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Hancock Energy (PBN) Pty Ltd

# Belisama Conventional Gas Project

## Independent Peer Review - Greenhouse Gas Estimate

EC262-0001 Revision 00 23 December 2025

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# Acronyms/Definitions

| Acronym | Definitions |
|---|---|
| AGRU | Acid Gas Removal Unit |
| bbl | Barrel of Oil |
| BTEX | Benzene, Toluene, Ethylbenzene, Xylene |
| $CH_4$ | Methane |
| CPF | Central Processing Facility |
| $CO_2$ | Carbon Dioxide |
| $CO_2$-e | Carbon Dioxide equivalent |
| DBNGP | Dampier to Bunbury Natural Gas Pipeline |
| DWER | Department of Water and Environmental Regulation (WA) |
| EP Act | *Environmental Protection Act 1986 (WA)* |
| EPA | Environmental Protection Authority (Western Australia) |
| GHG | Greenhouse Gas |
| GJ | Gigajoule |
| GWP | Global Warming Potential |
| Hancock Energy | Hancock Energy (PBN) Pty Ltd |
| $H_2S$ | Hydrogen Sulfide |
| kPa | Kilopascal |
| kWh | Kilowatt hour |
| L | Litre |
| MEG | Monoethylene Glycol |
| MMSCF | Million Standard Cubic Feet |
| MWh | Megawatt hour |
| NGER | National Greenhouse and Energy Reporting |
| PJ | Petajoule |
| PFW | Produced Formation Water (produced water) |
| $Sm^3$ | Standard cubic metre |
| t | tonne |
| TJ | Terajoule |

# Contents



# Tables

# 1. Executive Summary

This independent peer review of the Hancock Energy (PBN) Pty Ltd (Hancock Energy) Belisama Conventional Gas Project (the Project) greenhouse gas (GHG) emission have been completed and validates the technical basis for GHG quantification, calculation methodologies, and emissions management approach adopted by the Project.

### Scope 1 Emissions - Operations

The combined Scope 1 operational emissions have been calculated for two operating scenarios:

- Case 1 (N15B) Lockyer gas only at 210 TJ/day = 72,938 t$CO_2$-e/year
- Case 2 (N13B) Lockyer 125 TJ/day and West Erregulla 85 TJ/day = 85,917 t$CO_2$-e/year

Both scenarios remain below the 100,000 t$CO_2$-e/year Commonwealth Safeguard Mechanism threshold.

### Scope 2 Emissions

Scope 2 emissions are estimated at zero for both scenarios, reflecting the Project design assumption that all electrical power will be generated on-site via reciprocating gas engines with no external power supply required.

### Scope 3 Emissions

The GHG assessment identified three material Scope 3 categories (Categories 9, 10, and 11), with Categories 10 and 11 representing over 92% of total Scope 3 emissions. The methodologies for calculating Categories 10 and 11 have been reviewed and validated against the GHG Protocol Corporate Value Chain Standard.

### Technical Validation Points

1. Calculation Verification: The GHG emissions calculations apply NGER methodologies. Material emission source calculations have been verified against information and clarifications received from Hancock Energy.
2. Emission Technologies: The emission control technologies and design measures align with local and national industry best practice, including reciprocating engines for power generation, selective amine technology for $CO_2$ removal and flare gas recovery systems.
3. Gas Composition Impact: The lower $CO_2$ content and high energy density of Lockyer gas are correctly reflected in reduced Acid Gas Removal Unit (AGRU) extraction requirements, delivering emissions benefits compared to equivalent Perth Basin projects.
4. Co-Processing Benefits: The co-processing of West Erregulla gas with Lockyer gas delivers material emissions benefits. The Project's Case 2 emissions (85,917 t$CO_2$-e/year) are lower than those of the standalone West Erregulla facility (96,319 t$CO_2$-e/year), despite processing approximately 2.4 times the throughput, demonstrating engineering optimisation through blended gas processing.
5. Emissions Intensity Benchmarking: The Project's emission intensities (Case 1: 0.9784 t$CO_2$-e/TJ; Case 2: 1.1525 t$CO_2$-e/TJ) compare favourably to similar Perth Basin projects including West Erregulla (3.03 t$CO_2$-e/TJ) and Waitsia Stage 2 (3.29 t$CO_2$-e/TJ).

### Conclusion

Based on the information provided, the GHG emissions calculations for the Project have been independently reviewed and found to meet industry standards for calculation methodologies and best practices in technology selection and operational design.

# 2. Introduction

Hancock Energy commissioned this independent peer review to validate the GHG emissions calculations for the Belisama Conventional Gas Project (the Project). The review applies a systematic approach to verify calculation methodologies, input assumptions, and emission factors against applicable standards and industry practices, with particular focus on understanding how gas composition characteristics influence emissions outcomes between the two proposed operating scenarios.

## 2.1 Scope of the Peer Review

The Project proposes to construct and operate a Gas Processing Facility with a capacity of up to 210 TJ/day and associated infrastructure in Western Australia's mid-west region.

The scope of this independent peer review encompasses:

- Assessment of the GHG emission calculation methodologies for consistency with relevant standards.
- Verification of assumptions and emission factors utilised in the calculations.
- Evaluation of design and operational best practice measures for GHG emissions reduction.
- Validation of emissions calculations for two distinct operating scenarios.
- Technical assessment of the gas quality characteristics and their impact on emissions outcomes.

## 2.2 Project Overview

The Project will develop conventional gas resources in the Mid-West region of Western Australia, gathering gas from surrounding fields, including the Lockyer gas field and potential future tie-ins such as West Erregulla gas field. It will process the gas at a new Central Processing Facility (CPF) designed for up to 210 TJ/day of sales gas. The CPF will treat the gas to pipeline specifications, route the product gas to the Dampier to Bunbury Natural Gas Pipeline (DBNGP), and store condensate on site for road transport. Additionally, it will incorporate emissions-reduction technologies such as mercury and $H_2S$ guard beds, a thermal oxidiser, and high-efficiency power generation to minimise GHG emissions.

## 2.3 Gas Specification Overview

### 2.3.1 Lockyer Gas Properties

Lockyer gas is characterised by a composition of primarily 87.8% methane, 3.6% carbon dioxide and 7.9% C2+ fraction. This composition delivers high energy content per unit volume, driven primarily by its elevated methane concentration. The gas contains a higher hydrocarbon condensate fraction, which provides additional heating value beyond the gaseous methane component, resulting in a higher overall energy density than in other Perth Basin fields.

### 2.3.2 West Erregulla Gas Properties

West Erregulla gas mainly contains 92.1% methane, 5.9% carbon dioxide and 1.7% C2+ fraction. Despite the higher methane content, its overall heating value is considerably lower than Lockyer gas because of the higher $CO_2$ level, which does not contribute to combustion energy. Processing West Erregulla gas requires additional acid gas removal to meet the DBNGP pipeline quality specifications for both heating value and maximum allowed $CO_2$ content.

### 2.3.3 Impact of Gas Composition on Gas Processing

From a thermodynamic perspective, Lockyer gas, which is richer in methane and hydrocarbon condensates, provides more usable energy per unit volume. This higher energy density allows the facility to meet DBNGP quality specifications (heating value and $CO_2$ content limits) with minimal processing effort. Conversely, West

Erregulla gas has a higher $CO_2$ content (5.9%), which does not contribute to combustion energy and necessitates more extensive acid gas removal to meet pipeline standards.

## 2.4 Documentation Reviewed

The following documentation has been reviewed as part of this peer review:

- Greenbase Pty Ltd (Greenbase), Belisama Conventional Gas Project GHG Technical Report 2025 Project Case 1 FINAL
- Greenbase Pty Ltd (Greenbase), Belisama Conventional Gas Project GHG Technical Report 2025 Project Case 2 FINAL
- Greenbase Pty Ltd (Greenbase), Belisama Conventional Gas Project GHG Assessment – Final v1.0 2025 [Spreadsheet]
- Hancock Energy, Belisama Conventional Gas Project Development Approval Summary – Section 4.4 (Air Quality) and 4.5 (Greenhouse Gas Emissions) - BGP-0000-EN-REP-00001
- Hancock Energy, Belisama Conventional Gas Project Air Quality Assessment (Final, Rev B), MRP Technical Consulting Pty Ltd
- Hancock Energy, Belisama Conventional Gas Project Occupational Exposure Assessment (Final, Rev B), MRP Technical Consulting Pty Ltd
- Mineral Resources, Lockyer Conventional Gas Project Energy Technology Peer Review (GHD 2024)
- Australian Gas Infrastructure Group, West Erregulla GHG Environmental Management Plan, Rev 4

# 3. Scope 1 Emissions Analysis

This section validates the Scope 1 GHG emissions assessment for the Project, focusing on the methodology applied and the quantification of direct emissions from construction and operational sources including fuel combustion, flaring, venting, and fugitive emissions.

Construction-phase emissions were excluded from this technical review, as they represent a one-off activity and are not material to the Project's ongoing operational emissions profile.

## 3.1 Methodology Review

The Scope 1 emissions assessment was prepared by Greenbase Pty Ltd (Greenbase) on behalf of Hancock Energy and documented in two separate technical reports for Project Case 1 (Lockyer Only) and Project Case 2 (Co-processing Scenario). Both assessments apply methodologies and emission factors from the *National Greenhouse and Energy Reporting (Measurement) Determination 2008 (NGER Determination)*, specifically referencing FY2025-26 reporting requirements.

Each of the emissions sources and methodology applied and documented in Section 2.4 of the GHG technical reports and calculations was reviewed and validated against the *National Greenhouse and Energy Reporting (Measurement) Determination 2008 (NGER Determination).*

**Table 3.1 Emissions Quantification NGER Methods**

| Emissions Source | NGER Reference | Assessment Method |
|---|---|---|
| Fugitive: Production wellheads | Section 3.73B | Method 2 |
| Fugitive: Gas gathering & boosting stations | Section 3.73LA<br>Section 3.73LB | Method 2 |
| Fugitive: Natural gas processing | Section 3.73R | Method 2 |
| Fugitives: Natural gas transmission | Section 3.73KA, 3.73KB | Method 1 |
| Fugitives: Produced Water | Section 3.73NB | Method 2 |
| Fugitives: Venting | Section 3.88G | Method 1 |
| Flaring | Section 3.86 | Method 1 |
| Fuel combustion | Sections 2.20, 2.42 | Method 1 |

All methodologies applied are consistent with the *NGER Determination* and represent accepted industry practice for conventional gas projects.

## 3.2 Key Emission Sources

### 3.2.1 Case 1 (Lockyer Only)

Case 1 assessment evaluated operations processing 210 TJ/day of Lockyer gas only, with the following emissions profile as detailed in Table 3.2. Correspondence with Hancock confirmed that the modelling applied a conservative approach by using the worst-case year (highest expected emissions), providing an upper-bound emissions envelope. Single-reservoir $CO_2$ is not anticipated to change substantially over the operational timeframe.

**Table 3.2 Emissions Profile Case 1 (Lockyer Only)**

| Source | $tCO_2$-e/year | % of Total |
|---|---|---|
| Venting (AGRU discharge) | 22,441 | 30.8% |
| Gas combustion<br>(electricity generation) | 47,528 | 65.1% |
| Fugitive emissions | 2,345 | 3.2% |
| Flaring | 624 | 0.9% |
| Total | 72,938 | 100% |

The largest emission source is combustion of natural gas in the on-site reciprocating engine for power generation (65%).

The GHG assessment appropriately applied the following parameters:

- Gas energy content of 0.0393 GJ/$m^3$
- Stationary combustion emissions factor of 51.3 kg $CO_2$-e/GJ
- Gas consumption rate of 66,110 $Sm^3$/day operating 355 days/year
- Accounted for the specific gas composition of Lockyer gas ($CH_4$ 87.8%, $CO_2$ 3.6%)

The second-largest source is $CO_2$ venting from the Acid Gas Removal Unit (31%). This represents $CO_2$ extracted from the inlet gas to meet DBNGP pipeline quality specifications ($CO_2$ limit of 3.8 mol%). The GHG assessment appropriately applied the following parameters:

- 0.5 mol% $CO_2$ reduction is required for Lockyer gas (compared to approximately 3 mol% for West Erregulla standalone).
- NGER-compliant emissions factors for $CO_2$ venting.

### 3.2.2 Case 2 (Co-Processing Scenario)

Case 2 assessment evaluated operations processing 210 TJ/day combined throughput from Lockyer and West Erregulla gases, with the emissions profile detailed in Table 3.3. Co-processing West Erregulla gas (85 TJ/day) with Lockyer gas (125 TJ/day) produces a blended stream with intermediate $CO_2$ content, reducing the extraction burden compared to standalone West Erregulla processing. As per Case 1, correspondence with Hancock confirmed that the modelling employed a conservative approach by using the worst-case year, providing an upper-bound emissions envelope.

**Table 3.3 Emissions Profile Case 2 (Lockyer and West Erregulla)**

| Source | $tCO_2$-e/year | % of Total |
|---|---|---|
| Venting (AGRU discharge) | 31,761 | 37.0% |
| Gas combustion (electricity generation) | 51,094 | 59.5% |
| Fugitive emissions | 2,388 | 2.8% |
| Flaring | 675 | 0.8% |
| Total | 85,917 | 100% |

The increase in Scope 1 emissions from Case 1 to Case 2 (+12,979 $tCO_2$-e/year or 17.8%) is attributable primarily to:

1. Venting increase (+9,320 $tCO_2$-e): Processing an additional 85 TJ/day of West Erregulla gas, which has a higher $CO_2$ content, requires greater $CO_2$ extraction. However, the blending effect substantially reduces the $CO_2$ extraction rate compared to West Erregulla standalone processing (see Section 8).
2. Power generation increase (+3,566 $tCO_2$-e): Increase in power generation emissions due to the blended gas from West Erregulla having a higher $CO_2$ content (5.9% vs 3.6% in Lockyer gas), requiring approximately 7.5% more gas volume to generate the same electrical output.
3. Fugitive and flaring increases: Fugitive emissions are slightly higher, primarily due to increased volumes unprocessed gas throughput with blended gas containing more methane-rich West Erregulla gas (89.56% $CH_4$ vs. 87.84% $CH_4$), which increases fugitive methane leaks from wellheads, gathering/boosting equipment, processing compressors, and transmission pipelines.

## 3.3 Calculation Verification

This verification focused on the Greenbase GHG assessments for both Case 1 (Lockyer gas only at 210 TJ/day) and Case 2 (blended gas: 125 TJ/day Lockyer and 85 TJ/day West Erregulla). Material emission sources, including gas combustion for power generation, fugitive emissions from natural gas processing and venting from acid gas removal, were subject to validation. A representative sample of minor emission sources (fugitive emissions from venting) was also examined to verify methodological consistency.

All calculations were verified against clarifications provided by both Hancock Energy and Greenbase regarding methodologies used and assumptions.

Based on information and clarifications received from Hancock Energy and Greenbase, all calculations have been verified as consistent with NGER-compliant methodologies and industry best practices.

# 4. Scope 2 Emissions Analysis

Scope 2 emissions associated with purchased electricity are estimated at zero for both operating scenarios. This reflects the Project design assumption that all electrical power will be generated on-site via a reciprocating gas engine powered by produced natural gas, with no requirement for external power supply.

This is an appropriate and conservative assumption for the design phase analysis. Should the Project design evolve to include any purchased electricity, Scope 2 emissions would need to be calculated and the assessment updated accordingly.

# 5. Scope 3 Emissions Analysis

The Greenbase GHG Technical Reports for both Case 1 and Case 2 identify three material categories quantified in accordance with the GHG Protocol Corporate Value Chain (Scope 3) Accounting and Reporting Standard (2011):

- Category 9 (Downstream Transportation and Distribution),
- Category 10 (Processing of Sold Products), and
- Category 11 (Use of Sold Products).

This review focused on Categories 10 and 11, which account for over 90% of total Scope 3 emissions across both cases.

## 5.1 Scope 3 Calculation Methodology

The Greenbase GHG Technical Reports apply the GHG Protocol calculation method, utilising emission factors and activity data as outlined in Section 2.4.2 of both technical reports. The methodology has been verified as consistent with established Scope 3 quantification practices. All other Scope 3 categories (1-8, 12-15) were systematically assessed and appropriately excluded as either not material, not applicable, or not directly influenced by Project operations, as documented in Table 3 and Appendix B of both reports.

## 5.2 Processing and Use of Sold Product

Categories 10 and 11 represent the most material Scope 3 emission sources, accounting for over 92% of total Scope 3 emissions across both scenarios.

Category 10 (Processing of Sold Products): As detailed in Section 2.4.2.2, the Greenbase GHG Technical Reports quantify emissions from refining condensate into diesel and gasoline, applying a representative emission factor of 57.80 kg$CO_2$-e/bbl. The calculations appropriately account for the substantial difference in condensate production rates between scenarios:

- Case 1 (Lockyer only): 31,284 t$CO_2$-e/year (10.1 Sm$^3$/hour condensate production)
- Case 2 (Co-processing): 17,655 t$CO_2$-e/year (5.7 Sm$^3$/hour condensate production)

Category 11 (Use of Sold Products): This category represents the largest component of Scope 3 emissions, comprising combustion of sold natural gas (calculated using NGER Method 1 with emission factor of 51.53 kg$CO_2$-e/GJ) and combustion of refined condensate products. The methodology documented in Section 2.4.2.3 and Table 12 conservatively assumes complete combustion of all sold products, reflecting standard industry practice for estimating downstream emissions:

- Case 1 (Lockyer only): 3,992,894 t$CO_2$-e/year
- Case 2 (Co-processing): 3,926,967 t$CO_2$-e/year

Based on information provided the Scope 3 emission calculations have been verified as consistent with GHG Protocol requirements. The calculations appropriately reflect the documented project assumptions and are representative for this stage of the Project.

# 6. Emission Control Technology Review

The Project design incorporates several emissions-reduction technologies that demonstrate alignment with industry best practice and emissions minimisation principles. Each technology has been reviewed and assessed below based on documentation provided in the Greenbase GHG Technical Reports (Cases 1 and 2), historical Mineral Resources Lockyer Conventional Gas Project Energy Technology Peer Review (2024), and clarifications from Hancock Energy.

## 6.1 Acid Gas Removal Unit

The Project specifies a non-selective amine solution for $CO_2$ removal only, combined with a standalone $H_2S$ guard bed, as documented in Section 3.1 of the Mineral Resources Lockyer Conventional Gas Project Energy Technology Peer Review. This configuration is distinct from conventional combined $CO_2/H_2S$ removal amine systems and includes several advantages including:

- Selective $CO_2$ Extraction: Enables optimisation of $CO_2$ removal to precisely meet DBNGP pipeline specification ($CO_2 \leq 4.0$ mol%)[1] without over-extraction.
- Emissions Benefit: The Lockyer Energy Technology Peer Review (Section 4.1) confirms that Lockyer gas requires removal of only 0.5 mol% $CO_2$ compared to 2.35 mol% for West Erregulla, resulting in lower venting emissions.
- Energy Efficiency: As noted in Section 4.2 of the Lockyer Energy Technology Peer Review, smaller $CO_2$ removal requirements reduce amine circulation rates, lowering overall power requirements for pumps and reducing heat loads in air coolers.
- Technical Maturity: Both components are proven technologies widely deployed in conventional gas processing.

This AGRU configuration represents best available technology for the gas composition characteristics of the Lockyer and West Erregulla fields. The specification enables 0.5 mol% $CO_2$ removal for Case 1 (Lockyer only) and sufficient removal for Case 2 (blended gas) to meet DBNGP specifications while avoiding over-extraction of $CO_2$.

## 6.2 Reciprocating Engine Selection

The Project specifies reciprocating gas engines for on-site power generation rather than gas turbine alternatives, as detailed in Section 3.1 of the Mineral Resources Lockyer Conventional Gas Project Energy Technology Peer Review and confirmed in Section 4.5.2 of the BCGP Development Approval Summary.

Technical Basis:

- Reciprocating engine thermal efficiency: approximately 44.2% (Jenbacher J620 reference case).
- Gas turbine thermal efficiency: approximately 32.9% (Solar Mars 100 reference case).
- Direct result: Lower fuel consumption per unit of electrical output.

The Lockyer Conventional Gas Project Energy Technology Peer Review (Section 3.1, Table 3.1) demonstrates that reciprocating engines have a heat rate of 8.136 GJ/MWh compared to 10.934 GJ/MWh for gas turbines, resulting in approximately 20% emissions reduction. The selection of a reciprocating engine demonstrates commitment to best practice selection for gas processing facilities of this scale.

[1] Gas Supply (Gas Quality Specifications) Regulations 2010 - [00-a0-01].pdf

## 6.3 Flare Gas Recovery

The Project includes a recycle compressor to recover low-pressure hydrocarbon vapours from the condensate stabilisation system, returning these to the main gas plant for reprocessing.

Performance:

- Baseline flaring emissions (without recovery): approximately 1,300 $tCO_2$-e/year (estimated based on >95% reduction)
- Post-recovery flaring emissions: 624 $tCO_2$-e/year (Case 1); 675 $tCO_2$-e/year (Case 2)

As confirmed in Hancock Energy clarifications, flare emissions include purge, pilot, relief/blowdown, and enrichment gas used in the thermal oxidiser. The >95% reduction in potential flare emissions through vapour recovery demonstrates industry best practice for gas processing.

## 6.4 Thermal Oxidiser Integration

The AGRU waste stream contains Benzene, Toluene, Ethylbenzene, Xylene (BTEX) volatile organic compounds that require thermal destruction prior to venting. Section 3.2.2 of the Mineral Resources Lockyer Conventional Gas Project Energy Technology Peer Review confirms the thermal oxidiser operates at temperatures of 900-1200°C to ensure adequate destruction of hydrocarbons.

Thermal oxidation consumes additional fuel (natural gas enrichment) to reach destruction temperatures. As confirmed in Hancock Energy clarifications, enrichment gas emissions are captured in the flared gas category of the GHG assessment. The thermal oxidiser design reflects integrated environmental management for both air quality (BTEX destruction) and GHG emissions (waste heat recovery) and has been appropriately accounted for in the emissions calculations.

## 6.5 Alignment with Best Industry Practice

The emission control technologies implemented in the Project align with best industry practice and represent best available technology for the Project scale and gas composition characteristics:

1. Technology Selection Hierarchy: The Project prioritises emissions avoidance through efficient equipment selection (reciprocating engines, selective amine) before implementing emissions reduction measures (flare gas recovery).
2. Benchmarking: As documented in Section 3.2 of the Greenbase Technical Reports (Table 17), the Project's emission intensity of 0.9784 $tCO_2$-e/TJ (Case 1) and 1.1525 $tCO_2$-e/TJ (Case 2) compares favourably to similar Perth Basin projects:
    - West Erregulla: 3.03 $tCO_2$-e/TJ
    - Waitsia Stage 2: 3.29 $tCO_2$-e/TJ
    - Devil Creek: 1.56 $tCO_2$-e/TJ
    - Macedon: 1.50 $tCO_2$-e/TJ

Based on information and clarifications received from Hancock Energy and Greenbase, the emission control technologies have been verified as consistent with recognised industry best practices and represent appropriate technology selections for this Project scale and gas composition.

# 7. Gas Quality Effects and Blending Benefits

This section addresses how gas quality characteristics and blending specifically affect facility emissions for the combined Lockyer and West Erregulla gas scenario (Case 2), building on the gas property fundamentals described in Section 2.3.

## 7.1 West Erregulla Overview

The challenge with processing West Erregulla gas as a standalone facility stems from the dual requirement to meet DBNGP pipeline specifications for both $CO_2$ content and heating value.

West Erregulla well stream contains approximately 5.9 mol% $CO_2$ (as documented in Section 2.3.2) with minimal condensate fraction. To meet the DBNGP heating value specification, $CO_2$ must be over-extracted from the sales gas beyond what would be required solely to meet the $CO_2$ limit.

The West Erregulla GHG Environmental Management Plan (Revision 4, June 2023) states that standalone processing requires the removal of approximately 3.35 mol% $CO_2$ to reduce the well stream from 6.35 mol% to 3 mol% $CO_2$ in sales gas, rather than the approximate 2.0 mol% $CO_2$ removal required to simply meet the DBNGP 4.0 mol% $CO_2$ specification.

As a result of this, the West Erregulla Processing Plant and Pipeline (approved under Ministerial Statement 1229) operating at 87 TJ/day was estimated to generate approximately 96,319 $tCO_2$-e/year in Scope 1 emissions during long-term operations, as documented in the West Erregulla GHG Environmental Management Plan (Revision 4, June 2023) and referenced in Section 4.5.1 of the BCGP Development Approval Summary.

## 7.2 Co-processing Benefits

When 85 TJ/day of West Erregulla gas is co-processed with 125 TJ/day of Lockyer gas at the Project's facility (Case 2), the high condensate fraction in Lockyer gas provides heating value makeup that changes the processing requirements for West Erregulla gas. Blending Lockyer's high energy density gas with West Erregulla gas, this high condensate fraction increases the overall heating value of the combined stream, enabling the blended sales gas to meet DBNGP heating value specifications while removing only sufficient $CO_2$ to meet the $CO_2$ content limit, rather than over-extracting $CO_2$ to boost heating value artificially.

Table 7.1 highlights that BCGP Case 2 (Blended) total emissions (85,917 $tCO_2$-e/year) are lower than standalone West Erregulla processing (96,319 $tCO_2$-e/year for 87 TJ/day) despite processing 2.4 times the throughput (210 TJ/day vs 87 TJ/day). The emissions calculations appropriately capture these benefits and reflect the thermodynamic and process engineering benefits of optimising blended gas processing.

**Table 7.1 Emissions Comparison of Cases**

| Case | Facility Capacity | Total Scope 1 Emissions | Venting Emissions |
|---|---|---|---|
| West Erregulla Standalone | 87 TJ/day | 96,319 $tCO_2$-e/year[2] | 56,907 $tCO_2$-e/year |
| BCGP Case 1 (Lockyer only) | 210 TJ/day | 72,938 $tCO_2$-e/year | 22,441 $tCO_2$-e/year |
| BCGP Case 2 (Co-processing) | 210 TJ/day (125 Lockyer + 85 WE) | 85,917 $tCO_2$-e/year | 31,761 $tCO_2$-e/year |

The co-processing of West Erregulla gas with Lockyer gas delivers emission reduction benefits. The high condensate fraction in Lockyer gas enables West Erregulla processing at significantly reduced $CO_2$ extraction

[2] West Erregulla GHG Environmental Management Plan Revision 4, estimated annual emission year 3 onwards.

rates, eliminating the need for $CO_2$ over-extraction solely to meet DBNGP heating value specifications. This results in Case 2 emissions that are 10,402 $tCO_2$-e/year lower than standalone West Erregulla processing, despite processing 2.4 times the gas throughput.

# 8. Summary of Findings

This independent peer review of the GHG emissions calculations for the Project has identified the following key findings and conclusions.

### Calculation Verification

This review has applied professional judgement to assess the GHG emission quantification methodology for both Case 1 (Lockyer gas only at 210 TJ/day) and Case 2 (blended Lockyer and West Erregulla gas). The calculations correctly apply NGER methodologies based on information and clarifications received from Hancock Energy and Greenbase.

### Demonstration of Best Practice

The emission control technologies and design measures proposed for the Project align with both local and national industry best practices. Specifically:

- Selection of reciprocating gas engines for power generation.
- Implementation of selective amine technology for $CO_2$ removal.
- Inclusion of flare gas recovery systems.

These technologies demonstrate emissions minimisation through the mitigation hierarchy, prioritising avoidance and reduction in design.

### Emission Intensity Benchmarking

The Project's emission intensities compare favourably to similar Perth Basin projects:

- Case 1 (Lockyer only): 0.9784 $tCO_2$-e/TJ
- Case 2 (Co-processing): 1.1525 $tCO_2$-e/TJ

These results reflect the substantial investment in emissions-reducing technologies and the favourable characteristics of the Lockyer gas composition (low $CO_2$ content and high condensate fraction).

### Co-Processing Benefits

The co-processing of West Erregulla gas with Lockyer gas delivers emissions benefits. The Project's Case 2 emissions (85,917 $tCO_2$-e/year) are lower than those of the standalone West Erregulla facility (96,319 $tCO_2$- e/year), despite processing 2.4 times the throughput. This demonstrates the engineering optimisation achieved through blended gas processing.

### Conclusion

This independent peer review validates that the GHG emissions calculations for the Project are technically sound and appropriately apply NGER methodologies. The Project demonstrates a commitment to emissions minimisation through technology selection and strategic facility positioning that enable co-processing benefits with other gas fields. The assessment provides a technical foundation for regulatory submissions and environmental approvals.

# 9. Reviewer Credentials and Methodology

### Reviewer Credentials

Ashley Olsson | Managing Director and Principal Engineer, Evolveable Consulting

Ashley has over twenty years of experience in engineering design and environmental approvals for major projects in Western Australia and internationally. He has conducted several expert peer reviews of GHG emissions assessments for large-scale resource development and energy projects, with expertise in GHG quantification methodologies, Scope 3 emissions assessment, and decarbonisation strategies. Ashley holds a Bachelor of Engineering and Bachelor of Science and is a Chartered Environmental Engineer accredited through Engineers Australia.

### Review Methodology

In conducting this review, we have:

- Used professional judgement to assess the GHG emission quantification methodology for the Project along with the proposed emission reduction technologies.
- Reviewed credible technical documentation including the Greenbase GHG Technical Reports, the Mineral Resources Lockyer Conventional Gas Project Energy Technology Peer Review, and relevant NGER methodologies.
- Ensured that the review team possessed appropriate knowledge, skills and professional competencies in gas processing facility design and GHG assessment.

### Scope and Limitations

This Peer Review Report has been prepared for Hancock Energy to provide conclusions on the technical basis for GHG emissions quantification, it may not be suitable for any other purpose.

This Peer Review is based on our current understanding and knowledge of the information provided, which may evolve over time. We make no express or implied representations or warranties regarding the accuracy or completeness of the conclusions in this report beyond the scope of the review as documented. We disclaim any assumption of responsibility for any reliance on this report beyond its intended use.

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