BELISAMA CONVENTIONAL GAS PROJECT

GREENHOUSE GAS ASSESSMENT TECHNICAL REPORT

Version 1.1

Prepare by **Greenbase Pty Ltd**

On behalf of **Hancock Energy (PBN) Pty Ltd**

Prepared December 2025

Project Task ID: 55281

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Rounding of Amounts

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

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Table 1 Document History

Ver.	Date Completed	Details	Name	Role
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	05/12/2025	Reviewed and provided feedback	Hancock Energy (H. Studham, A.Trolove, Z.Thomson)	Reviewer
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Summary

Hancock Energy (PBN) Pty Ltd (Hancock Energy) is the proponent for Belisama Conventional Gas Project (the Project), located in the mid-west region of Western Australia. the Project is designed to produce up to 210 TJ per day of sales quality gas, with the condensate byproduct being stored onsite prior to being transported offsite for export.

The proposed project includes a Central Processing Facility (CPF), the extension of the Lockyer Central Flowline to the new CPF location (29°19'38"S 115°16'20"E) owned in freehold by Hancock Energy, the inclusion of additional Lockyer wells into the gathering system, and the connection of the West Erregulla Upstream Gathering System to the new CPF. Greenhouse gas emissions associated with the West Erregulla Upstream Gas Gathering System have been subject to a separate greenhouse gas assessment by the operator of that field.

The proposed project includes gas from upstream wells, an infield gathering system comprising underground flowlines and collection hubs, and a central processing facility (CPF). The CPF will include supporting infrastructure such as power generation, warehousing and workshops, switch room facilities, a sedimentation pond, evaporation ponds, and accommodations. In addition, the project will involve an underground gas export pipeline connecting the CPF to the Dampier Bunbury Gas Pipeline (DBNGP), as well as a condensate stabilisation unit with associated storage and offloading facilities.

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, 2024). The estimated GHG emissions (Scope 1, 2 and 3) from the Project have been estimated in this assessment.

Based on the assessment, the estimated GHG emissions during the operational phase of the Project are projected to be 85,917 tCO_2-e annually. The GHG emissions anticipated with the construction activities have been estimated to be 11,625 tCO_2-e in total.

Scope 3 emissions were examined in this assessment with key emission sources identified for operational phase as 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 4,275,616 tCO_2-e annually.

Overall, the average GHG emission intensity for the Project was estimated to be 1.1525 tCO_2-e/terajoule (TJ) of pipeline natural gas produced.

1 Introduction

1.1 Background

Hancock Energy (PBN) Pty Ltd (Hancock Energy) is proposing to develop Belisama Conventional Gas Project (the Project), located in the mid-west region of Western Australia. the Project is designed to produce up to 210 TJ per day of sales quality gas, with the condensate byproduct will be stored onsite prior to being transported offsite for export.

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	Belisama Conventional Gas Project (the Project)
Proponent Name	Hancock Energy (PBN) Pty Ltd (Hancock Energy)
Proposed commencement date of the Project	2026 – Construction 2029 – Gas Production

1.2 Belisama Conventional Gas Project

The Belisama Conventional Gas Project (the Project) is located in the mid-west region of Western Australia. The Project is designed to produce up to 210 TJ per day of sales quality gas, with the condensate byproduct will be stored onsite prior to being transported offsite for export.

The proposed project includes a Central Processing Facility (CPF), the extension of the Lockyer Central Flowline to the new CPF location, the inclusion of additional Lockyer wells into the gathering system, and the connection of the West Erregulla Upstream Gathering System to the new CPF.

The Project will consist of:

- Production wells,
- An infield gathering system comprising underground flowlines and collection hubs,
- A CPF, including supporting infrastructure such as power generation, warehousing and workshops, switch room facilities, a sedimentation pond, evaporation ponds, and accommodations.
- An underground gas export pipeline connecting the CPF to the Dampier Bunbury Gas Pipeline (DBNGP), and
- Condensate stabilisation, storage and offloading system to support road transport of liquid product.

Figure 1 Project CPF (Indicative)

1.3 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 these commitments, each state and territory has set their own net-zero target. Western Australia is committed to achieving net-zero emissions by 2050 as outlined in the Western Australian Climate Policy (Government of Western Australia, 2020).The WA State Government has also released he State's first Climate Adaptation Strategy in July 2023, to improve the climate-resilience of the communities, environment and economy.

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 GHG emissions per year) are required to demonstrate their ability to contribute to Western Australia's net-zero target. The EPA has published the Environmental Greenhouse Gas Emissions Guideline in 2020 to further inform the EIA process, with a recent revision published in November 2024.

1.4 Applicable Environmental Factors

According to the most recent *Greenhouse Gas Emissions Environmental Factor Guideline* (EPA, 2024), GHG emissions from a proposal will be considered where they are reasonably likely to exceed:

- 100,000 tonnes CO_2-e of Scope 1 emissions in any year; or
- 100,000 tonnes CO_2-e of Scope 2 emissions in any year.

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), and
- Perfluorocarbons (PFCs).

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

2 GHG Inventory

2.1 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 and storage prior to transportation.
- Other supporting activities including well clean-up and construction of infrastructure.

2.2 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 details below.

2.2.1 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,
- Fuel gas consumption by the power station (electricity purposes),
- Fugitive emissions from extraction, gathering, processing and transmission of natural gas and handling of produced water, and
- Diesel consumption by the support equipment and other vehicles for construction (non-transport purposes).

2.2.2 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.

2.2.3 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 B.

Table 3 Scope 3 GHG Emissions Categories (Greenhouse Gas 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. However, no secondary fuel is expected to be used during the operational phase of the Project	Excluded
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

2.3 Limitations and Exclusions

The following emissions 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),
- Wastewater treatment plant (WWTP), and
- Land clearing (lost carbon sink) and the diesel consumption by the equipment and other vehicles for the activities.
  - Works will be undertaken on previously cleared land, with minimal additional clearing required, and thus associated emissions assumed to be minimum.

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 over the project may result in adjustments to emission estimates.

2.4 GHG Emissions Methodology

2.4.1 Scope 1 GHG Emissions

Scope 1 GHG estimates from all sources of the Project have been prepared using methods and emissions factors from the most recent *National Greenhouse and Energy Reporting (Measurement) Determination 2008 (*NGER Determination), as applicable to 2025-26 financial year (FY2026) reporting.

2.4.1.1 Fuel Consumption

For emission calculations, fuel use is split into 3 categories, namely transport (for road-registered vehicles), non-transport and electricity, based on the associated activity.

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

2.4.1.2 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, as outlined in Section 3.73B of 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}

2.4.1.3 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. Fugitive emissions from natural gas gathering and boosting have been prepared using Method 2, as outlined in Section 3.73LA and 3.73LB of the NGER Determination. The emission factors used are shown in Table 6 and Table 7.

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

Equipment Type	Emissions Factor (tonnes CO_2-e/ equipment-hour)	
	CH_4	CO_2
Metering installation and associated piping	9.86×10^{-4}	2.45×10^{-6}
Dehydrators	2.00×10^{-3}	4.96×10^{-6}

Table 7 Fugitive Emission Factors from Natural Gas Gathering & Boosting Pipelines 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}

2.4.1.4 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, as outlined in Section 3.73NB of the NGER Determination. The methane emission factor used, for an average pressure of a water stream below 345 kilopascals and average salinity of 30,000 mg/L, is 0.7439 tonnes CO_2-e per ML water.

2.4.1.5 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, as outlined in Section 3.73R of the NGER Determination. The emission factors used are shown in Table 8.

Table 8 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}

2.4.1.6 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.

2.4.1.7 Gas Flaring

Scope 1 GHG estimates from gas flaring have been prepared using Method 1, as outlined in Section 3.86 of the NGER Determination. The emission factors applied to flaring conducted during operations are shown in Table 9. 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 9 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	2.69	0.56	0.021	3.271

2.4.1.8 Gas Venting

Scope 1 GHG estimates from gas venting from the MEG Regeneration system have been prepared using Method 1 from the NGER Determination. The molar weight and molar volume conversion applied to calculations are shown in Table 10.

Table 10 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

2.4.2 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 (2025),
- UK Conversion Factors (2025), and
- Various scientific studies.

2.4.2.1 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 Kwinana Port 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 (2025) 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

2.4.2.2 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.

2.4.2.3 Category 11 – Use of Sold Product

Scope 3 emissions from category 11 of this Project include:

- Emissions from combustion of sold natural gas.

  It has assumed that all the sold gas will be combusted. 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

2.5 GHG Emissions Estimates

GHG emissions (Scope 1 and 3) have been estimated for the Project's activities when it is in operations. 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 **Error! Reference source not found.**.

Table 13 Key Project Inputs

Input	Value
Total Product Produced	Raw hydrocarbon fluid extracted: 229 MMSCFD Natural gas produced: 74.55 PJ/year (210 TJ/day with 125 TJ/day from Lockyer Gas and 85 TJ/day from West Erregulla Gas) Condensate produced: 5.7 Sm^3/hour
Operating days per year	355 days
Total Gas Flared	260,606 Sm^3/year (734 Sm^3/day)
Total Gas Vented	MEG Regeneration: 16,782 Sm^3/year Reservoir CO_2: 31,730 tCO_2-e /year
Total Gas Consumption	Gas power generation: 71,070 Sm^3/day
Total Diesel Consumption	Diesel for construction: 4,290,120 Litres for 22 months
Gas composition	Lockyer Gas - CH_4 mol%: 87.84 %, CO_2 mol%: 3.60 % West Erregulla Gas- CH_4 mol%: 92.08 %, CO_2 mol%: 5.89 %
Fugitive emissions inputs	
Wellheads	7 wellheads, operating 8,350 hours per year
Gathering & boosting stations	2 metering installation and associated piping and 1 dehydrators, all operating 8,350 per year
- **Gathering system pipelines**	44km of protected steel pipe
- **Produced water**	Produced water produced: 1,200 Bp/day Salinity: 30,000 mg/L Pressure: <345 kPa
- **Natural gas processing**	2 Inlet compressors, 2 recycle compressors and 2 export compressors, with only one of the two parallel compressors operational at any time, all operating 8,350 hours per year
- **Natural gas transmission pipeline**	19km

2.5.1 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 85,917 tCO_2-e per year for the operational phase, and total emissions of 11,625 tCO_2-e from construction activities.

A summary of total scope 1 GHG emissions breakdown by source for the Project is outlined in Table 14 and Figure 2.

Table 14 Estimated Total Scope 1 Emissions for the Project

Phase	Category	Total Emissions (t CO2-e)
Construction	Diesel Combustion – Construction	11,625
	Total	**11,625**
Phase	**Category**	**Annual Emissions (t CO2-e/year)**
Operational	Fugitive Emissions from Onshore Natural Gas Production	34
	Fugitive Emissions from Natural Gas Gathering & Boosting	93
	Fugitive Emissions from Produced Water	54
	Fugitive Emissions from Natural Gas Processing	1,986
	Fugitive Emissions from Natural Gas Transmission	221
	Emissions from Flaring - Gas Treatment Processed	675
	Emissions from Venting (vented gas + reservoir CO_2 removed)	31,761
	Emissions from Exhaust Emissions	51,094
	Total	**85,917**

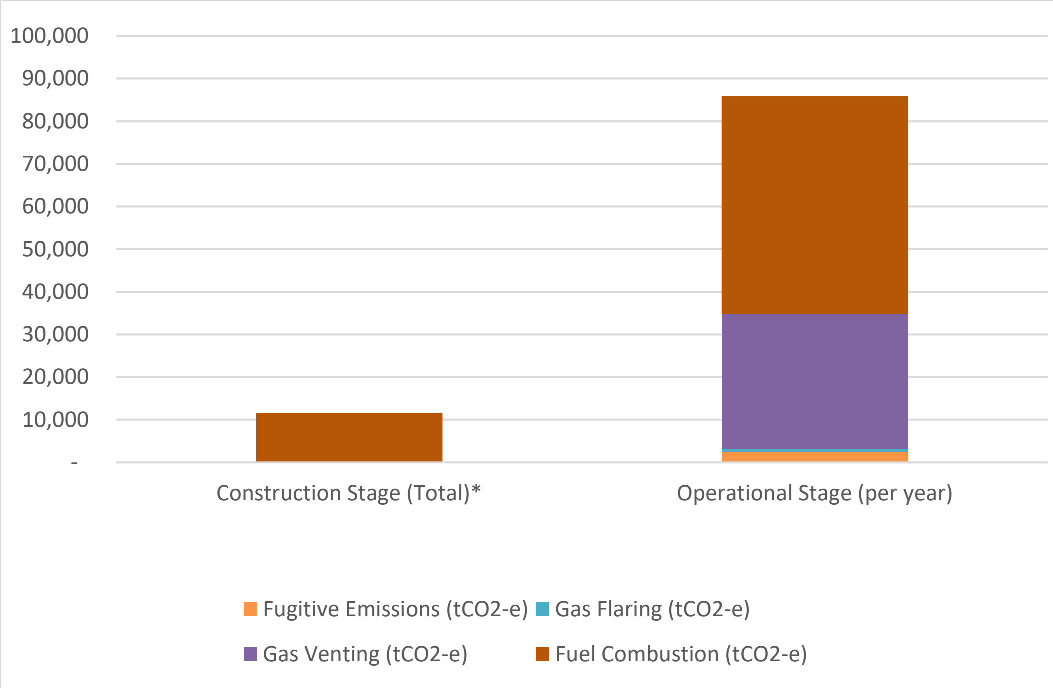
2.5.1.1 Construction Phase

Diesel combustion is considered the only major source of emissions during the construction phase, with total Scope 1 emissions estimated to be 11,625 tCO_2-e over the 22-month construction period.

2.5.1.2 Operational Phase

From the inputs detailed in Table 13 and the methodology described in section 2.4, the Project is estimated to generate approximately 2,388 tCO_2-e per year of fugitive emissions, 675 tCO_2-e per year of Scope 1 GHG emissions from gas flaring, 31,761 tCO_2-e per year of Scope 1 GHG emissions from gas venting, and 51,094 tCO_2-e per year from fuel gas combustion from power generation.

The reservoir CO_2 that will be removed has been included in the total vented gas and was estimated based on the design operating conditions.



*Total estimated emissions for the construction stage. The construction will be conducted for 22 months.

Figure 2 Breakdown of Scope 1 Emissions by Source for the Project

2.5.2 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 2.4.

It is estimated that the Project will create 4,275,616 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 15.

Table 15 Estimated Scope 3 Emissions for the Project

Category	Annual Emissions (tCO_2-e/ year)
Category 9 Downstream Transportation and Distribution	330,993
Category 10 Processing of Sold Products	17,655
Category 11 Use of Sold Products	3,926,967
Total	**4,275,616**

3 Benchmark Assessment

3.1 Contribution of the Project GHG emissions

Total estimated emissions of Australia from Department of Climate Change, Energy, the Environment and Water for the year to March 2025 was 440.2 million tonnes CO_2-e (DCCEEW, 2025). The Clean Energy Regulator (CER) published the annual NGER data for FY2023-24 in February 2025. For the FY2023-24, registered corporations reported a total of 303 million tCO_2-e of Scope 1 GHG emissions and 74 million tCO_2-e of Scope 2 GHG emissions (CER, 2025). There were 21% of Scope 1 GHG emissions contributed from Western Australia (CER, 2025).

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 16.

Table 16 Estimated Impact of the Project Scope 1 GHG Emissions

Location	FY2024 Scope 1 GHG Emissions (Million tCO_2-e)	% Contribution from the Project
Western Australia[a]	66	0.130%
Australia[b]	440	0.020%

a) Source from Clean Energy Regulator (CER, 2025). 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: March 2025 (DCCEEW, 2025).

3.2 Emission Intensity

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

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

Emission intensity estimated for the Project is 1.1525 tCO_2-e/tonnes gas produced.

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

- Onshore,
- Conventional natural gas extraction, and
- Producing the same products.

The GHG emission intensities benchmarking comparison for the Project is outlined in Table 17.

Table 17 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
Hancock Energy Belisama Conventional Gas Project	74.55	85,917	1.1525	From this assessment
Other projects				
AGIO West Erregulla Processing Plant and Pipeline	31.76	96,319[a]	3.0332	West Erregulla Processing Plant and Pipeline Greenhouse Gas Management Plan
MEPAU Waitsia Gas Project Stage 2	91.25	300,000	3.2877	Waitsia Gas Project Stage 2 Greenhouse Gas Management Plan
BHP Macedon Gas Development	76.65	115,000	1.5003[b]	Macedon Gas Development - Report and recommendations of the EPA
AGIT Tubridgi Gas Field Development	25.55	11,724	0.4600[c]	Tubridgi Gas Field Development – Inquiry of the EPA
Apache Energy Ltd Devil Creek Gas Development Project	80.30	125,000	1.5567	Apache Energy Ltd Devil Creek Gas Development Project – Report and recommendations of the EPA
Strike South Erregulla Conventional Gas Development	29.20	63,040	2.16	South Erregulla Conventional Gas Development – Referral Document for EPA Part IV Section 38
Imperial Oil Carpentaria Pilot Project	9	36,078	4.01	Carpentaria Pilot Project Environmental Management Plan EP187 IMP 5-3

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 GHG Monitoring and Reporting

4.1.1 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 18).

It is expected that the corporate will have to include the GHG emissions, energy consumption and energy production from the Project in their NGER report.

Table 18 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

4.1.2 Safeguard Mechanism

Starting on 1 July 2016, the Australian Government introduced a Safeguard Mechanism under section 22XS of the NGER Act. Responsible emitters for facilities that emit 100,000 tCO_2-e or more of Scope 1 GHG emissions are required to meet the Safeguard requirements, including keeping the facility's Scope 1 emissions at or below a set baseline. Should the emissions exceed the baseline; the responsible emitter will be required to 'make good' the excess emissions by surrendering Australian Carbon Credit Units (ACCUs) or Safeguard Mechanism Credits (SMCs) or be liable to a substantial penalty.

The Safeguard Mechanism reforms introduced in 2023 apply a decline rate to facilities' baselines so that they are reduced on a trajectory consistent with achieving Australia's emissions reduction targets of 43% below 2005 levels by 2030 and net zero by 2050. The decline rate will be set at 4.9% each year to 2030. Post-2030 decline rates will be set in predictable five-year blocks, after updates to Australia's Nationally Determined Contribution (NDC) under the Paris Agreement.

With forecast annual Scope 1 GHG emissions of 85,917 tCO_2-e, the Project is not likely to exceed the default Safeguard baseline of 100,000 tCO_2-e when it is in operation.

Appendix A Glossary

Terms	Definitions
CER	Clean Energy Regulator
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
HFCs	Hydro fluorocarbons
MEG	Monoethylene glycol
MS	Ministerial Statement
N_2O	Nitrous Oxide
NGER	National Greenhouse and Energy Reporting
NGER Act	The National Greenhouse and Energy Reporting Act 2007 as it applies to the current reporting year
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.
PFCs	Perfluorocarbons
Regulations	The NGER Regulations 2008
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.
SF_6	Sulphur Hexafluoride – a gas used in switchgear and circuit breakers for insulation.
t CO_2-e	Tonnes of carbon dioxide equivalent
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
UNFCCC	United Nations Framework Convention on Climate Change
Upstream emissions	Indirect GHG emissions related to purchased or acquired goods and services

Appendix B 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.*

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 C Scope 1 & 3 GHG Summary

4 -	Scope 1 Emissions Summary - Operations			
4a	Scope 1	85,917	tCO2-e/year	= 40i
4b	Scope 2	-	tCO2-e/year	No electricity expected to be purchased for the project
4c	Total of Scope 1 & Scope 2	85,917	tCO2-e/year	= 4a + 4b
4d	Fugitive Emissions	2,388	tCO2-e/year	= SUM(40a : 40e)
4e	Flaring	675	tCO2-e/year	= 40f
4f	Venting	31,761	tCO2-e/year	= 40g
4g	Gas Combustion (Electricity)	51,094	tCO2-e/year	= 40h
	The below is the intensity of the whole project. Emission intensities that meet the Safeguard Rule are required to be further assessed			
4h	Emissions intensity - Natural Gas Produced	1.152479	tCO_2-e/TJ gas produce	= 4a ÷ (43g x 1,000)
5 -	Scope 1 Emissions Summary - Construction - Total			
5a	Scope 1	11,625	tCO2-e	= 41a
5b	Scope 2	-	tCO2-e	No electricity expected to be purchased for the project
5c	Total of Scope 1 & Scope 2	11,625	tCO2-e	= 5a + 5b
5d	Diesel Combustion (Stationary)	11,625	tCO2-e	= 41a + 41b
5e	Land Clearing (Lost carbon sink)		tCO2-e	Works will be undertaken on previously cleared land, with minimal additional clearing required. Associated emissions assumed to be minimum
6 -	Scope 3 Emissions Summary - Operations			
6a	Scope 3	4,275,616	tCO2-e/year	= 62e
6b	Category 3 - Fuel and Energy-related Activities	-	tCO2-e/year	= 62a
6c	Category 9 - Downstream Transportation and Distribution	330,993	tCO2-e/year	= 62b
6d	Category 10: Processing of Sold Product	17,655	tCO2-e/year	= 62c
6e	Category 11: Use of Sold Product	3,926,967	tCO2-e/year	= 62d

Appendix D References

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