CER, 2023). There were 22.2% of Scope 1 GHG emissions contributed from WA (CER, 2023).

To provide a perspective on the project's likely impact, Scope 1 GHG emission estimates of the Project have been compared against regional, state and national emission estimates and displayed in Table 19.

Table 19 Estimated Impact of the Project Scope 1 GHG Emissions

Location	FY2022 Scope 1 GHG Emissions (Million tCO_2-e)	% Contribution from the Project
Western Australia[a]	69	0.11 %
Australia[b]	464	0.02 %

a) Source from Clean Energy Regulator (CER, 2023). Only corporations that trip the NGER reporting thresholds are required to be registered and reported to the NGER Scheme.
b) Source from Quarterly Update of Australia's National Greenhouse Gas Inventory: December 2022 (DCCEEW, 2022).

4.2 Emission Intensity

Emissions intensity was estimated based on production forecasted data and estimated emissions. Emission intensity is calculated by:

$$Emission\ intensity = \frac{Scope\ 1\ emissions}{Natural\ gas\ produced}$$

The Average emission intensity estimated for the Project is 0.8811 tCO_2-e/GJ gas produced.

The estimated emission intensity of the Project was compared with the other oil and gas extraction and processing projects that are:

- Onshore, and
- Producing the same products.

The GHG emission intensities benchmarking comparison for the project is outlined in Table 20.

Table 20 GHG Emission Intensities Benchmark

Project	Natural Gas Production (PJ/year)	Total Scope 1 + 2 Emissions (tCO_2-e /year)	Scope 1 + 2 Emissions Intensity (tCO_2/TJ gas)	Source(s) and notes
MinRes Lockyer Development Project	88.75	78,198	0.88110	From this assessment
Other projects				
AGIO West Erregulla Processing Plant and Pipeline	31.76	96,319[a]	3.03319	West Erregulla Processing Plant and Pipeline Greenhouse Gas Management Plan
MEPAU Waitsia Gas Project Stage 2	91.25	300,000	3.28767	Waitsia Gas Project Stage 2 Greenhouse Gas Management Plan
BHP Macedon Gas Development	76.65	115,000	1.50033[b]	Macedon Gas Development - Report and recommendations of the EPA
AGIG Tubridgi Gas Field Development	25.55	11,724	0.46000[c]	Tubridgi Gas Field Development – Inquiry of the EPA
Apache Energy Ltd Devil Creek Gas Development Project	80.30	125,000	1.55666	Apache Energy Ltd Devil Creek Gas Development Project – Report and recommendations of the EPA

a) Year 1 and 2 are estimated to be 105,951 tCO_2-e per annum as for the initial setup.
b) Estimated based on average annual GHG emissions of 115,000 tCO_2-e, gas production rate of 200 million standard cubic feet per day and operations 365 days per year.
c) Estimated based on its Scope 1 emissions reported in FY2022 NGER report, proposed annual gas production rate of 70 TJ per day and operations 365 days per year.

4.3 GHG Monitoring and Reporting

4.3.1 National Greenhouse and Energy Reporting (NGER)

The NGER scheme is a Commonwealth initiative, introduced in 2007, to provide data and accounting in relation to GHG emissions and energy consumption and production.

Under the NGER scheme, corporations that exceed the corporate or facility thresholds need to report annually to the CER (Table 21).

Table 21 Key NGER Thresholds

Level	GHG Emissions	Energy Consumed / Produced
Facility	25,000 tCO_2-e	100,000 GJ
Corporate	50,000 tCO_2-e	200,000 GJ

The controlling corporation (as defined in the *NGER Act)* of this project is likely to be MinRes. It is expected that this company will have to include the GHG emissions, energy consumption and energy production from this project in their NGER report.

4.3.2 Safeguard Mechanism

Starting on 1 July 2016, the Australian Government introduced a Safeguard Mechanism under section 22XS of the NGER Act. As a consequence, responsible emitters controlling facilities which emit 100,000 tCO_2-e (Default Baseline) or more of scope 1 GHG emissions will be required to meet the safeguard requirements, including keeping the facility's net emissions at or below a set baseline emissions level.

Section 22XB of the NGER Act requires that the responsible emitter report annual covered emissions to enable a comparison against a baseline determined by the CER.

In the event of the reported annual emissions being below the baseline, the Safeguard facility would become eligible for Safeguard Mechanism Credits (SMC) under the new reform which could be used for compliance purposes. However, should the emissions be above the baseline; the responsible emitter will be required to 'make good' the excess emissions by surrendering carbon credit units or alternatively be liable to a substantial penalty.

The projected annual Scope 1 GHG emissions for the Project are estimated to be 78,198 tCO_2-e. According to the NGER Act and Safeguard Mechanism, the activities of the Project falling under the overall control of MinRes must be included and reported as the emissions of the Project, designating it as an NGER facility. These activities may encompass construction and exploration drilling (though not part of this referral), if they are under the overall control of MinRes and are included within the facility reporting boundaries. In the event that the cumulative emissions exceed 100,000 tCO_2-e, the Project may become subject to obligations as a responsible emitter under the Safeguard Mechanism.

4.4 Adaptive Management and Management Plan Review

In line with the concept of adaptive management, it is recommended that mitigation and management strategies be reviewed and updated (where appropriate) in response to triggers such as:

- Introduction of a new process or activity that has the potential to alter existing GHG emissions,
- Changes to relevant State or Commonwealth legislation, policy or guidelines,
- Introduction of new GHG reduction technologies,
- Technical review of implemented emissions monitoring,
- Relevant audit findings,
- EPA and decision-making authorities' comments during the Environmental approval process, or
- Update or implementation of an operating licence issued under Part V of the EP Act.

5 Glossary

Terms	Definitions
AGRU	Acid Gas Removal Unit
CH_4	Methane
CO_2	Carbon Dioxide
CO_2-e	Carbon dioxide equivalence, the amount of the gas multiplied by a value specified in the regulations in relation to that kind of greenhouse gas.
Determination	The NGER Determination 2008
Downstream emissions	Indirect GHG emissions related to sold goods and services
EPA	Western Australian Environmental Protection Authority
EP Act	*Environmental Protection Act 1986*
Facility	Is a single enterprise that undertakes an activity, or a series of activities that involve greenhouse gas emissions, the production of energy or the consumption of energy.
GHG	All greenhouse gases mentioned in the NGER Act
MEG	Monoethylene glycol
ML	Million Litre
N_2O	Nitrous oxide
Non-transport	Includes purposes for which fuel is combusted that do not involve transport energy purposes, see Sections 2.20, and 2.42 of the Determination.
Safeguard Mechanism Rules	National Greenhouse and Energy Reporting (Safeguard Mechanism) Rule 2015
Scope 1	Emission of greenhouse gas, in relation to a facility, means the release of greenhouse gas into the atmosphere as a direct result of an activity or series of activities (including ancillary activities) that constitute the facility.
Scope 2	Emission of greenhouse gas, in relation to a facility, means the release of greenhouse gas into the atmosphere as a direct result of one or more activities that generate electricity, heating, cooling or steam that is consumed by the facility but that do not form part of the facility.
Scope 3	Indirect emissions of greenhouse gas, that are not included in scope 2, that occur in the value chain of the reporting company.
STP	Standard Temperature and Pressure
Transport	Includes purposes for which fuel is combusted for transport by vehicles registered for road use, rail transport, marine navigation, and air transport, see Sections 2.20, and 2.42 of the Determination
Upstream emissions	Indirect GHG emissions related to purchased or acquired goods and services

Appendix A Scope 3 Emission Categories and Relevancy

Category	Description
1. Purchased goods and services	All emissions from the production of products and services purchased or acquired by the reporting company in the reporting period. *Example: The emissions associated with the extraction, production and transportation (between suppliers) of copper that is purchased by the reporting company to create bronze.*
2. Capital goods	All upstream emissions from the production of capital goods purchased by the company in the reporting period. *Example: Emissions associated with the production of excavators used by the reporting company.*
3. Fuel- and energy-related activities (Not included in scope 1 or scope 2)	All emissions related to the production (extraction, processing, transport etc.) of fuel and energy purchased by the reporting company, that are not included in the company's scope 1 and scope 2 emissions. *Example: The emissions from extracting crude oil, processing it to form diesel and transporting it to a site run by the reporting company.*
4. Upstream transportation and distribution	All emissions resulting from the transportation and distribution of purchased products, between a company's tier 1 suppliers and its own operations, in vehicles not owned by the reporting company, as well as any third-party transportation and distribution services purchased by the reporting company between a company's own facilities. *Example: Emissions from transportation of purchased copper between the supplier and the reporting company's bronze manufactoring facility.*
5. Waste generated in operations	All emissions from third-party treatment and disposal of waste that is generated by the company in the reporting period. *Example: Waste sent from the reporting company's site facilities for recycling, disposal at landfills, incineration, composting, etc.*
6. Business travel	All emissions from the transportation of employees for business-related activities in vehicles owned or operated by third-parties. *Example: Flights to business conferences and meeting suppliers.*
7. Employee commuting	All emissions from the transportation of employees between their homes and worksites. *Examples: FIFO and DIDO to site.*
8. Upstream leased assets	All emissions from the operation of leased assets that are not included in the company's scope 1 and 2 emissions inventory. *Example: Emissions from leased cars, offices and buildings.*
9. Downstream transportation and distribution	All emissions from third-party transport and distribution of the company's sold products in the reporting period. *Example: Emissions from third-party marine transportation of iron ore sold by the reporting company to be processed by another company.*
10. Processing of sold products	All emissions from processing of sold intermediate products by third-parties, subsequent to the sale of the product by the reporting company. *Example: Emissions from processing of iron ore sold by the reporting company to create steel.*

Category	Description
11. Use of sold products	All emissions from the use of goods and services sold by the reporting company in the reporting period. *Example: Emissions from the combustion of diesel, produced by the reporting company, as fuel for cars.*
12. End-of-life treatment of sold products	All emissions from the waste disposal or treatment of products sold by the company in the reporting period, at the end of their life. *Example: Emissions from recycling of metal cans sold by the reporting company.*
13. Downstream leased assets	All emissions from the operation of assets owned by the company and leased to third-parties in the reporting period, if they are not included in the company's scope 1 and scope 2 emissions. *Example: Emissions from electricity used in offices/buildings leased by the reporting company to other operations.*
14. Franchises	All emissions from the operation of franchises, by franchisees, not included in the franchisor's scope 1 and scope 2 emissions. *Example: Emissions from operations associated with a company's trademark.*
15. Investments	All emissions associated with operating the reporting company's investments in the reporting period. *Example: Emissions associated with a mine a company has a financial investment in but not operational control.*

Criteria	Description
Size	They contribute significantly to the company's total anticipated scope 3 emissions.
Influence	There are potential emissions reductions that could be undertaken or influenced by the company.
Risk	They contribute to the company's risk exposure (e.g., climate change related risks such as financial, regulatory, supply chain, product and customer, litigation, and reputational risks).
Stakeholders	They are deemed critical by key stakeholders (e.g., customers, suppliers, investors, or civil society).
Outsourcing	They are outsourced activities previously performed in-house or activities outsourced by the reporting company that are typically performed in-house by other companies in the reporting company's sector.
Sector guidance	They have been identified as significant by sector-specific guidance.
Other	They meet any additional criteria for determining relevance developed by the company or industry sector.

Source: GHG Protocol (2011)

Appendix B Scope 1 & 3 GHG Summary

ITEM N°	ITEM	VALUE	UNITS	NOTE	COMMENT
SUMMARY					
1 -	Scope 1 Emissions Summary - Operations				
1a	Scope 1	78,198	tCO2-e/year		= 3i
1b	Scope 2	-	tCO2-e/year		No electricity expected to be purchased for the project
1c	Total of Scope 1 & Scope 2	78,198	tCO2-e/year		= 1a + 1b
1d	Energy production	195,071,500	GJ/ year		= 5e
1e	Energy consumption	14,342,814	GJ/ year		= 7f
1f	Fugitive Emissions	2,553	tCO2-e/year		= SUM(3a : 3e)
1g	Flaring	3,048	tCO2-e/year		= 3f
1h	Venting	22,764	tCO2-e/year		= 3g
1i	Gas Combustion (Electricity)	49,720	tCO2-e/year		= 29e
1j	Diesel Combustion (Electricity)	113	tCO2-e/year		= 30e
1k	Diesel Combustion (Stationary)	-	tCO2-e/year		
	The below is the intensity of the whole project. Emission intensities that meet the Safeguard Rule are required to be further assessed				
1l	Emissions intensity - Natural Gas Produced	0.881100	tCO_2-e/GJ gas produce		= 1a ÷ (10d x 1,000)

ITEM N°	ITEM	VALUE	UNITS	NOTE	COMMENT
2 -	Scope 1 Emissions Summary - Construction - Total				
2a	Scope 1	11,257	tCO2-e		= 4d
2b	Scope 2	-	tCO2-e		No electricity expected to be purchased for the project
2c	Total of Scope 1 & Scope 2	11,257	tCO2-e		= 2a + 2b
2d	Energy production	-	GJ		N/A
2e	Energy consumption	134,606	GJ		= 9c
2f	Fugitive Emissions	-	tCO2-e		N/A
2g	Flaring	-	tCO2-e		N/A
2h	Venting	-	tCO2-e		N/A
2i	Gas Combustion (Electricity)	-	tCO2-e		N/A
2j	Diesel Combustion (Electricity)	-	tCO2-e		N/A
2k	Diesel Combustion (Stationary)	9,449	tCO2-e		= 4a + 4b
2l	Land Clearing (Lost carbon sink)	1,808	tCO2-e		= 4c

4 -	Scope 3 Emissions Summary - Operations			
4a	Scope 3	5,172,054	tCO2-e/year	= 53e
4b	Category 3 - Fuel and Energy-related Activities	28	tCO2-e/year	= 53a
4c	Category 9 - Downstream Transportation and Distribution	397,512	tCO2-e/year	= 53b
4d	Category 10: Processing of Sold Product	34,472	tCO2-e/year	= 53c
4e	Category 11: Use of Sold Product	4,740,043	tCO2-e/year	= 53d

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