Table 1: Lockyer Conventional Gas Project Request for Further Information APP-0025169

Item	EPA request	MinRes response
1a	ERL considers providing a brief peer review of the proposed technologies used for reducing GHG emissions.	MinRes engaged GHD, a multi-national and highly experienced engineering and environmental consultancy, to conduct a peer review of the proposed technologies. The GHD report is provided as **Appendix A**.
1b	The EPA seeks a breakdown of the sources of emissions presented within GHG assessment technical report ensuring that the information presented is similar to other conventional gas projects in the surrounding areas.	MinRes has compiled a breakdown of the sources of greenhouse gas emissions, measured as tCO2-e, in comparison with similar conventional gas projects in the surrounding area i.e. the West Erregulla Processing Plant and Pipeline, and the Waitsia Gas Project. This information is provided as **Appendix B**. The tCO2-e emissions comparison was limited to publicly available information.
1c	ERL review the Referral Supporting Document, and the presentation of some measurement data. Specifically of note is that the scale of emission intensity changes between tCO2-e/GJ to tCO2-e/TJ (see sections 10.7.3, 10.7.4 and Table 10-6).	Upon review of the Referral Supporting Document, it has been determined the units used in the text are a typographical error carried over from a consultant report. MinRes confirms all units should be expressed as tCO2-e/TJ. The amended report *Lockyer Gas Development Project: Greenhouse Gas Assessment Technical Report v1.3* (Greenbase 2024) is provided as **Appendix C**.
2	Evidence of attempts to, or consultation with, the Traditional Owners in relation to activities proposed in proximity to the Lockier River and Irwin River.	Evidence of MinRes' consultation with the Traditional Owners in relation to activities proposed in proximity to the Lockier and Irwin Rivers includes: • MinRes presentation to the Yamatji Southern Regional Corporation Ltd (YSRC) Cultural Committee on 18 January 2024. Presentation slides are provided as **Appendix D**. • MinRes Briefing Paper provided to the YSRC in January 2024 is provided as **Appendix E**. • YSRC letter of support for the MinRes Lockyer Conventional Gas Project and level of engagement is provided as **Appendix F**.
3	Provide a brief justification that there is unlikely to be a change to the conservation status of *Austrostipa nunaginensis* (Priority 3 species) as a result of the proposed clearing activities.	MinRes engaged a specialist consultant, Eco Logical Australia (ELA), to review the likelihood of change to the conservation status of the *Austrostipa nunaginensis.* The result of the review concludes the proposal is considered unlikely to change the conservation status of *Austrostipa nunaginensis* as a result of the proposed clearing activities. The consultant memo is provided as **Appendix G.**

Item	EPA request	MinRes response
Supplementary RFI		
4	Further information was requested on the potential impacts of the Project on *Lepisosperma* sp. Nov.	As per JBS&G (2024), *Lepidosperma* sp. Nov. is a potentially undescribed species, due to the disarray of *Lepidosperma* vouchers at the Western Australian Herbarium, impeding accurate identification to species level. Though, it has been previously collected from the Arrowsmith/ Mt Adams area. As a preventative measure, MinRes will commit to retainment and protection of the single individual *Lepidosperma* sp. Nov identified within the Development Envelope, inclusive of barrier fencing (10 metre buffer) during construction works. The 10m buffer zone will be formalised within the Environment Plan, prepared in accordance with the Petroleum and Geothermal Energy Resources (Environment) Regulations 2012, and subject to the approval of the Department of Energy, Mines, Industry Regulation and Safety.
5	Further clarification was requested on the impact of noise from the Project on Sensitive Receiver – 25116 Midlands Road, Mount Horner and compliance with the *Environmental Protection (Noise) Regulations 1997.*	The *Environmental Protection (Noise) Regulations 1997* do not extend to the Sensitive Receiver located at 25116 Midlands Road, Mount Horner, given its presence within the same property premises. Nonetheless, according to findings in Lloyd George Acoustics (2023; Appendix K of the Supporting Document) and Table 12.5 of the Supporting Document, any impacts on the Sensitive Receiver align with the stipulations of the Environmental Protection (Noise) Regulations 1997. If considered a highly sensitive area during evening hours (2200-0700), the predicted L_{A10} is 35 dB, in line with the Controlled L_{A10} limit. Furthermore, the predicted L_{A1} is 39 dB (potential noise occurring during a gas flare discharge present for <1% of the time, during an emergency), is also below Controlled L_{A1} levels of 45 dB. Therefore, the predicted noise levels will also be Compliant with assigned levels at all times for this Sensitive Receiver.

APPENDIX A
LOCKYER CONVENTIONAL GAS PROJECT ENERGY TECHNOLOGY PEER REVIEW (GHD 2024)

Peer Review Report

Lockyer Conventional Gas Project Energy Technology Peer Review

Mineral Resources Limited (MinRes)

April 12, 2024

→ **The Power of Commitment**

Project name		MinRes – Lockyer Conventional Gas Project Energy Technology Peer Review					
Document title		Peer Review Report | Lockyer Conventional Gas Project Energy Technology Peer Review					
Project number		12621021					
File name		12621021- GHD-00-00-RPT-ZZ-00001_1.docx					
Status Code	Revision	Author	Reviewer		Approved for issue		
			Name	Signature	Name	Signature	Date
S4	1	Yurong Liu	Nim Gnanendran		Michele Villa		12/04/2024

GHD Pty Ltd ABN 39 008 488 373
999 Hay Street, Level 10
Perth, Western Australia 6000, Australia
T +61 8 6222 8222 | **F** +61 8 6222 8555 | **E** permail@ghd.com | **ghd.com**

The Power of Commitment

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Executive Summary

Mineral Resources Limited (MinRes) is proposing the Lockyer Conventional Gas Project in the mid-west region of Western Australia. MinRes engaged GHD to provide a peer review of the proposed energy technologies for the Lockyer Conventional Gas Plant which has a design capacity of up to 250 TJ/day and is estimated to have a total 78,198 tCO2e/year of Scope 1 emissions.

The objective of the peer review is to assess the technologies used in the Lockyer Conventional Gas Project and determine whether they are best suited to minimise greenhouse gas (GHG) emissions.

The scope of the peer review is focused on the top contributors in the plant (other than reservoir gas CO_2) namely onsite power generation, heating medium, and incinerator/thermal oxidizer.

The selected power generation option with reciprocating engine can reduce emissions compared to the alternative gas turbine option due to the inherently higher thermal efficiency of a reciprocating engine. That is, a reciprocating engine in general will use less fuel gas to generate the same unit of power when compared to a gas turbine.

The heating medium system in the Lockyer Conventional Gas Project is proposed to be fully supplemented by waste heat recovery units attached to the gas engine generators and thermal oxidiser. This allows for the reduction of GHG emissions compared to the utilisation of gas fired heaters or other heating options and will result in lower GHG emissions at the Lockyer Conventional Gas Plant.

The plant design has also considered temperature/heat diagrams and analysed the heat transfer potential between all hot and cold streams. Based on this analysis, the gas-gas exchanger was included in the design to utilise reservoir gas (hot) to preheat the mercury guard bed inlet stream (cold). This negates the requirement for additional heating using fuel gas or heating medium, in turn reducing overall emissions.

In summary, MinRes has chosen an effective approach to design a facility that minimises GHG emissions as the first and most effective step in the GHG mitigation hierarchy.

1. Introduction

Energy Resources Limited, a wholly owned subsidiary of Mineral Resources Limited (MinRes) is proposing the Lockyer Conventional Gas Project in the mid-west region of Western Australia. The Lockyer Conventional Gas Plant has a design capacity of up to 250 TJ/day and is estimated to have a total 78,198 tCO2e/year of Scope 1 emissions as per the *Environmental Protection Act 1986* Part IV Section 38 Referral Supporting Document submitted by MinRes to the Environmental Protection Authority (EPA) in March 2024.

The proposed Lockyer Gas Plant greenhouse gas (GHG) emissions are estimated to be lower than similar gas plants in the region due to the lower carbon dioxide (CO_2) in the reservoir gas and the energy technologies selected.

This report by GHD provides a peer review of the proposed energy technologies for the Lockyer Conventional Gas Plant based on the emissions estimates reported in the MinRes Lockyer Conventional Gas Project application submitted to the EPA in March 2024.

MinRes engaged GHD, a global multi-national and highly experienced engineering and environmental consultancy, to conduct a peer review of the proposed technologies. **This report has been prepared by Nim Gnanendran, Technical Director – Decarbonisation and Yurong Liu, Process Engineer at GHD. A summary of the author's credentials is provided in Section 6.**

1.1 Purpose of this report

The purpose of this report is to provide a brief peer review to the EPA of the proposed technologies used for reducing GHG emissions as reported in the Referral Supporting Document submitted by MinRes to the EPA in March 2024.

1.2 Scope

GHD was engaged by MineRes to provide a technical peer review and brief report of the proposed technologies for Lockyer, as requested by the EPA: "*It is therefore recommended that ERL considers providing a brief peer review of the technologies used to reduce GHG emissions*".

Peer review of the GHG emissions estimates and assessment is excluded from this report.

1.3 Assumptions

The review was based on a desktop review only. No site visit was undertaken for this assessment.

This report is based on the proposed design for the Lockyer Conventional Gas Plant as per the extracts of the Design Basis and preliminary Process Flow Diagrams provided by MinRes (Rev B- Sept 2023).

This report assumes the greenhouse gas emissions estimates already provided by MinRes to the EPA are accurate at the stage of preparing this report.

1.4 Methodology

The following approach was adopted by GHD in completing this peer review:

- High-level review of the Lockyer Conventional Gas Plant preliminary design documents provided by MinRes (See Section 7) and considered the individual parts and aspects that make up the design of the facility.
- Investigate the claims MinRes have made regarding the appropriateness of the GHG reductions resulting from the chosen technology and reservoir CO_2 levels.

2. Background

Mineral Resources Limited (MinRes) is proposing the Lockyer Conventional Gas Project in the mid-west region of Western Australia within petroleum Exploration Permit (EP) 368 for the transport, processing, and supply of natural gas. MinRes is taking a proactive approach to design a facility that minimises GHG emissions from the outset of the project by implementing avoidance measures and using best practice design as the first and most effective step in the mitigation hierarchy. As part of this approach, MinRes has carried out feasibility studies to assess and identify the abatement opportunities and alternative technologies.

The EPA has acknowledged the efforts undertaken by MinRes to reduce GHG emissions by using effective energy technologies, which has resulted in the expected GHG emissions of the project being lower than those of similar projects in the region. It was therefore recommended that MinRes considers providing a brief peer review of the proposed technologies used for reducing GHG emissions at the Lockyer Conventional Gas Plant.

GHD has undertaken a peer review of the proposed energy technologies outlined in the MinRes EPA submission for the proposed Lockyer Conventional Gas Project.

3. Lockyer Conventional Gas Plant Design

A typical gas processing plant consists of pretreatment units such as an acid gas removal unit, mercury removal, dehydration/dewpointing unit and compression units to refine the reservoir gas to meet the necessary gas pipeline specifications. The gas processing plant also consumes heat and power, which are generated onsite using part of the treated gas, resulting in post-combustion emissions.

The proposed design for Lockyer Conventional Gas Plant uses electric motor driven compressors as opposed to gas engine driven compressors. Therefore, there are no associated emissions for export gas compression but the use of electric motor drives has shifted the GHG emissions quantity to the onsite power generation emissions. The Lockyer Conventional Gas Project uses a series of gas reciprocating engines rather than gas turbines to generate power due to their higher thermal efficiency.

The heating medium system provides hot oil to users such as the acid gas removal unit (amine reboiler), Monoethylene Glycol (MEG) regeneration package (MEG reboiler), and condensate stabilization unit (condensate reboiler).

The Lockyer Conventional Gas Project has chosen to implement the use of waste heat recovery units to extract heat from combustion engines (gas generators) as well as the thermal oxidiser. This integration of waste heat recovery with the onsite centralised power generation and thermal oxidiser can provide all the heat requirements of the Lockyer Conventional Gas Plant, thereby reducing fuel gas consumption and overall GHG emissions.

Venting of reservoir carbon dioxide (CO_2) removed via the acid gas removal unit is typically required. Reservoir CO_2 is normally accompanied by Benzene, Toluene, Ethylene, and Xylene (BTEX) components which are required to be thermally destructed via an incinerator or thermal oxidiser.

3.1 Power Generation

Gas plants typically use a series of gas reciprocating engines or gas turbines to generate power for plant use. The proposed Lockyer Conventional Gas Project utilises gas reciprocating engines for power generation rather than gas turbines to meet the required plant power requirements.

A gas reciprocating engine, also commonly referred to as a piston engine, is an internal combustion engine (ICE) that operates by converting the heat and pressure released during combustion of fuel mixed with air into mechanical energy. The reciprocating engine combusts natural gas, producing hot, high-pressure gas that drives pistons within cylinders, converting linear motion into rotary motion via the crankshaft, ultimately powering the generator to produce electricity. For power generation applications, reciprocating engines are coupled to a generator on the same base frame. Gas engines generally have lower power ratings, therefore the onsite power generation system can operate at a reduced plant load by using only a portion of the engine fleet at full load, maximizing thermal efficiency.

Gas turbines, another type of internal combustion engine (ICE), are one of the most widely used power generation technologies today. Gas turbines draw in ambient air, compress it, mix it with fuel, and ignite the mixture to create high-pressure, high-temperature gas. This gas then drives turbine blades, connected to a generator, producing electricity as it spins the rotor.

Either gas reciprocating engines or gas turbines (suitably sized) could be used to meet the power requirement of the Lockyer gas plant. Both technologies were evaluated, with a focus on selecting the most efficient solution over the expected lifetime of the plant and the forecast power demand, also considering the future inlet compression loads.

Table 3.1 provides a comparison of the potential choice of gas engine and gas turbine options that may be utilised for the proposed plant to meet the total power demand of approximately 12.2 MW, as advised by MinRes. Note that the final selection of the gas engine vendor is assumed to be subject to commercial agreements.

Table 3.1 Reciprocating Engines versus Gas Turbines for power generation

	Reciprocating Engines	Gas Turbine
Machine Example	*Jenbacher J620 unit*[1]	Solar Mars 100 Turbine[2]
Rated Power (kW)	3,360	11,350
Heat Rate at Rated Power, GJ/MWhe (LHV)	8.136	10.934
Thermal Efficiency % (at rated power)	44.2%	32.9%

The proposed Lockyer Conventional Gas Project utilises a combined heat and power (CHP) arrangement, which is also known as cogeneration. CHP is a system that generates electricity while using the residual heat generated in the process for residual heating or other applications. Figure 3.1 shows a typical CHP plant arrangement consisting of a reciprocating engine, an electricity generator, and a heat recovery system.

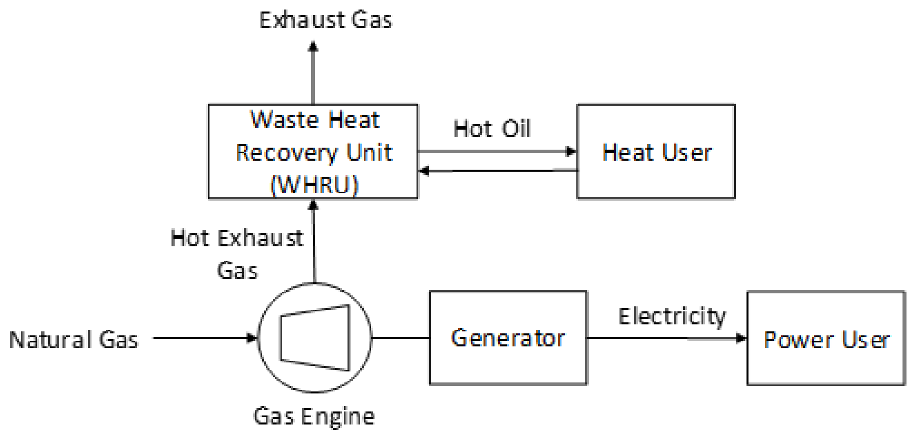

Figure 3.1 Combined Heat and Power Plant arrangement.

CHP systems reduce CO_2 emissions by utilising fuel more efficiently than conventional separate heat and power generation systems. By capturing and utilising waste heat from electricity generation for heating purposes, CHP systems avoid the additional fuel consumption that would be required to generate the same amount of heat using separate boilers or furnaces. This results in lower CO_2 emissions per unit of useful energy produced.

In conclusion, the selected power generation option with reciprocating engine and waste heat recovery units allows for the reduction in emissions more than the alternative gas turbine option (also assumed with waste heat recovery) and this will result in lower CO_2 emissions at the Lockyer Conventional Gas Plant due to a combination of inherently higher thermal efficiency of the gas engine and removing the need to burn additional fuel gas for plant heat.

3.2 Heat Generation

The heat requirements in the Lockyer Conventional Gas Plant are met from waste heat recovery units (WHRUs) attached to, (1) gas engine exhausts and (2) thermal oxidiser exhaust along with a small start-up gas fired heater.

3.2.1 Gas Engine - Waste Heat Recovery Unit

The economics of engines for on-site power generation applications often relies on the effective use of the thermal energy contained in the exhaust gas and cooling systems, which generally represents between 60% and 70% of the inlet fuel energy. Engine exhaust heat represents between 30% and 50% of the available waste heat. The most

[1] **Jenbacher J620 Gas Engine | Products | Jenbacher**
[2] **Mars 100 (solarturbines.com)**

common method of recovering engine heat is the closed-loop cooling system. These systems are designed to cool the engine by forced circulation of a coolant (e.g., thermal oil) through engine passages and an external heat exchanger. Figure 3.2 shows a typical diagram of reciprocating gas engines integrated with a WHRU.

In the Lockyer Conventional Gas Plant's CHP, a WHRU is utilised to capture/recover waste heat from the combustion system's exhaust stream. After the combustion process in the reciprocating engine, hot exhaust gases are produced as a byproduct. The WHRU captures this waste heat and transfers it to thermal oil as a heat exchange medium. As such, the waste heat is converted into useful thermal energy in hot oil, improving energy efficiency and reducing energy costs.

The waste heat recovered by the WHRU is used to provide the heating demand of the gas plant. As a result, the utilisation of WHRU avoids the additional fuel consumption that would be required to generate the same amount of heat using the gas fired heater, which can reduce GHG emissions.

In conclusion, the selection of a WHRU allows for the reduction of GHG emissions at the Lockyer Conventional Gas Plant.

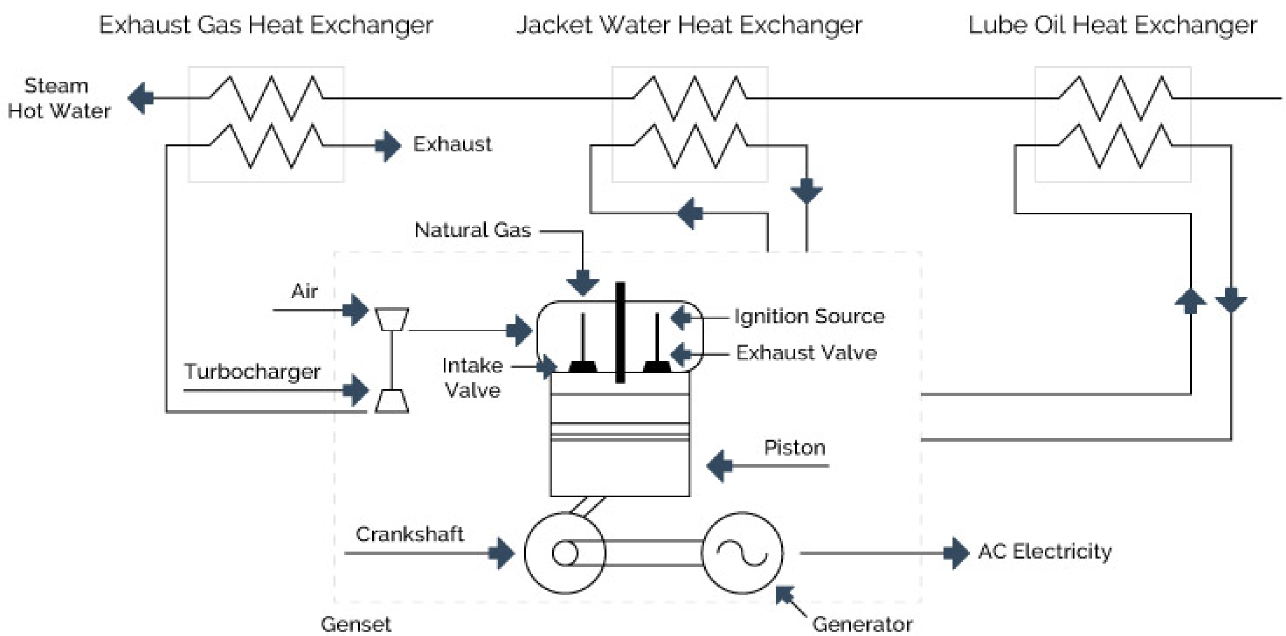

Figure 3.2 Reciprocating Gas Engines with Waste Heat Recovery Unit

3.2.2 Thermal Oxidiser - Waste Heat Recovery Unit

A thermal oxidiser is used in the gas plant to incinerate any BTEX and volatile hydrocarbons present in the CO_2 vent from the Acid Gas Removal Unit and the regenerator vent gas from the Monoethylene Glycol (MEG) dehydration unit. A thermal oxidiser unit (afterburner type) uses a small volume of fuel gas to incinerate these gases between 900 and 1200°C, ensuring adequate destruction of the harmful hydrocarbons is achieved prior to venting.

See Figure 3.3 for the integrated system of a thermal oxidiser with waste heat recovery unit.

The waste heat from the flue gas existing the thermal oxidiser unit is recovered using a hot oil circuit such that this high grade heat can be used to supplement the heat requirements of the acid gas removal unit, MEG dehydration unit within the gas plant.

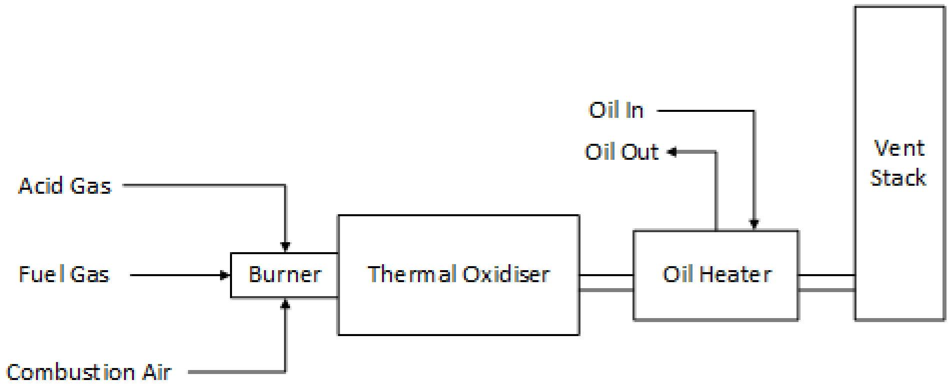

Figure 3.3 *Thermal Oxidiser with Waste Heat Recovery Unit*

In conclusion, the use of WHRU integrated with a thermal oxidiser allows for the reduction of GHG emissions compared to the utilisation of gas fired heaters or other heating options and will result in lower CO_2 emissions at the Lockyer Conventional Gas Plant.

3.3 Heat Integration (Gas-Gas Exchanger)

An efficient process plant design considers temperature/heat diagrams (composite curves) to visualize available hot stream, cold streams and the heat transfer potential between them. Based on such an analysis the Lockyer Conventional Gas Plant design utilises a gas-gas exchanger to transfer heat from the incoming reservoir gas to the inlet stream to the Mercury guard beds, this avoids the need for installing additional heating in the gas plant, while in turn reducing overall emissions.

The Mercury guard beds remove any trace amount of mercury that may be present in the reservoir gas, and feed gas entering the unit after the inlet separator in the plant is required to be superheated to avoid any liquids in the gas, superheating of the gas protects the mercury guard bed catalyst from degrading while ensuring the guard beds perform as per design requirement.

In conclusion, the use of gas-gas exchanger allows for the reduction of GHG emissions compared to the alternative utilisation of gas fired heaters or other heating options at the Lockyer Conventional Gas Plant.

4. Reservoir Gas CO_2 Removal

The Lockyer reservoir gas compositional data measures from three gas well tests provided by MinRes and indicates a CO_2 composition range of between 3.4 and 3.9 mol%. The Dampier to Bunbury Natural Gas Pipeline (DBNGP) pipeline specifications maximum of 4.0 mol%[3] with total inert gases limit of 7.0 mol%. Therefore, in theory, the gas process plant need not have to remove and vent CO_2 of the reservoir gas. However, as a conservative measure, the Lockyer Conventional Gas Plant design is based on the removal 0.5 mol% of CO_2 from the up to 250 TJ/d gas plant to estimate its annual reservoir CO_2 emissions.

4.1 Lockyer Reservoir Gas CO_2 versus Other Perth Basin Reservoir Gas CO_2

Table 4.1 provides a summary of reservoir gas CO_2 compositional data of the nearby gas reservoirs compared to the Lockyer gas reservoir.

Table 4.1 Reservoir gas CO_2 composition comparison

Project Gas Reservoir	CO_2 Composition	Reference
Lockyer	3.4 to 3.9 mol%	MinRes
Waitsia	4.5 - 7.5 mol% (average 6.0 mol%)	GHG Report (EPA WA, 2020)[4]
West Erregulla	6.36 mol%	GHG Report (EPA WA, 2022)[5]

Lockyer Conventional Gas Plant is designed to remove 0.5 mol% CO2 from the feed gas. The Waitsia gas plant would be required to remove 3.5 mol% CO_2 and the West Erregulla plant would be required to remove 2.35 mol% of the CO_2 from the feed gas.

In conclusion the lower CO_2 content in the Lockyer gas reservoir allows for the reduction in a lower CO_2 emissions intensity (tonnes reservoir CO2e/TJ gas export) at the Lockyer Conventional Gas Plant.

4.2 Acid Gas Removal Unit Heat and Power Demand

The Acid Gas Removal Unit (AGRU) in a gas plant consumes heat to regenerate the amine solvent, the typical heat requirement varies between 2.0 and 3.0 GJ/tonne CO_2 removed from the AGRU[6]. Typically, this heat is supplied via gas fired heaters. A smaller CO_2 removal requirement associated with the Lockyer gas reservoir enables a much smaller AGRU to be installed with a smaller overall heat requirement in the Lockyer Conventional Gas Plant. Therefore, enabling the heat load to be met via a WHRU rather than additional gas fired heaters.

A smaller CO_2 removal requirement also reduces amine circulation rates in an acid gas removal unit reducing overall power requirements for the pumps along with smaller heat loads in air coolers and reflux condensers reducing fan power loads.

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[3] DBNGP Specifications **https://www.legislation.wa.gov.au/legislation/prod/filestore.nsf/FileURL/mrdoc_17704.pdf/$FILE/Gas%20Supply%20(Gas%20Quality%20Specifications)%20Regulations%202010%20-%20%5B00-a0-01%5D.pdf?OpenElement**

[4] **https://www.epa.wa.gov.au/sites/default/files/PER_documentation2/Greenhouse%20Gas%20Management%20Plan.pdf**

[5] https://www.epa.wa.gov.au/sites/default/files/PER_documentation2/Appendix%20I%20-%20Greenhouse%20Gas%20Management%20Plan%20Rev%202.pdf

[6] CCS Technologies **https://www.globalccsinstitute.com/wp-content/uploads/2023/10/State-of-the-Art-CCS-Technologies-2023_09_Final.pdf**

5. Concluding Remarks

This peer review was undertaken by qualified GHD personnel as listed in Section 6 of this report of the energy technologies proposed for the Lockyer Conventional Gas Project provides the following key features,

- The selection of reciprocating gas engines for power generation with proven lower heat rate and higher thermal efficiency allows for the reduction of GHG emissions associated with power generation on site compared to the alternative technology of gas turbine engines.
- The use of waste heat recovery units attached to the gas reciprocating engines in a combined heat and power arrangement results in part of the plant process heat requirements being met from otherwise wasted energy. The use of a waste heat recovery unit attached to the Thermal Oxidiser unit also provides additional heat source. These waste heat recovery units can avoid the need for separate gas fired heaters being used in the plant allowing for the reduction in emissions in the plant.
- The reservoir CO_2 content of the Lockyer gas reservoir is between 3.4 and 3.9 mol% as per initial well test data, which requires minimal CO_2 removal, compared to a gas plant with higher CO_2 (up to 7.5 mol%) in the reservoir gas in the region, to meet the 4.0 mol% DBNGP pipeline CO_2 specification. Therefore, emissions intensities associated with reservoir CO_2 venting will be lower for the Lockyer Conventional Gas Plant compared to other similar gas plants in the region.

In summary, a combination of lower reservoir gas CO_2 content, use of energy efficient waste heat recovery units in all available high grade heat sources in the plant, use of gas-gas exchangers between appropriate hot and cold streams and the selection of efficient gas engines for power generation for the Lockyer Conventional Gas Project allows for the reduction in GHG emissions.

6. Author's Credentials

Nim Gnanendran | Technical Director GHD

Nim has over 20 years of experience in gas and LNG processing, holding senior process engineering and technology manager roles over his career. He has been involved in LNG project development in Queensland, Australia, Louisiana, US and Nova Scotia, Canada including working with multi-national EPC contractors in FEEDs for LNG export facilities. Experience also includes working with development and commercialisation of novel process technologies in low-carbon mid-scale LNG trains and cryogenic CO_2 capture for CCS. Nim's recent consulting experience includes working on decarbonisation initiatives for mining, manufacturing and energy clients, including carbon capture, e-methane, thermal energy storage and renewable diesel based concept studies. Nim holds a Ph.D. in Gas Processing (Curtin University, Perth) and a Bacher of Engineering (Chemical and Process) from University of Moratuwa, Sri Lanka and is an Associated Member of the Institute of Chemical Engineers UK.

Yurong Liu | Process Engineer GHD

Yurong is a process engineer with six years of research experience in renewable energy technologies including bioenergy production (biomass gasification), thermal energy storage, and hydrogen storage. Yurong has co-authored more than 15 publications in thermal energy storage and bioenergy technologies. She has worked on several projects including thermal energy storage technology assessment, thermal energy storage system integration, and carbon capture plant design, green hydrogen feasibility study, renewable methanation plant design, mineral carbonisation, and biological CO_2 fixation. Yurong holds a Ph.D. in Chemical Engineering (Curtin University. Perth) and a Master of Professional Engineering in Material Science and Engineering from Nanjing University, China. Yurong is a certified Professional Material Engineer from Engineers Australia.

7. References

(1) Environmental Protection Act 1986 Part IV Section 38 MinRes Referral Supporting Document (March 2024).

(2) Waitsia Gas Project Stage 2- Greenhouse Gas Management Plan (April 2020).

(3) West Erregulla Processing Plant and Pipeline Greenhouse Gas Management Plan (April 2022).

(4) Lockyer Gas Plant Process Flow Diagrams Rev B, Mineral Resources (Oct 2023).

(5) Lockyer Gas Plant Basis of Design - Extracts, Mineral Resources (Oct 2023).

(6) Lockyer Reservoir Well Test Compositional Data (2023).

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APPENDIX B
MINRES FACILITY EMISSION SOURCES COMPARISON

Figure 1. Facility Emission Sources Comparison

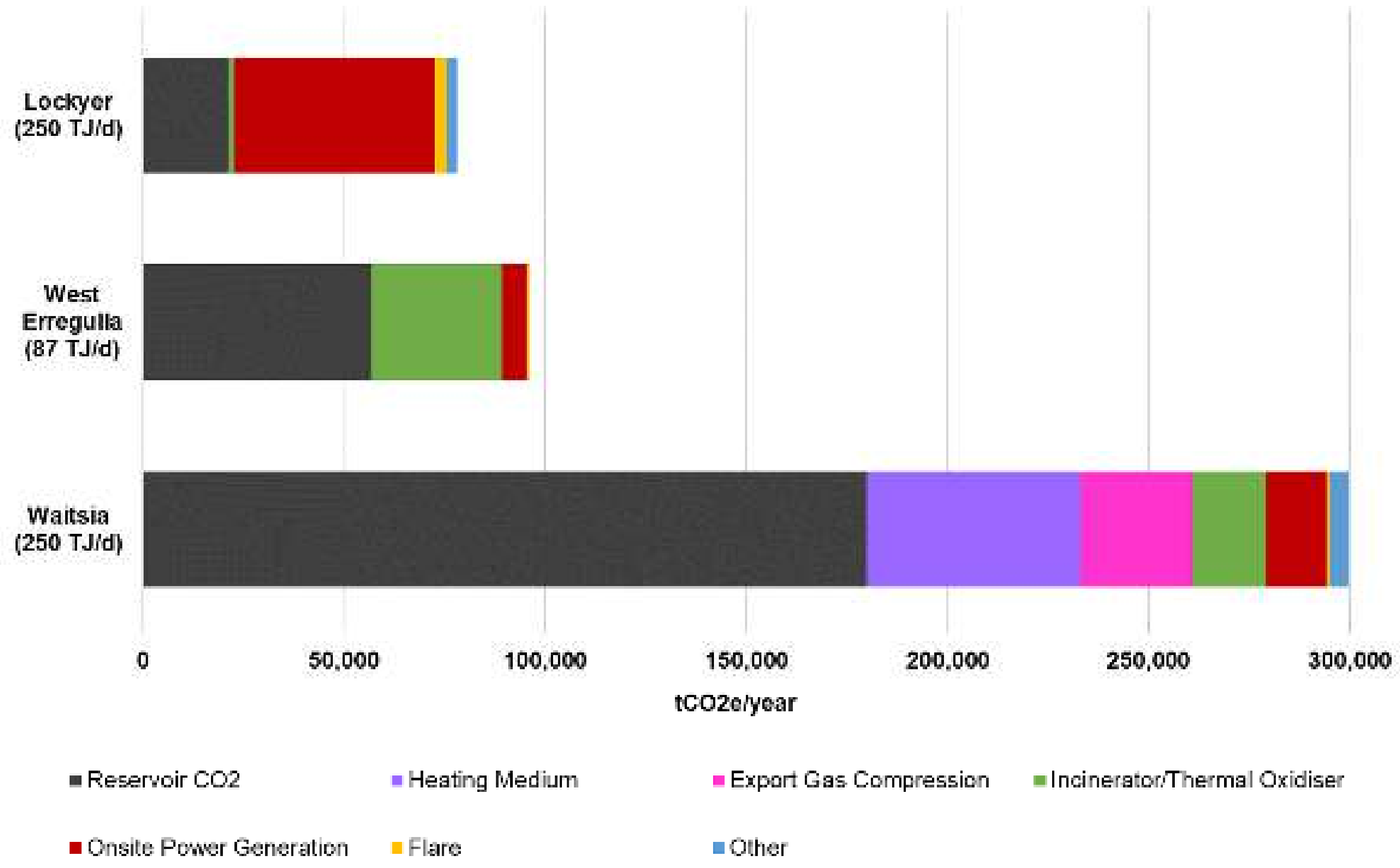

Table 1. Facility Emission Sources Comparison

CO_2 emission source	Lockyer (tCO2-e/year) Facility capacity (proposed): 250 TJ/d	Waitsia (tCO2-e/year) Facility capacity: 250 TJ/d	West Erregulla (tCO2-e/year) Facility capacity: 87 TJ/d	MinRes remarks
Reservoir emissions	21,031 *Equivalent to removing 0.24 tCO2-e/TJ of gas processed*	180,000 *Equivalent to removing 2.0 tCO2-e/TJ of gas processed*	56,907 *Equivalent to removing 1.8 tCO2-e/TJ of gas processed*	The Lockyer Gas Plant (LGP) uses an Acid Gas Removal Unit (AGRU) to reduce carbon dioxide (CO_2) in the sales gas. Based on laboratory analysis of the wells drilled to date, the LGP feedstock CO_2 composition is between 3.4 and 3.9 mol%. Minimal CO_2 removal is required in the LGP processing facility to meet the Dampier to Bunbury Natural Gas Pipeline (DBNGP) pipeline specification for CO_2 content (which is 4.0 mol%), with a small margin assumed to ensure commercial contractual conditions on CO_2 content are met. The LGP estimate of 21,031 tCO_2-e/year is based on removing 0.5 mol% CO_2 from all feed gas resulting in a pipeline gas CO_2 content of 3.5 mol% or lower. This is equivalent to removing 0.24 tCO_2-e/TJ of gas processed. The LGP design is optimised to allow bypassing of the AGRU completely when the feedstock gas is at the lower end of the measured composition (i.e. between 3.4 and 3.7 mol%). There will be no reservoir CO_2 emissions if the AGRU is fully bypassed, and all other DBNGP pipeline quality specifications (e.g., high heating value) can be met by the LGP gas with the AGRU fully bypassed. The Waitsia gas plant reported a feedstock CO_2 range of 4.5 mol% to 7.5 mol%[1] , which means a requirement to remove ~3.5 mol% of CO_2 to meet the DBNGP pipeline specification. The estimated 180,000 tCO2-e/year is equivalent to removing 2 tCO_2-e/TJ of gas, noting that further CO_2 removal may be required to meet other DBNGP pipeline gas quality specifications, depending on the composition and processing facilities included in the Waitsia gas plant. The Waitsia gas plant is removing ~8.5 times the tCO_2-e/TJ compared with gas processed at the LGP.

CO_2 emission source	Lockyer (tCO2-e/year) Facility capacity (proposed): 250 TJ/d	Waitsia (tCO2-e/year) Facility capacity: 250 TJ/d	West Erregulla (tCO2-e/year) Facility capacity: 87 TJ/d	MinRes remarks
				The West Erregulla gas plant reported a feedstock CO_2 content of 6.35 mol%[2] which means there is a requirement to remove at least 2.35 mol% of CO_2 to meet the DBNGP pipeline specification. The estimated 56,907 tCO_2-e/year is equivalent to removing 1.8 tCO_2-e/TJ, noting that further CO_2 removal may be required to meet other DBNGP pipeline gas quality specifications, depending on the composition and processing facilities included in the West Erregulla gas plant. The West Erregulla gas plant is removing ~7.8 times the tCO2-e/TJ compared with gas processed at the LGP.
Heating medium emissions	Nil	53,000	Nil	The LGP has no emissions attributed to the heating medium system due to waste heat recovery units (WHRU's) installed on the onsite gas generators and the thermal oxidiser. Heat recovery from these systems is high enough to provide plant heating to all users including the amine, mono ethylene glycol and condensate stabiliser reboilers in the plant. The LGP heating load is small compared to the Waitsia gas plant as the size of the Amine reboiler is directly related to the amount of reservoir CO_2 that is removed from the gas. That is, reducing CO_2 removal from the gas reduces the amine reboiler size. The Waitsia gas plant removes ~8.5 times the reservoir emissions of the LGP. This means that the Waitsia gas plant will have a significantly higher amine reboiler load as well as other heating medium users within the plant. The Waitsia gas plant heat load cannot be fully met by the WHRU's and the Waitsia gas plant uses a direct fired heater which burns fuel gas to generate the heat required to supply heat to the system. The West Erregulla gas plant has nil emissions attributed to the Heating Medium system due to using a hot oil system combined with the thermal oxidiser. Similar to the LGP, the West Erregulla gas plant is able to provide sufficient heat to the gas plant by using waste heat from the thermal oxidiser which incinerates the acid

CO_2 emission source	Lockyer (tCO2-e/year) Facility capacity (proposed): 250 TJ/d	Waitsia (tCO2-e/year) Facility capacity: 250 TJ/d	West Erregulla (tCO2-e/year) Facility capacity: 87 TJ/d	MinRes remarks
				gas from the AGRU, and a separate direct fired heating medium heater is not required.
Export gas compression emissions	Nil	27,800	Nil	The LGP has no emissions in this category as the Export Gas Compressors are electric motor driven. The compressor duty (and associated emissions) is included the total plant load and is accounted for in 'onsite power generation'. The Waitsia gas plant utilises gas engine driven compressors to compress sales quality gas to the DBNGP operating pressure. This results in the emissions value as shown. The West Erregulla gas plant utilises Silica Gel[3] for hydrocarbon dewpointing. This technology does not require a reduction in gas pressure within the facility, negating the requirement to install export compression. This plant is not directly comparable to either the LGP or the Waitsia gas plant in this regard.
Incinerator (or Thermal Oxidiser) emissions	1,732	18,300	32,354	Fuel gas enrichment is required to thermally destruct Benzene, Toluene, Ethylene, and Xylene in the acid gas stream from the AGRU. This ensures the air quality specifications are met. The LGP removes 21,031 tCO2-e/year and requires 1,732 tCO2-e/year of additional fuel gas to the incinerator. The additional emissions attributed to the fuel gas enrichment is approximately 8.2% of the acid gas emissions. The Waitsia gas plant removes 180,000 tCO2-e/year and requires 18,300 tCO2-e/year of additional fuel gas to the incinerator. The additional emissions attributed to the fuel gas enrichment is approximately 10% of the acid gas emissions. Proportionally higher (than the LGP) fuel gas enrichment is required to ensure full thermal destruction. The West Erregulla gas plant removes 56,907 tCO2-e/year and requires 32,354 tCO2-e/year of additional fuel gas to the incinerator. The additional emissions attributed to the fuel gas enrichment is approximately 56.9% of the acid gas emissions.

CO_2 emission source	Lockyer (tCO2-e/year) Facility capacity (proposed): 250 TJ/d	Waitsia (tCO2-e/year) Facility capacity: 250 TJ/d	West Erregulla (tCO2-e/year) Facility capacity: 87 TJ/d	MinRes remarks
				Once again, the West Erregulla gas plant is not directly comparable to either the LGP or the Waitsia gas plant in this regard because the incinerator is combined with the heating medium system, and they require significant amounts of fuel gas for the regeneration of the Silica Gel beds[3] (whilst the silica gel beds negate the requirement for export compression, they require frequent regeneration using hot, dry, pipeline quality gas which is then combusted, with associated emissions captured in this category).
Onsite power generation emissions	49,833	15,100	6,076	The LGP onsite power generation has significantly higher emissions than the Waitsia and West Erregulla gas plants due to the export compressor, recycle compressor and (future) inlet compressor having electric motor drives vs gas engine driven reciprocating compressors. The total for the Waitsia gas plant onsite power generation and export gas compression emissions is 42,900 tCO2-e/year compared to the LGP 49,833 tCO2-e/year for onsite power generation.
Flare – purge emissions	1,445	440	39	A conservative value is assumed for the LGP purge gas, noting the design maturity means the flare system is not definitively sized.
Flare – pilot emissions	882	60	-	A conservative value is assumed for the LGP pilot gas, noting the design maturity means the flare system is not definitively sized.
Flare - relief / blowdown emissions	152	330	208	
Flare - other (including pigging vents, compressor seal gas) emissions	363	-	492	

CO_2 emission source	Lockyer (tCO2-e/year) Facility capacity (proposed): 250 TJ/d	Waitsia (tCO2-e/year) Facility capacity: 250 TJ/d	West Erregulla (tCO2-e/year) Facility capacity: 87 TJ/d	MinRes remarks
Demineralised water tank (blanket) emissions	-	260	-	The LGP tank blanketing uses Nitrogen gas (N_2), no associated CO_2 emissions.
Condensate storage tanks (blanket) emissions	-	120	-	The LGP tank blanketing uses N_2, no associated CO_2 emissions.
Condensate loading package emissios	206	210	-	
Produced water evaporation pond emissions	-	180	-	For the LGP, 110 tCO2-e/year of 'fugitive emissions' is included in produced water.
Liquid circuit atmospheric vents emissions	-	-	71	
Fugitive emissions	2,553	-	172 (pipeline only)	The LGP fugitive emissions comprise facility and pipelines equipment according to Method 2 from the *National Greenhouse and Energy Reporting (Measurement) Determination*. This includes wellheads, gathering system pipelines, export pipeline, produced water system, and compressors included in the overall facility design.
Design margin emissions	-	3,900	-	
Summary				
Total emissions (tCO2-e/year)	78,198	~300,000	96,319	
Emissions intensity (tCO2-e/TJ)	0.88 (355 operating days)	3.29 (365 operating days)	3.03 (365 operating days)	

[1]Waitsia Gas Project Stage 2 Greenhouse Gas Management Plan
https://www.epa.wa.gov.au/sites/default/files/PER_documentation2/Greenhouse%20Gas%20Management%20Plan.pdf

[2]West Erregulla Processing Plant and Pipeline Greenhouse Gas Environmental Management Plan
https://www.epa.wa.gov.au/sites/default/files/Proponent_response_to_submissions/ERD%20Appendix%20I%20-%20Greenhouse%20Gas%20Management%20Plan%20-%20Rev%204.pdf

[3]West Erregulla Processing Plant and Pipeline Construction Environmental Management Plan
https://www.epa.wa.gov.au/sites/default/files/PER_documentation2/West%20Erregulla%20Construction%20Environmental%20Management%20Plan%20Rev%201.pdf

APPENDIX C

LOCKYER GAS DEVELOPMENT PROJECT: GREENHOUSE GAS ASSESSMENT TECHNICAL REPORT V1.3 (GREENBASE 2024)

LOCKYER GAS DEVELOPMENT PROJECT

GREENHOUSE GAS ASSESSMENT TECHNICAL REPORT

Version 1.3

Prepared by **Greenbase Pty Ltd**

On behalf of **Mineral Resources Limited**

Prepared April 2024

Disclaimer

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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.

Prepared by:

Greenbase Pty Ltd

Level 2, 41 St Georges Terrace, Perth WA 6000

PO Box Z5451, St Georges Terrace WA 6831

Telephone 08 9322 9966

Website www.greenbase.com.au

Table 1 Document History

Ver.	Date Completed	Details	Name	Status
1.3	05/04/2024	Corrected unit for emission intensity	Greenbase (H.Ko)	Final v1.3
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
	4/01/2024	Reviewed and provided feedback	MinRes	
1.0	13/12/2023	First version	Greenbase (H.Ko)	Final v1.0
0.2	08/12/2023	Greenbase internal review	Greenbase (J.Cole)	Draft
0.1	04/12/2023	Initial document prepared	Greenbase (H.Ko)	Draft

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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/terajoule (TJ) 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.

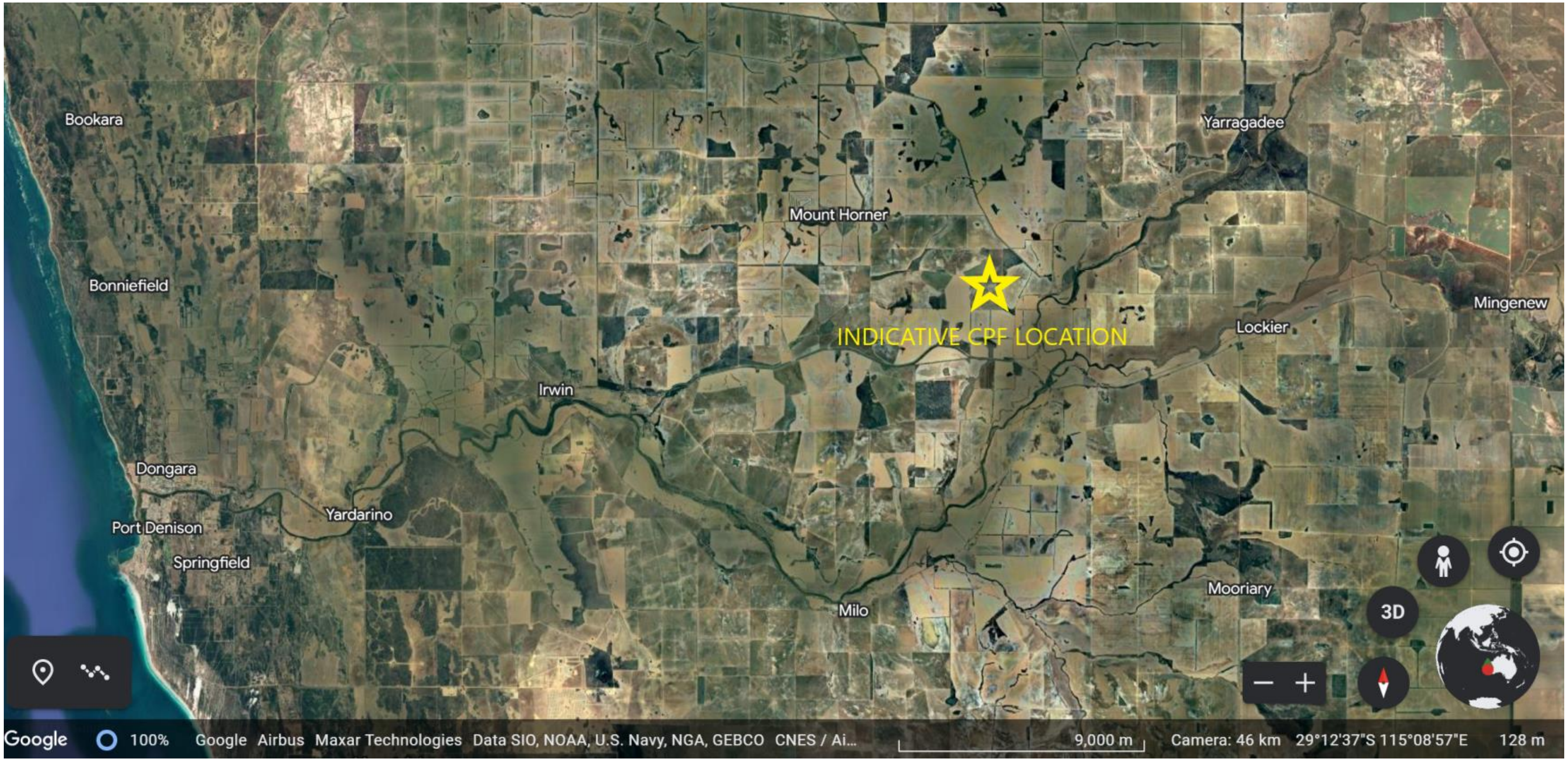


Figure 1 Indicative CPF location (Source: MinRes)

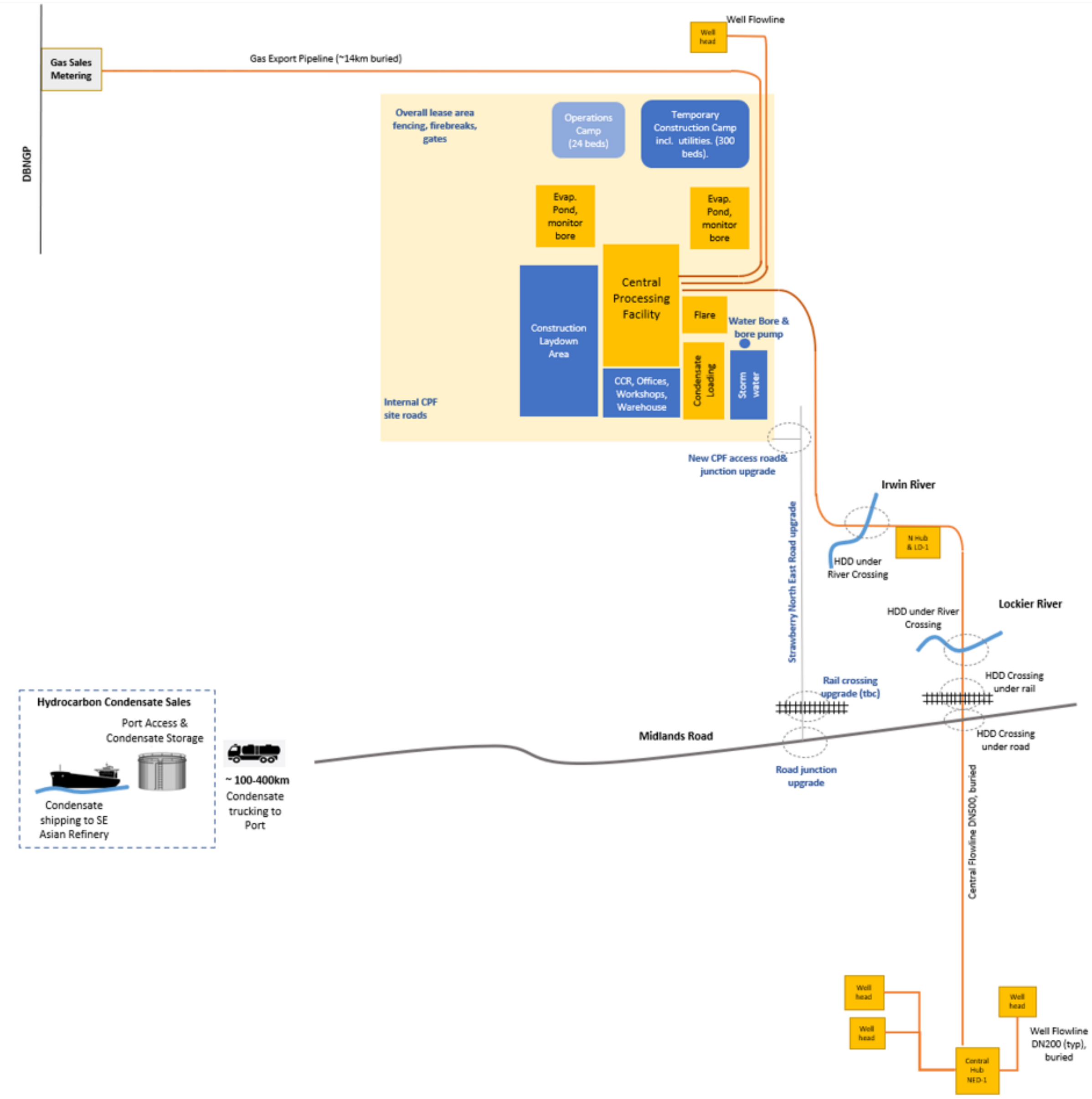


Figure 2 Project Process Diagram (Source: MinRes)

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**

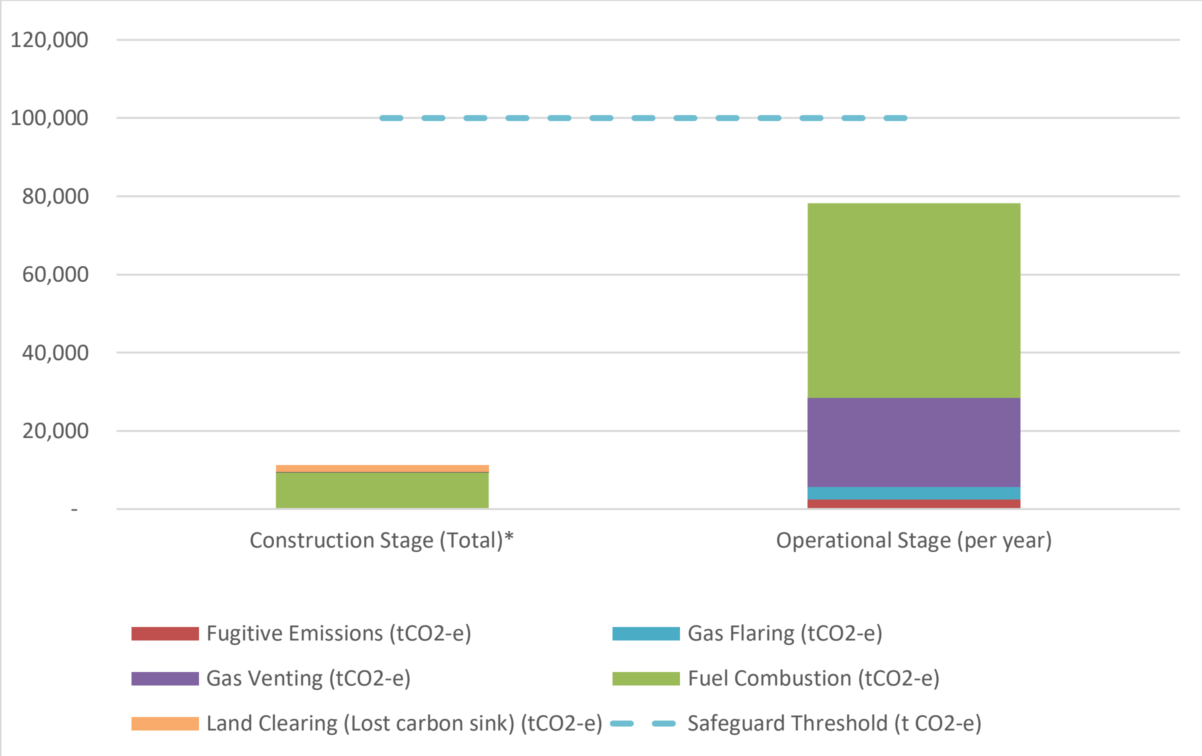
Total Scope 1 GHG Emissions

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/TJ 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		*= 6e*
1e	Energy consumption	14,342,814	GJ/ year		*= 8f*
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		*= 32e*
1j	Diesel Combustion (Electricity)	113	tCO2-e/year		*= 33e*
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/TJ gas produce		*= 1a ÷ (12d x 1,000)*

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

Appendix C References

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APPENDIX D
MINRES
PRESENTATION TO
THE YSRC CULTURAL
COMMITTEE

APPENDIX E
MINRES BRIEFING PAPER PROVIDED TO THE YSRC

APPENDIX F

YSRC LETTER OF SUPPORT FOR THE MINRES LOCKYER GAS PROJECT

APPENDIX G
LOCKYER
A. NUNAGINENSIS
MEMO (ELA 2024)

MEMORANDUM			
TO	Adam Parker and Alastair Trolove, Mineral Resources		
FROM	Rebecca Ovens and Rebecca Hide, Eco Logical Australia		
DATE	10 April 2024	PURPOSE	For Information
SUBJECT	Further information – No change to conservation status of Priority 3 flora species *Austrostipa nunaginensis*		

BACKGROUND

Energy Resources Limited, a wholly owned subsidiary of Mineral Resources Limited (MinRes), referred the Lockyer Conventional Gas Project (the Proposal; EPA reference APP-0025169) to the Department of Water and Environmental Regulation (DWER) on 5 March 2024 under Part IV section 38 of the *Environmental Protection Act 1986* (EP Act). The Proposal will collect natural gas from conventional wellheads and direct it via gas collection hubs to a Central Processing Facility (CPF) where the gas will be treated prior to export to the Dampier to Bunbury Natural Gas Pipeline.

On 4 April 2024, the Environmental Protection Authority (EPA) issued a Notice Requiring Further Information to MinRes. This notice requested further information on various matters, including the Priority 3 flora species *Austrostipa nunaginensis*. Specifically, the EPA requested:

- A brief justification that there is unlikely to be a change to the conservation status of *A. nunaginensis* (Priority 3 species) as a result of the proposed clearing activities.

This memorandum provides the required information on *A. nunaginensis*.

SPECIES DESCRIPTION AND DISTRIBUTION

A. nunaginensis is a perennial tussock grass species described in 2022 (Williams 2022). It was previously known by the name *Austrostipa* sp. Cairn Hill (M.E. Trudgen 21176) and was first collected in 1913 from the town of Nunagin (now Bruce Rock).

This species grows 20–50 cm tall and flowers in late spring, with fruiting in early summer. It occurs in the Geraldton Sandplains, Avon Wheatbelt and Swan Coastal Plain bioregions (Williams 2022). The Western Australian Herbarium (WAH) has recorded 11 populations from Geraldton in the north to Bruce Rock in the southeast (WAH 1998-2024), a range of approximately 445 km. The number of individuals recorded within these populations is unknown, although one population was recorded as 'locally common' (Department of Biodiversity, Conservation and Attractions (DBCA) 2024). At least one population was within a pasture paddock, and three populations were within reserves (Burma Road Nature Reserve, Cairn Hill Westrail Reserve, Yardanogo Nature Reserve).

In addition to the above records, two surveys (Phoenix 2023; JBS&G 2024) undertaken for the Proposal (within a 194.4 ha 'Survey Area') observed in excess of 19,000 individuals of *A. nunaginensis*. Less than 7,000 individuals were estimated to occur within the Proposal's Development Envelope and indicative

Disturbance Footprint. These individuals occurred within areas identified as being in a Degraded or Completely Degraded condition, and predominantly within the cleared paddock and Tagasaste plantation where the CPF is proposed to be constructed. It is noted that due to the high density of the plants, their numbers could only be estimated during the baseline surveys (Phoenix 2023; JBS&G 2024) and thus the population is likely to be greater than currently stated both inside and outside of the Development Envelope.

DISCUSSION OF *A. NUNAGINENSIS* CONSERVATION STATUS

Flora species that may possibly be threatened species that do not meet the criteria for listing under the *Biodiversity Conservation Act 2016* because of insufficient survey or are otherwise data deficient, are added to the Priority Flora Lists by DBCA under Priorities 1, 2 or 3. These three categories are ranked in order of prioritisation for survey and evaluation of conservation status so that consideration can be given to potential listing as threatened. Species that are adequately known, meet criteria for near threatened, or are rare but not threatened, or that have been recently removed from the threatened species list for other than taxonomic reasons, are placed in Priority 4.

A. nunaginensis is listed as a Priority 3 species by DBCA. Priority 3 species are described as:

- taxa that are known from several locations and the species does not appear to be under imminent threat; or
- taxa from few but widespread locations with either large population size or significant remaining areas of apparently suitable habitat, much of it not under imminent threat; or
- comparatively well-known from several locations but do not meet adequacy of survey requirements, and known threatening processes exist that could affect them. These species need further survey.

The Proposal is considered unlikely to change the conservation status of *A. nunaginensis* to Priority 2 or higher. An assessment (**Table 1**) against the Priority 2 criteria was undertaken considering the potential impacts of the Proposal on *A. nunaginensis* and justifying why the classification criteria do not apply in this scenario.

Table 1: Assessment of the Priority 2 criteria for *A. nunaginensis*

Priority 2 Criteria	Justification
Taxa that are known from one or a few locations (generally five or less), some of which are on lands managed primarily for nature conservation, for example, national parks, conservation parks, nature reserves and other lands with secure tenure being managed for conservation; or	Vegetation clearing for the Proposal will not remove an entire population of *A. nunaginensis.* This assumes that the more than 19,000 individuals estimated to occur within the Survey Area are considered a single population and the clearing of less than 7,000 individuals for the Proposal represents less than 37% of the individuals estimated to occur within this single population. The Proposal will also not impact the other 11 known populations of this species (DBCA 2024). *A. nunaginensis* will therefore continue to persist in at least 12 known populations, two of which are within lands managed primarily for nature conservation (Burma Road Nature Reserve and Yardanogo Nature Reserve). On this basis, *A. nunaginensis* is considered unlikely to meet the Priority 2 criteria of being known from one or a few locations.
Comparatively well-known from one or more locations but do not meet adequacy of survey requirements for threatened listing and appear to be under	The clearing of *A. nunaginensis* individuals due to the Proposal is considered unlikely to cause the taxa to meet this classification criteria for a Priority 2 species, as there is no evidence that the other 11 known populations of this species appear to be under threat from known threatening processes. The Proposal will also not

Priority 2 Criteria	Justification
threat from known threatening processes. These species are in urgent need of further survey.	increase the level of threat from threatening processes at the 11 other known populations of *A. nunaginensis*. Furthermore, the habitat descriptions from the 11 records (DBCA 2024) of this perennial tussock grass species indicate it may be a generalist, with habitats ranging from soaks, stoney hills and slopes, a seasonally damp valley bottom, slopes of low hills, and flats, with white, grey, yellow or brown sandy, clay or loamy soils. Vegetation structure in these areas has ranged from woodlands, shrublands, heath and grasslands (pasture), with varying species. In addition, the presence of *A. nunaginensis* in high numbers throughout the plantation and paddocks within the Development Envelope suggest it may also thrive in disturbed areas. This is supported by another record within paddocks located near Gingin (DBCA 2024). These traits increase the resilience and persistence of this species and reduce the likelihood of its conservation status being upgraded.

CONCLUSION

Based on the information provided in **Table 1**, the Proposal is considered unlikely to change the conservation status of *A. nunaginensis* (i.e. increase it to Priority 2 or higher) as a result of the proposed clearing activities.

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