Kauri Renewable Gas Project – Business Case

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Contents

Tables

Figures

Boxes

Executive Summary

Context

Currently, natural gas is exclusively transported in the Jemena Gas Network (JGN)[1] and the associated carbon emissions limit JGN and its customers from being able to meet their respective ESG commitments and other specific carbon emissions goals. This includes the NSW Government's objective for a 50% reduction in emissions by 2030 compared to 2005 levels.[2]

JGN is seeking to act on opportunities to meet customer and community expectations including to support greenhouse gas emissions reductions, promote a more efficient and resilient gas supply system and avoid unnecessary pressure on the electricity system infrastructure.

This includes evaluating potential investments that facilitate the supply of renewable gas to customers by providing renewable gas suppliers with access to the JGN. This is in line with recent amendments to the National Gas Rules (NGR) that align with government policy expectations that were recommended by the AEMC to:

- extend the regulatory framework to "enable the natural gas sector to evolve to using hydrogen and renewable gas to support Australia's emissions reduction plans."[3]
- incorporate the economic value of changes to Australia's greenhouse gas emissions, regardless of whether or not the economic value accrues directly or indirectly, or to the service provider, producers, users or end use as per Rule 79(4), in the assessment of the overall economic value of new capital expenditure under Rule 79(2)(a).[4] This economic value is to be calculated using the AER guidelines[5] on the value of emissions reduction (VER).

JGN has considered a range of measures or response options that might support customer and community expectations to manage the emissions from the supply and consumption of natural gas by customers.[6]

JGN is proposing to connect eight renewable gas projects to enable 8 PJ of biomethane to be injected into the network by 2030.

1 With the exception of the biomethane produced from the Malabar demonstration plant and the hydrogen injected blended from the Western Sydney Hydrogen Hub.

2 NSW Government, *NSW Climate and Energy Action: Reaching net zero emissions*, accessed 4 January 2024, https://www.energy.nsw.gov.au/nsw-plans-and-progress/government-strategies-and-frameworks/reaching-net-zero-emissions

3 AEMC (2022), *Review into extending the regulatory frameworks to hydrogen and renewable gases, Final rules report, 24 November 2022*, p. i.

4 AEMC (2024), *National Gas Amendment (Harmonising the national energy rules with the updated national energy objectives) Rule 2024*, https://www.aemc.gov.au/sites/default/files/2024-01/national_gas_amendment_harmonising_the_national_energy_rules_with_the_updated_national_energy_objectives_rule_2024_no.1.pdf

5 AER (2024), *Valuing emissions reduction AER draft guidance*, *March 2024*; https://www.aer.gov.au/system/files/2024-03/AER%20-%20Valuing%20emissions%20reduction%20draft%20guidance%20-%20March%202024.pdf

6 These response options include leakage management, customer demand management and direct emissions offset as mechanisms to manage the emissions from consumption of natural gas. It also considered a delayed connection option that would facilitate renewable gas connection to the JGN after the 2025-2030 AA period. However, these response options did not address all of the JGN objectives. For example, JGN customers have indicated that reducing emissions via offsets is not their preference as its not seen as 'genuine action'. Further detail is in the JGN 2025-30 Access Arrangement Proposal: *Emissions Reduction Program.*

This business case is focused on the merits of expenditure to connect the **Kauri Renewable Gas Project** at the [redacted] within JGN's 2025-2030 Access Arrangement period.

The [redacted] in close proximity to the JGN and has the potential to inject biomethane into the network [redacted] It is estimated that the [redacted]

Feasibility work on pipeline capex (including the connection cost and new pipeline cost categories) has been conducted by JGN to inform forecast expenditure.

Scope and objective of the business case

The objective of this Business Case is to demonstrate the expenditure from investment in the **Kauri Renewable Gas Project** proposed in JGN's 2025-30 Access Arrangement (as part of an ongoing program of investment in renewable gas):

- conforms with the new capital expenditure criteria set out in Rule 79(1) of the National Gas Rules;
- is justified under Rule 79(2)(a) of the National Gas Rules as the overall economic value is positive (NPV>0; BCR>1), calculated in accordance with Rule 79(3), and is justified under Rule 79(2)(c)(v) as the investment is necessary to meeting emissions reduction targets through the supply of pipeline services;
- aligns with JGN's customers' preferences, stakeholders' interests and broader Australian and NSW Government policy related to carbon emissions, bioenergy and renewable gas;
- aligns to broader regulatory guidance by the AER and other economic regulators in Australia related to funding of projects that promote resilience in the supply of services.

The cost-benefit analysis in this business case has estimated the economic value, in monetary terms, of the economic benefits and costs accruing to **JGN (as service provider), gas producers, users and end users** including the economic value of changes to Australia's greenhouse gas emissions calculated in accordance with Rule 79(3).

Consistent with standard CBA, all economic costs and benefits are assessed as *incremental* to a Base Case, which for this project involves comparison to a 'no investment in renewable gas' Base Case[7].

The approach to the CBA is:

- Consistent with the broad principles and techniques in standard CBA guidelines, whereby CBA uses forward-looking resource costs:
  - where a direct causal link (i.e. causal relationships between initiatives and outcomes) can be established between the project option and changes in 'real resource' outcomes;
  - outcomes are measured from the point of view of the economic value of the costs and benefits received by **JGN (as service provider), gas producers, users and end users** rather than simply the financial costs and benefits from the perspective of the renewable gas proponent (for example, we have accounted for the economic value of avoided

[7] Both JGN Pipeline expenditure (including the connection cost and new pipeline costs) and renewable gas Plant costs are complementary investments – both are required to enable the production and distribution of renewable gas to our customers. If the AER does not approve JGN expenditure, and JGN does not proceed with the investment, it is very unlikely gas supply will occur at these sites given renewable gas plant proponents are unlikely to source sufficiently directly connected customers to justify their investments.

greenhouse gas using the AER's VER[8]). The CBA does not incorporate any other market benefits which cannot be measured as an economic value accruing to JGN (as service provider), gas producers, users and end users, nor any transfers between consumers and producers[9], consistent with the AER's Cost-benefit analysis ISP guidelines[10].

- Utilising where possible, a set of plausible and verifiable publicly available information (including on the value of emissions reduction) consistent with the core valuation principle that goods and services are valued at the dollar amounts that individuals are willing to pay for them;
- Providing a transparent summary:
  - of the methodologies used to estimate the economic value, in monetary terms, of the costs and benefits accruing to JGN (as service provider), gas producers, users and end users; and
  - of any other costs and benefits, in qualitative terms, for which an economic value was not estimated and not incorporated in the CBA;
- Undertaking sensitivity analysis on key assumptions to understand the impact of uncertainty over the 30-year modelling period[11] on the overall economic value of the projects.

Findings of options analysis

- As summarised in **See Appendix B** for more detail on the methodologies used to estimate the economic value, in monetary terms, of the costs and benefits in the CBA. The qualitative assessment of the non-monetised impacts (see **Table 10**) is in addition to the estimated economic value in monetary terms.

Table 1**,** our analysis shows that the Project Option (Option 1) provides a net positive economic value relative to the 'no investment in renewable gas' (Base Case) in that the estimate of the economic value of the incremental benefits outweigh the incremental costs (in net present value terms). **That is, it has a positive economic value, and for this reason, it is justified under Rule 79(2)(a) of the NGR.**

The results of the economic analysis show Option 1 (Preferred Option) with:

- **Net Present Value (NPV)** of $114.40m ($FY2024, NPV) (discounted at 2.49%) compared to the Base Case. This means that investment in the Kauri Renewable Gas Project provides a net increase in economic value of $114.40m ($FY2024, NPV).[12]
- **Benefit Cost Ratio (BCR)** of 1.82 compared to the Base Case. This means that for every $1 of incremental cost incurred in the Kauri Renewable Gas Project there is an increase in economic benefit of $1.82.

These results are driven by the:

- **Benefits** ($254.24m ($FY2024, PV) in present value terms over the modelling period) that accrue to JGN (as service provider), gas producers, users and end users from:

8 Rather than the revenue stream that renewable gas suppliers may receive from the sale of ACCUs.

9 Transfers on their own do not result in resource costs or benefits.

10 AER (2023), *Cost benefit analysis guidelines*, *Guidelines to make the Integrated System Plan actionable*, p. 27, https://www.aer.gov.au/system/files/2023-10/AER%20-%20CBA%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf

11 The modelling period for the CBA is FY 2023-24 to FY 2052-53. A modelling period of 20-30 years, supported by terminal values to reflect the option's expected cost and benefits over the remaining years (i.e. beyond the modelling period) of its economic life is consistent with standard CBA guidelines, including the AER's Cost-benefit analysis ISP guidelines.

12 NPV is the preferred metric to rank investments under the National Electricity Rules (NER clause 5.15A.1(c)), reflected in the AER's Cost-benefit analysis ISP guidelines.

- more efficient gas supply services valued at the avoided costs of gas production and transmission ([redacted] ($FY2024, PV));
- more resilient gas supply services valued at the avoided costs of a gas shortfall [redacted] ($FY2024, PV));
- economic value of changes to Australia's greenhouse gas emissions from the displacement of natural gas consumption ([redacted] ($FY2024, PV)), monetised using the AER published VER;
- residual value of the Plant and Pipeline ([redacted] ($FY2024, PV));

outweighing the

- **Costs** [redacted] ($FY2024, PV) over the modelling period) that accrue to service to JGN (as service provider), gas producers, users and end users from:
  - JGN pipeline capex ([redacted] ($FY2024, PV));
  - Plant capex[13] ([redacted] ($FY2024, PV));
  - Plant opex ([redacted] ($FY2024, PV));
  - Foregone use of biogas for other purposes ($24.71m ($FY2024, PV)).

See **Appendix B** for more detail on the methodologies used to estimate the economic value, in monetary terms, of the costs and benefits in the CBA. The qualitative assessment of the non-monetised impacts (see **Table 10**) is in addition to the estimated economic value in monetary terms.

[13] The Plant costs are complementary to JGN Pipeline capex. Costs are incurred on both assets to enable the production and distribution of renewable gas to customers.

Table 1: Summary of cost-benefit analysis ($m, $FY2024, PV)

	Project Option 1 (incremental to the Base Case) ($m, $FY2024, PV)
Benefits	
Residual value of plant and pipeline capital costs	[redacted]
More efficient gas supply services – avoided natural gas production and transmission costs	
Economic value of changes to Australia's greenhouse gas emissions – avoided GHG emissions	
Increase gas supply resilience – avoided costs of a gas shortfall	
Total benefits	**254.24**
Costs	
Plant capex	[redacted]
Pipeline capex	
Plant opex	
Foregone use of biogas for other purposes	
Total costs	
Net present value	**114.40**
Benefit cost ratio	**1.82**

Source: Frontier Economics

Consistent with standard practice, we have undertaken additional sensitivity analysis covering key assumptions including forecast capex and opex, forecast domestic gas prices, levels of renewable gas production from the site, the economic value of emissions reduction, likelihood of gas supply shortfalls and discount rates for the preferred Project Option (Option 1).

As summarised in **Table 2*, the estimated present value of the benefits outweighs the costs (i.e. a net positive economic value) under each sensitivity scenario. This demonstrates the economic value of Option 1 is resilient to key uncertainties.***

Table 2: Individual sensitivity analysis for Option 1

Sensitivity scenario	Sensitivity value	Net present value ($m, $FY2024)	Benefit cost ratio
Capex and opex			
Low	+20%	[redacted]	
Central	JGN estimates		
High	-20%		
Value of emissions reduction			
Low	VER (-25%): $52.50 in 2024 ($FY2023), escalated by CPI+~7%	82.43	1.59
Central	VER: $70.00 in 2024 ($FY2023), escalated by CPI+~7%	114.40	1.82
High	VER (+25%): $87.50 in 2024 ($FY2023), escalated by CPI+~7%	146.37	2.05
Domestic gas price[14]			
Low	-22% ($8.64/GJ)	88.37	1.63
Central	$11.07/GJ	114.40	1.82
High	+76% ($19.48/GJ)	206.00	2.47
Probability of supply shortfall (each year from 2025)			
Low	0.014%	[redacted]	
Central	0.137%		
High	0.274%		
Renewable feedstock volumes[15]			
Low	-20%		
Central	JGN estimates		
High	+20%		
Renewable gas production efficiency[16]			

[14] Prices are the average prices over the 30-year period in $FY2024.

[15] This sensitivity tests the uncertainty of input feedstock volumes and its corresponding impact to plant operating costs and gas production volumes.

[16] This sensitivity tests the uncertainty of the technology to convert feedstock into biomethane where the inputs and costs remain fixed, but the biomethane production and injection volumes and its corresponding benefits vary.

Sensitivity scenario	Sensitivity value	Net present value ($m, $FY2024)	Benefit cost ratio
Low	-20%	[redacted]	
Central	JGN estimates		
High	+20%		

Source: Frontier Economics

Consistent with standard practice, we have also analysed the distribution of these costs and benefits to demonstrate who will be impacted.

Given that in many markets the costs are ultimately shared between parties on the basis of impactor and/or beneficiary pays outcomes, considering the *ultimate* incidence of the costs is consistent with best practice distributional analysis. By breaking down the impact by stakeholder, we gain a clearer understanding of who will *ultimately* incur the costs and receive the benefits of the project.

While each of these cost categories will be funded by different stakeholders, we have assumed that all capital and operating costs associated with the project will *ultimately* be passed through to gas users directly via JGN network tariffs and/or via gas supply & transport contracts paid for gas supply.[17]

This analysis shows that the economic value of the costs and benefits that have been monetised in the CBA (i.e. excluding costs and benefits set out in the qualitative analysis) are primarily borne or received by **gas users**, and ***results in gas users (as a whole) being significantly 'better off' in that the benefits received by gas users exceed the costs they ultimately incur.*** The benefits include more efficient gas supply services (in the form of avoided costs), increased gas supply resilience, an economic value of changes to Australia's greenhouse gas emissions (in the form of avoided GHG emissions), and the ongoing value of plant and pipeline capital assets to supply renewable gas to customers beyond the modelling period.

17 Given gas producers will seek to recover their costs through charges they negotiate with gas shippers / retailers for the supply of renewable gas.

Conclusions and recommendations

Based on the analysis in this business case we conclude that investment (Option 1) in the **Kauri Renewable Gas Project**:

- Is justified under Rule 79(2)(a) of the National Gas Rules as the overall economic value is positive (NPV>0; BCR>1), calculated in accordance with Rule 79(3), and is justified under Rule 79(2)(c)(v) as the investment is necessary to meeting emissions reduction targets through the supply of pipeline services;
- Aligns with JGN's customers' preferences, stakeholders' interests and broader Australian Government and NSW Government policy including NSW Government Net Zero Plan to "drive uptake of proven emissions reduction technologies";[18]
- Results in gas users (as a whole) being significantly 'better off' in that the benefits received by gas users exceed the costs they ultimately incur. This includes more efficient gas supply services, increased gas supply resilience, an economic value of changes to Australia's greenhouse gas emissions (in the form of avoided GHG emissions), and the ongoing value of plant and pipeline capital assets to provide renewable gas to customers beyond the modelling period.
- Aligns to broader regulatory guidance by the AER and other economic regulators in Australia related to funding of projects that promote resilience in the supply of services.

If the AER does not approve this JGN expenditure, it is unlikely JGN will proceed with this investment, which means renewable gas supply will not occur at this site. This is because it is unlikely that renewable gas supply proponents would be able to source sufficiently directly-connected gas customers to justify their investments. This means that the estimated net positive economic value from the **Kauri Renewable Gas Project** – that is primarily received by gas users – will not be realised. In our view, this would not be in the long-term interest of customers and the amended NGO.

For this reason, we recommend:

- JGN invest in network infrastructure to provide renewable gas suppliers at the site with access to the JGN in turn enabling renewable gas supply to gas users (as a whole);
- AER allow JGN to recover the efficient costs of providing *reference services* (which is a proportion of the costs that JGN will incur to enable renewable gas supply to gas users) from its reference services charges via its 2025-2030 Access Arrangement.

[18] NSW Government *Department of Planning, Industry and Environment, Net Zero Plan Stage 1: 2020-2030*

1 Background and context

This section provides an overview of the context and background to this cost-benefit analysis (CBA) and business case.

1.1 Background

1.1.1 Background to JGN

JGN is the major gas distribution service provider in New South Wales (NSW). JGN owns around 25,000 kilometres of natural gas distribution assets, delivering approximately 90 petajoules of natural gas to over 1.5 million homes, businesses and large industrial consumers across NSW.

The energy system is in the midst of a fundamental transformation. Decarbonisation, propelled by consumer choice and enabled by policy and technological changes, will require the energy system of the future to be very different to the energy system of today.

JGN sees gas distribution networks playing a crucial role in tomorrow's energy system by:

1. Providing consumers and industry with an alternative decarbonisation pathway to assist in meeting Australia's emissions reduction objectives – that would enable customers to continue to utilise gas, particularly those customers that may find electrification challenging and/or costly.
2. Avoiding costly and uncertain upgrades to the electricity networks and generation fleet providing a lower cost whole of system decarbonisation pathway.
3. Supporting the decarbonisation of other sectors such as transport, and playing a role in energy storage and grid security.

However, this is not guaranteed, and JGN has been engaging closely with customers, stakeholders and industry to identify how best JGN can support these outcomes, including through facilitating the growth of the renewable gas sector where it is in the long-term interests of customers.

1.1.2 Background to renewable gas

The physical supply chain for the supply of natural gas to customers historically consists of the production of natural gas in large centralised facilities (which are located near to underground reserves of natural gas, which in most cases are long distances from customers), the transport of gas from production and storage facilities to local distribution networks using long-distance high-pressure transmission pipelines, and the local distribution of gas to customers. The natural gas sector in eastern Australia has faced challenging conditions in recent years, and is expected to continue to face challenging conditions in coming years, as discussed in **Box 1** and in **Figure 1.**

Renewable gas has the potential to change this supply chain with the potential to improve the resilience of both the gas and electricity sectors, support decarbonisation to assist in meeting Australia's emissions reduction objectives and promote and offer alternative pathways to market for producers of biogas from what was once considered waste resources.

Box 1: Challenges facing the natural gas sector in eastern Australia

The natural gas sector in eastern Australia faces twin challenges of ensuring adequate supply of gas to users, while at the same time supporting the energy transition.

Supply and demand

Supply and demand conditions in the gas sector in eastern Australia have changed dramatically over the last decade, primarily triggered by the commencement of LNG exports from three LNG facilities located at Gladstone. These exports resulted in gas demand in eastern Australia increasing almost three-fold, from roughly 700 PJ/a to roughly 1,900 PJ/a. At the same time, moratoria and regulatory restrictions on gas developments were introduced in several jurisdictions, affecting onshore gas exploration and development.

In its initial review of the East Coast Gas Market, the ACCC noted that "this brought increased uncertainty and complexity to the market, particularly for C+I users that had typically operated with long-term contracts of low-priced gas."[19]

Since its initial review of the East Coast Gas Market, the ACCC has continued to report on the potential for gas shortages. The ACCC reported that "[t]he latest information suggests that the east coast gas market is likely to have sufficient supply to meet energy needs throughout the transition until 2028". But "[i]n the longer-term, current expectations of gas demand through the energy transition will still require additional sources of gas supply. There will be gas shortfalls without the development of new gas fields, pipelines and potentially LNG import terminals or without a significant reduction in demand."[20]

One of the consequences of the tighter supply-demand balance in the gas market in eastern Australia since the commencement of LNG exports has been higher (LNG-linked) and more volatile wholesale gas prices. This price volatility reached its peak in 2022, leading to government intervention in the form of the Gas Market Emergency Price Order (capping the wholesale price at $12/GJ) followed by the new Gas Market Code (which limits wholesale prices from gas producers that are not exempt).

The gas sector will also be profoundly affected by commitments to reduce greenhouse gas emissions. Both AEMO and the ACCC, among others, recognise the role that natural gas is expected to have during the energy transition. For instance, the ACCC notes that "[g]as is expected to have a critical role over the next two decades to maintain power grid security, maintain supply to commercial and industrial customers, and support households as they electrify."[21]

Supporting the energy transition

Significant progress has been made in reducing the emissions intensity of electricity supply, driven in large part by renewable schemes (such as the LRET and SRES) and direct government investment, that have helped to subsidise the cost of renewable electricity. As a result, electricity customers have options for reducing the emissions associated with their use of electricity. The availability of options to reduce emissions associated with the use of electricity is an important driver of a push towards gas customers electrifying their gas use.

However, there are also options to reduce emissions from gas use, particularly for those customers such as some industrial gas customers where emissions reduction is challenging.

Until recently, gas customers in eastern Australia have not had access to options to directly reduce the emissions associated with their use of gas, in part as a result of the lack of policies to support investment in renewable gas. However, both in Australia and internationally there is increasing focus on sources of renewable gas – such as biomethane and hydrogen. A number of projects have come online in Australia in the last year or two. These renewable

19 ACCC (2017), *Gas Inquiry 2017–2020 Interim Report September 2017*, p. 13.

20 ACCC (2023), *Gas Inquiry 2017–2030 Interim update on east coast gas market December 2023*, p. 9.

21 ACCC (2023), *Gas Inquiry 2017–2030 Interim update on east coast gas market December 2023*, p. 9.

gases provide the opportunity for gas customers to reduce their emissions while continuing to use gas during the energy transition.

New sources of gas supply – particularly new sources of renewable gas supply – can play a clear role in addressing these challenges by increasing the supply of gas in eastern Australia, by increasing diversity in supply and by providing options for gas users to reduce the emissions associated with their use of gas.

Renewable gases are carbon neutral, meaning that they do not produce any additional emissions when burnt as fuel. In the context of gas networks, renewable gases typically refer to:

- Biomethane – gas that is derived from plant and animal by-products, agriculture, farming, forestry and human waste. Methane is captured, optimised and re-used, instead of being naturally released into the atmosphere from its original waste source, so there are no additional emissions in the production process. Biomethane is interchangeable with natural gas, and does not require significant changes to gas infrastructure or changeout of customer appliances.
- Renewable hydrogen - produced by separating hydrogen from water which is powered by electricity from renewable sources. When burnt, hydrogen produces no carbon emissions.

Renewable gases can displace natural gas when injected into the gas network, resulting in a reduction in overall carbon emissions across the supply chain. While renewable gases are still in their infancy in Australia, other countries are already making significant investments in renewable gases for use within gas networks. For example, biomethane is used widely in many countries, particularly in Europe. The European Union is targeting biomethane production of 35 billion cubic metres per year by 2030.[22] In Denmark in particular, biomethane supplied more than 39% of gas demand in 2022 and is projected to increase to more than 100% by 2030.[23]

JGN has also made investments to support the development of the renewable gas industry, and renewable gas is already being distributed to customers across its network as outlined in **Box 2**.

Box 2: JGN renewable gas investments

Interconnection of the Malabar Biomethane Injection Plant into JGN's network

The Malabar Biomethane Injection Plant is the first of its kind in Australia. In partnership with Sydney Water, the Malabar Biomethane Facility upgrades biogas produced from organic waste at the Malabar Water Resource Recovery Facility so that it is suitable for injection into JGN's gas network. The Malabar Biomethane Facility project is jointly funded by Jemena Malabar Pipeline Pty Ltd (JMP) and the Australian Renewable Energy Agency (ARENA) which is contributing up to $5.9 million in grant funding. The facility has an initial capacity of 95 terajoules (TJ) of renewable gas per annum. This is about equivalent to the average annual gas usage of 6,300 NSW homes.

During the current plan period, JGN entered into an interconnection agreement with JMP to enable this renewable gas to be injected into the network.

Western Sydney Hydrogen Hub

22 European Commission (2022), *REPowerEU Plan*. 35 billion cubic metres is approximately equal to 1,311 PJ.

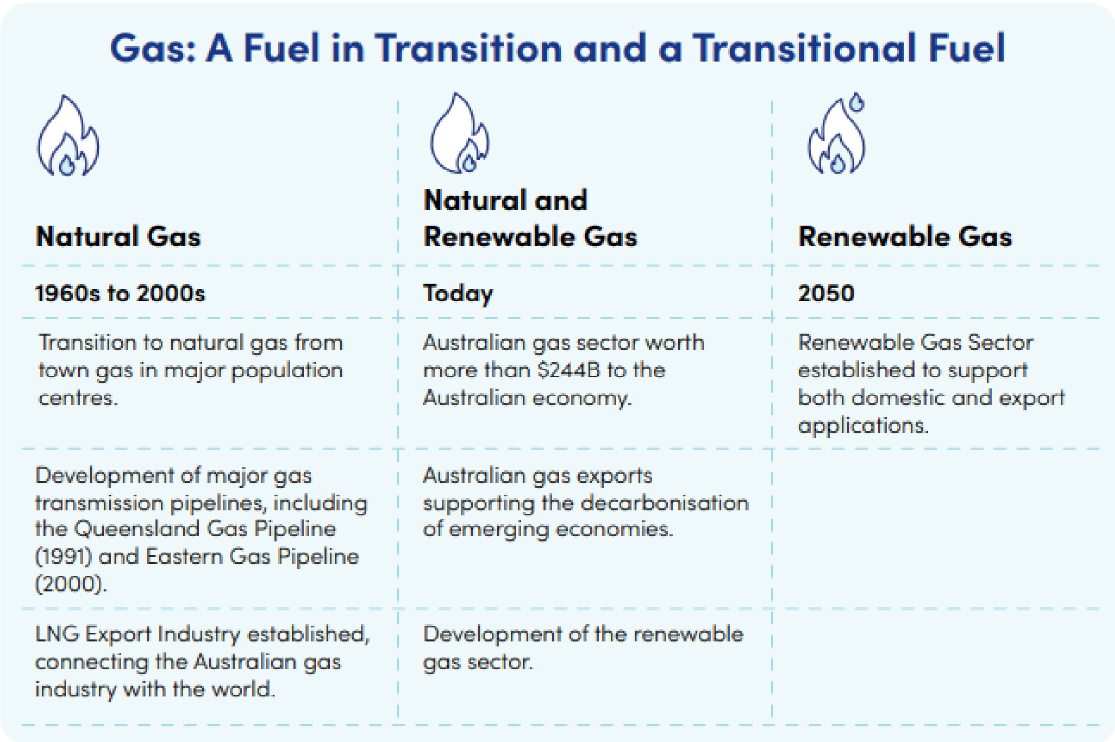
23 CE Delft (2022), *Biomethane: bridging for cooperation Between Denmark and the Netherlands*, https://cedelft.eu/wp-content/uploads/sites/2/2022/04/CE_Delft_210177_Biomethane_Bridging-for-cooperation_DEF.pdf

The Western Sydney Hydrogen Hub is a $15 million project and renewable gas trial, co-funded by JGN and the Australian Renewable Energy Agency (ARENA). The Western Sydney Hydrogen Hub demonstrates the effectiveness of hydrogen in helping to achieve emissions reduction targets in NSW.

Hydrogen is produced by a 500kW on-site electrolyser, which is powered by the electricity network and offset using certificates. Once injected into the existing gas network, and blended with natural gas, the hydrogen can be used by homes and businesses in the surrounding areas of Western Sydney.

Source: JGN

Figure 1: Changes in Australia's gas sector



Source: JGN (2021), 2021 SGSPAA Group Sustainability Report, p. 18.

1.1.3 Context

JGN is preparing for the review of its Access Arrangement (AA). The AA will cover the period from 1 July 2025 to 30 June 2030.

A key element in allowing JGN to facilitate the distribution of renewable gas to its customers is the AER's approval of renewable gas expenditure for the 2025-30 period.

JGN's AA Proposal will include expenditure to connect eight renewable gas sources, including:

- Lilli Pilli project: [redacted] that will generate biomethane gas for injection as renewable gas supply into the JGN;

- Kauri project (focus of this business case): [redacted] that will generate biomethane gas for injection as renewable gas supply into the JGN;
- Blue Gum project: Site in [redacted] that will utilise [redacted] as feedstock to generate biomethane gas for injection as renewable gas supply into the JGN;
- Red Gum project: Site in [redacted] that will utilise [redacted] as feedstock to generate biomethane gas for injection as renewable gas supply into the JGN;
- Iron Bark project: Site in [redacted] that will utilise [redacted] as feedstock to generate biomethane gas for injection as renewable gas supply into the JGN;
- Huon Pine project: Site in [redacted] that will utilise [redacted] as feedstock to as feedstock to generate biomethane gas for injection as renewable gas supply into the JGN;
- Coolabah project: Site in [redacted] that will utilise [redacted] as feedstock to generate biomethane gas for injection as renewable gas supply into the JGN;
- Wollemi project: Site in [redacted] that will utilise [redacted] as feedstock to generate biomethane gas for injection as renewable gas supply into the JGN.

For the JGN capital expenditure associated with these renewable gas projects to conform with the new capital expenditure criteria set out in Rule 79(1) of the National Gas Rules, these projects can be justified under Rule 79(2)(a) of the National Gas Rules, such that the overall economic value is positive (NPV>0; BCR>1), calculated in accordance with Rule 79(3).

1.1.4 Kauri Renewable Gas Project

[redacted] It is operated by [redacted] who produces biogas at the site as part of [redacted]

[redacted]

It is estimated that the landfill site can produce [redacted] per year of renewable gas. It is [redacted]

Feasibility work on pipeline capex (including the connection cost and new pipeline cost categories) has been conducted by JGN to inform forecast expenditure.

1.2 Regulatory requirements and guidance

This business case is guided by numerous regulatory requirements and guidance papers. It is primarily guided by the National Gas Rules and the *National Gas Amendment (Harmonising the national energy rules with the updated national energy objectives) Rule 2024* as this is the primary framework the AER must have regard to when assessing JGN's expenditure in their AA proposal. Supporting key guidance documents include the AEMC's release of the Ministerial Council on Energy

[redacted]

(MCE) interim methodology[25] and AER draft guidelines[26] on the value of emissions reduction (VER). However, there is also other CBA guidance that is relevant to identifying the option that maximises the present value of net economic benefit to service providers, gas producers, users and end users, including guidance from:

- the AER including the AER's cost-benefit analysis ISP guidelines[27];
- NSW Treasury[28] and other advisory bodies such as Infrastructure Australia[29].

Finally, other regulators in Australia including the AER have considered how to identify and incentivise utilities to invest in options that maximise the present value of net economic benefits, including market benefits that accrue to parties other than the service provider. This can include the benefits from the value of changes in greenhouse gas emissions as well as the value of improved network resilience in the supply of services.[30]

While this other CBA and regulatory guidance applies to other sectors, the key principles in these guidelines are relevant to this project.

Table 3 provides a brief overview of the primary NGR guidance, their relevance to this project and how we have used the guidance material in preparing the cost-benefit analysis and business case. An overview of how we have considered the other guidance can be found in **Appendix A**.

[25] AEMC (2024), *How the national energy objectives shape our decisions, Final guidelines, 28 March 2024;* https://www.aemc.gov.au/sites/default/files/2024-03/AEMC%20guide%20on%20how%20energy%20objectives%20shape%20our%20decisions%20clean%20200324.pdf;

[26] AER (2024), *Valuing emissions reduction AER draft guidance, March 2024*; https://www.aer.gov.au/system/files/2024-03/AER%20-%20Valuing%20emissions%20reduction%20draft%20guidance%20-%20March%202024.pdf

[27] AER (2023), *Cost benefit analysis guidelines, Guidelines to make the Integrated System Plan actionable,* https://www.aer.gov.au/system/files/2023-10/AER%20-%20CBA%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf

[28] NSW Treasury (2023), *TPG23-08 NSW Government Guide to Cost-Benefit Analysis*. https://www.treasury.nsw.gov.au/sites/default/files/2023-04/tpg23-08_nsw-government-guide-to-cost-benefit-analysis_202304.pdf

[29] Infrastructure Australia (2021), *Guide to economic appraisal* accessed 11 December 2023. https://www.infrastructureaustralia.gov.au/sites/default/files/2021-07/Assessment%20Framework%202021%20Guide%20to%20economic%20appraisal.pdf

[30] AER (2022), *Network resilience*, accessed 11 December 2023, https://www.aer.gov.au/system/files/Network%20resilience%20-%20note%20on%20key%20issues.pdf

Table 3: National Gas Rules regulatory requirements and guidance

Guidance description	Relevance to this project
NGR 79(1)(a), 79(1)(b) and 79(2)(a): (1) Conforming capital expenditure is capital expenditure that conforms with the following criteria: (a) the capital expenditure must be such as would be incurred by a prudent service provider acting efficiently, in accordance with accepted good industry practice, to achieve the lowest sustainable cost of providing services; and (b) the capital expenditure must be justifiable on a ground stated in subrule (2); (2) Capital expenditure is justifiable if: (a) the overall economic value of the expenditure is positive subject to subrule (3)	The cost-benefit analysis aims to justify the capital expenditure by showing that the overall economic value of the expenditure is positive.
NGR 79(3):[31] (3) In deciding whether the overall economic value of capital expenditure is positive, consider the sum of: (a) the economic value, other than of changes to Australia's greenhouse gas emissions, directly accruing to the service provider, producers, users and end users; and (b) the economic value of changes to Australia's greenhouse gas emissions, whether or not that value accrues (directly or indirectly) to the service provider, producers, users or end users.	The cost-benefit analysis incorporates an estimate of the economic value accruing to JGN, gas producers, users and end users, including the economic value of changes to Australia's greenhouse gas emissions
Interim Value of Emissions Reduction (VER) methodology:[32] The VER is the 2022-23 average of the generic Australian Carbon Credit Unit spot price (AUD$33/tonne CO2-e) with a growth rate of 10% p.a. averaged with a linear interpolation of: 1. From 2024-2029: the IPCC Fifth Assessment Report Representative Concentration Pathway 2.6 (commonly referred to as RCP2.6) scenario, median marginal cost of abatement figures, converted into 2023 AUD dollars. 2. From 2030-2050: the IPCC Sixth Assessment Report Category 2 (commonly referred to as C2) emissions scenario median marginal cost of abatement figures, converted into 2023 AUD dollars. Beyond 2050, the 2050 value should apply. Undertake sensitivity analysis using values up to 25% higher or lower than the VER.	The estimated economic value of changes to Australia's greenhouse gas emissions, including sensitivity scenarios, is developed in line with the interim VER guidance.

Source: Frontier Economics

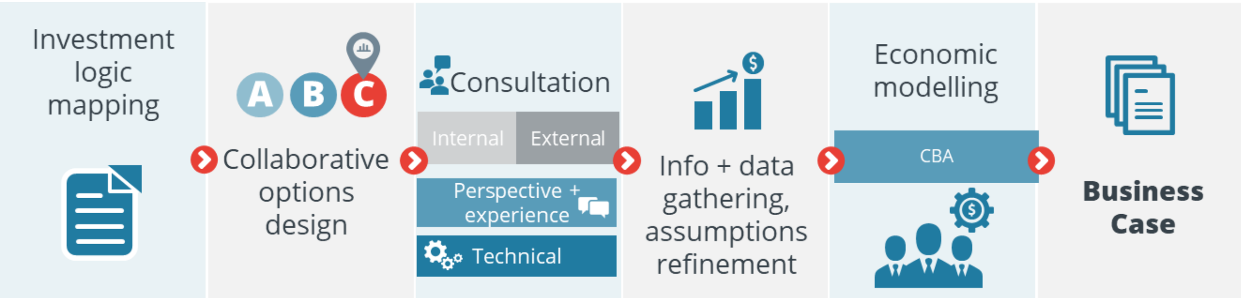
1.3 Scope of this Business Case

JGN engaged Frontier Economics to develop this business case consistent with the requirements of the NGR, as well as have regard to other relevant AER and regulatory guidance related to business case development and CBA.

This includes the following steps and is depicted in **Figure 2**:

- Understanding and establishing the problem definition, case for change and what would occur in the absence of JGN investment;
- Preparing and delivering an Investment Logic Map including conducting workshops to capture benefits and inputs;
- Defining and establishing the base case;
- Developing a set of strategic response options and then project options to be subject to cost-benefit analysis;
- Applying an economic CBA framework to assessing the economic value that accrues to the defined reference group: service providers, gas producers, users and end users[33], as per Rule 79(3) – further detail in section below;
- Summarising and developing the cost-benefit analysis into a long form business case that meets the AER requirements.

Figure 2: Business Case Process



Source: Frontier Economics

[31] AEMC (2024), *National Gas Amendment (Harmonising the national energy rules with the updated national energy objectives) Rule 2024*, https://www.aemc.gov.au/sites/default/files/2024-01/national_gas_amendment_harmonising_the_national_energy_rules_with_the_updated_national_energy_objectives_rule_2024_no.1.pdf

[32] AEMC (2024), https://www.aemc.gov.au/news-centre/media-releases/aemc-updates-guidance-how-we-consider-emissions-our-decisions

[33] Similar to the clause 5.22.10(d) of the NER, AER's cost-benefit analysis ISP guidelines require the inclusion of any measured cost to generators, distribution network service providers (DNSPs), TNSPs and consumers, and market benefits to those who consume, produce and transport electricity in the market. AER (2023), *Cost benefit analysis guidelines*, *Guidelines to make the Integrated System Plan actionable*, pp. 24-26.

1.3.1 Overview of our approach to economic evaluation

Our approach to the **cost-benefit analysis (CBA)** aligns with the NGR as well as many of the broad principles and techniques in standard CBA guidelines, including the AER's cost-benefit analysis ISP guidelines[34]. This includes:

- **Step #1:** Developing an appropriate Base Case and alternative project option(s). The first step is to develop a Base Case and range of options. The Base Case and project options are set out in **Section 2.4** and the project options are set out in **Section 3.1**.
- **Step #2:** Identifying the economic value of the costs and benefits that accrue to a defined reference group: service providers, gas producers, users and end users[35], as per Rule 79(3)**.** We estimate the economic value of a range of outcomes that accrue to the reference group compared to the Base Case:
  - Using internally consistent and transparent input variables and parameters, while also accounting for uncertainty by creating "scenarios around the most likely scenario" [36];
  - Estimating the economic value (rather than financial value) of the costs and benefits over a long-term (30 years) modelling period[37], including the economic value of changes to Australia's greenhouse gas emissions using the AER's VER[38]. The approach to assessing each quantitative cost and benefit is set out in **Section 3.2** and further detailed in **Appendix B**;
  - Ensuring no double-counting of costs or benefits, and excluding any 'financial or wealth' transfer of value between consumers and producers[39].
  - In line with CBA guidance, impacts which cannot be valued have been excluded, and separately described qualitatively.
- **Step #3:** Comparing the present value of the incremental costs and benefits to calculate the net present value (NPV)[40] and benefit-cost ratio (BCR)[41] for the project relative to 'no investment in renewable gas' (Base Case). In particular:
  - **NPV>0 and BCR>1 indicates that the option results in a net economic benefit** relative to the Base Case (i.e. incremental benefits of the option exceed incremental costs).
  - **NPV = 0 or BCR = 1 indicates that the incremental benefit** of the option exactly equals its incremental costs.

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34 AER (2023), *Cost benefit analysis guidelines*, *Guidelines to make the Integrated System Plan actionable,* https://www.aer.gov.au/system/files/2023-10/AER%20-%20CBA%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf

35 Similar to the clause 5.22.10(d) of the NER, AER's cost-benefit analysis ISP guidelines require the inclusion of any measured cost to generators, distribution network service providers (DNSPs), TNSPs and consumers, and market benefits to those who consume, produce and transport electricity in the market. AER (2023), *Cost benefit analysis guidelines*, *Guidelines to make the Integrated System Plan actionable*, pp. 24-26.

36 AER (2023), *Cost benefit analysis guidelines, Guidelines to make the Integrated System Plan actionable*, p. 17.

37 Consistent with the AER's Cost-benefit analysis ISP guidelines, this involves the use of terminal values to reflect the option's expected cost and benefits over the remaining years (i.e. beyond the modelling period) of its economic life. AER (2023), *Cost benefit analysis guidelines, Guidelines to make the Integrated System Plan actionable*, p. 76.

38 Rather than the revenue stream that renewable gas suppliers may receive from the sale of ACCUs.

39 AER (2023), *Cost benefit analysis guidelines*, *Guidelines to make the Integrated System Plan actionable*, pp. 27, 43.

40 The difference between the present value of the costs and the present value of the benefits over the period.

41 The present value of benefits over the period divided by the present value of costs over the period.

  - **NPV < 0 and BCR < 1 indicates that the option results in a net economic cost** relative to the Base Case (i.e. incremental costs of the option exceed incremental benefits).

  The results of the CBA are set out in **Section 0**.

- **Steps #4:** Considering risk and uncertainty to identify the option that maximises the present value of net economic benefit to service providers, gas producers, users and end users (i.e. maximises NPV>0, compared to the 'no investment in renewable gas' (Base Case)).

There are important elements that distinguish a CBA from other related types of project analysis:

- It considers all relevant sources of economic value that accrue to the reference group including the economic value of emissions reductions that accrue indirectly to the reference group (directly or indirectly) as per the NGR and the *National Gas Amendment (Harmonising the national energy rules with the updated national energy objectives) Rule 2024*;
- It is based on the resource opportunity cost or benefit, which may differ from financial impacts or cash flows;
- All future costs and benefits are discounted using a discount rate appropriate for the analysis. For this CBA we have used a discount rate for private enterprise investment as required in the AER's guidance of cost-benefit analysis for the ISP.[42] This differs from standard CBA guidelines such as NSW Treasury or Infrastructure Australia (IA) framework of using a social discount rate. However, we have adopted a higher social discount rate as a sensitivity;
- To avoid potentially confusing efficiency and equity analysis, the CBA itself focuses on efficiency as per the NGR and does not include financial transfers, nor incorporate the distribution of these costs and benefits across market participants. It is standard practice for a business case to include distributional analysis as separate supplementary analysis to a CBA.

1.4 Structure of this report

The remainder of this report is structured as follows:

- **Section 2** provides an overview of the objective, problem and opportunities underpinning the investment and summarises the broad range of strategic response options identified to manage the emissions from consumption of natural gas and the opportunity with renewable gas.
- **Section 3** details the project options identified as the preferred strategic option, summarises the incremental economic, social and environmental costs and benefits included in our analysis and provides an overview of our approach to monetising key impacts.
- **Section 4** provides an overview of the results of our economic evaluation, including qualitative analysis, sensitivity & scenario analysis and distributional analysis.
- **Section 5** provides an overview of the distributional and funding analysis.
- **Section 6** describes the delivery case of the preferred project option.
- **Appendix A** provides an overview of other regulatory guidance that we have had regard to in the development of the business case.
- **Appendix B** provides a detailed description of the methodology, assumptions made in the valuation of the CBA and their sources.

42 AER (2023), *Cost benefit analysis guidelines*, *Guidelines to make the Integrated System Plan actionable*

2 Problem definition, case for change and response options

This section provides an overview of the problem definition and case for change through the development of the ILM and sets out the Base Case and the strategic response options.

2.1 Develop an Investment Logic Map (ILM)

Consistent with Australian and State Government guidance on investment evaluation, various processes have been undertaken to help identify and measure the prospective problems or opportunities which include investment logic mapping (ILM), benefits dependency mapping, desktop investigations and stakeholder engagement (see **Box 3**).

The ILM underpins the business case and this section follows the ILM structure. The ILM developed in a workshop with key stakeholders from JGN is documented in **Figure 3.**

Box 3: Investment Logic Maps (ILMs)

The development of Investment Logic Maps (ILMs) is increasingly being required as part of Business Cases in a number of jurisdictions across Australia to provide guidance to the Business Case developers on both tangible and intangible value that may be derived from the proposed infrastructure investments.

The development of ILMs is centred on three key concepts:

- The best way to aggregate knowledge is through an informed discussion that brings together those people with the most knowledge of a subject.
- The logic underpinning any investment (the 'investment story') should be able to be depicted on a single page using language and concepts that can be understood by a lay person.
- Every investment should be able to describe how it is contributing to the benefits the organisation is seeking.

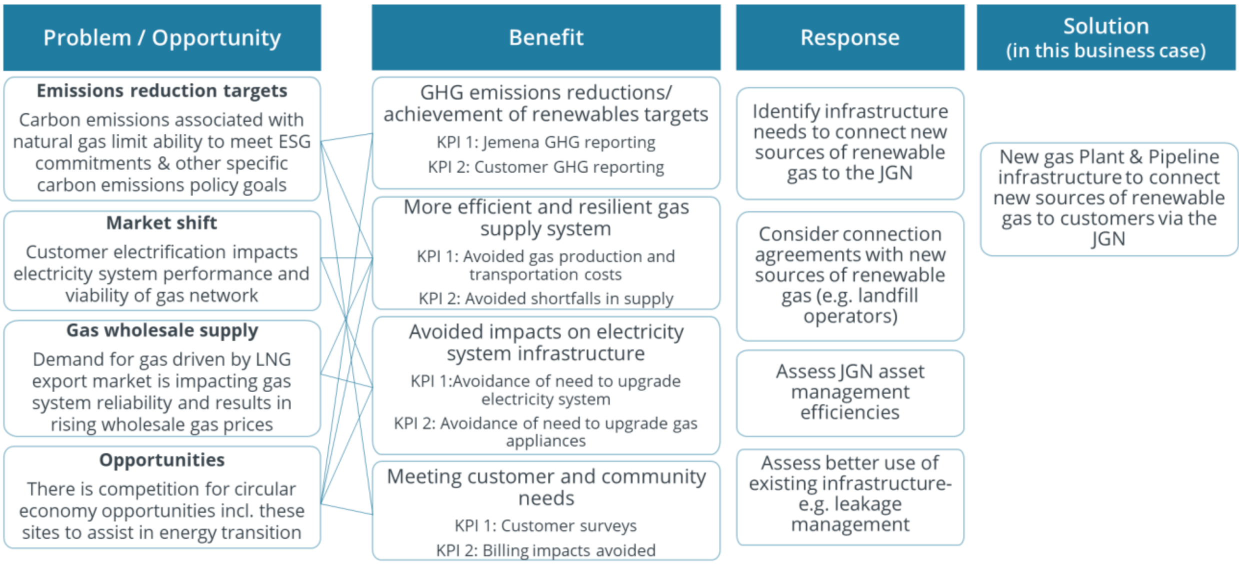
The development of an ILM is typically undertaken for the following reasons:

- The ILM may support the development of the Strategic Business Case and effectively 'set the scene' for further investigating key benefits of the investment.
- The ILM process provides the foundations that align with the NSW Government (Department of Customer Service) Benefits Realisation Management Framework that seeks to articulate why an investment is needed, what strategic outcomes are foreseen, and what are the measurable and realisable benefits.
- As part of Infrastructure NSW's project assurance processes (e.g. Gateway Reviews), it would be required that a Benefits Management Plan be developed as part of the Gate 1 Strategic Options stage whereby the NSW Gate 1 Workbook states that project success factors include "Embedding an end-to-end process to ensure that the benefits and objectives of the investment are realised".[43]

Source: Victorian Department of Treasury and Finance (2017), Facilitator guidance and templates, https://www.dtf.vic.gov.au/investment-management-standard/facilitator-guidance-and-templates

[43] Infrastructure NSW (2023), *Gateway Workbook Strategic Options*, https://www.infrastructure.nsw.gov.au/media/bdwghlab/gate-1-gateway-workbook-november-2023.pdf

Figure 3: Investment logic map for JGN facilitating investment in renewable gas



Source: Frontier Economics

2.2 Defining the problem and opportunity

A series of three problems and a broader opportunity underpins this business case. The key logic behind each is set out in turn below.

2.2.1 Meeting customer and community expectations for emissions reduction

Currently, natural gas is transported exclusively in the JGN (with the exception of small amounts of biomethane produced from the Malabar demonstration plant and hydrogen injected and blended from the Western Sydney Hydrogen Hub). The carbon emissions associated with this natural gas limit JGN and its customers from being able to meet:

- ESG commitments (see **Box 4**) and other specific carbon emissions policy goals including the NSW Government's objective for a 50% reduction in emissions by 2030 compared to 2005 levels (see **Box 5**).[44]
- The National Gas Objective (NGO), in particularly component (b): the achievement of emission reduction targets.

Box 4: Decarbonisation and ESG expectations

Australia is currently in the midst of a significant shift in its energy landscape, as it aims to achieve net zero emissions by 2050. This involves redefining the role of natural gas, impacting both current and future gas customers and introducing uncertainties in the gas sector. As part of JGN's commitment to develop a pricing proposal that is in the long-term interest of customers, and developed through their input, JGN engaged in extensive consultations.

[44] NSW Government, *NSW Climate and Energy Action: Reaching net zero emissions*, accessed 4 January 2024, https://www.energy.nsw.gov.au/nsw-plans-and-progress/government-strategies-and-frameworks/reaching-net-zero-emissions

As part of this process, JGN established the Customer Forum, a group of everyday residential customers and the Key Voices steering groups which utilised an iterative process of building customer personas for young people and CALD communities, to provide insights on preparing the network for decarbonisation. Additionally, JGN engaged with small businesses and retailers.

The Customer Forum focused on determining the best investment and management approach for the 2025-2030 period, considering fairness, uncertainty, and affordability. Through a series of sessions, participants explored the challenges of transitioning the gas network to achieve net zero. They heard from external experts to understand the broader industry context. Both the Customer Forum and Key Voices were very supportive of JGN investing in renewable gas connections. The Customer Forum highlighted biomethane as a priority and advocated for a renewable gas strategy. Biomethane, with its immediate availability and compatibility with existing infrastructure, was seen as a fair solution for current and future customers, ensuring the sustainability of the gas network. Notably, 90% of customers expressed support for adopting renewable gases, particularly biomethane.

Small businesses, heavily reliant on gas as a fuel source, showed significant interest in renewable gases, with 50% of participants voting to expedite its adoption. Retailers were generally supportive, seeing renewable gas as a choice for customers and recognising the need for alternative gas sources for large industrial customers with high-heat processes.

Overall, JGN's customers were overwhelmingly supportive of the inclusion of renewable gases into the network. They see renewable gases as offering choice for customers who do not have the flexibility to electrify due to practical, technical or affordability reasons. Investment in renewable gases provides a decarbonisation pathway for customers now and in the future.

Source: JGN

Box 5: Policy settings supporting decarbonisation of the gas sector

The NSW Government has legislated emissions reduction targets, demonstrating the government's commitment to a net zero future. These include:

- Reducing emissions by 50% on 2005 levels by 2030
- Reducing emissions by 70% on 2005 levels by 2035
- Reaching net zero by 2050
- A requirement to set a 2040 and 2045 interim target.

The Australian Government has legislated greenhouse gas emissions reduction targets that include a plan to reach net zero by 2050 and an emission reduction of 43% below 2005 levels by 2030.

Recent changes to the gas regulatory framework support the gas sector reducing emissions in support of these targets, including:

- The introduction of a **new emissions reduction objective within the National Gas Objective** to recognise that the long term interest of consumers now extends to the achievement of Commonwealth, State and Territory targets for reducing Australia's greenhouse gas emissions, or that are likely to contribute to reducing Australia's greenhouse gas emissions.

- Changes to the framework to **recognise biomethane and hydrogen blends** within the regulatory framework. By early 2024, these new measures will take effect.

More specifically there are several policy settings and initiatives to support decarbonisation of the gas sector through renewable gas, including:

- **Certification of renewable gas**. GreenPower has launched the Renewable Gas Certification Scheme to certify biogas, biomethane and renewable hydrogen projects in Australia and to allow them to create renewable gas certificates that can be sold to commercial and industrial gas users.
- **The Guarantee of Origin scheme**, which is designed to track and verify emissions associated with hydrogen, renewable electricity and potentially other products (including biomethane) made in Australia.
- Federal DCCEEW have implemented a working group to recognise biomethane and hydrogen, through distributed networks, under NGERs as an alternative to natural gas.

The Future Gas Strategy released in May by the Australian Government has included that natural gas should be replaced with low-emissions gases.

Source: NSW Government, NSW Climate and Energy Action: Reaching net zero emissions, accessed 4 January 2024, https://www.energy.nsw.gov.au/nsw-plans-and-progress/government-strategies-and-frameworks/reaching-net-zero-emissions; Australian Government, Future Gas Strategy, May 2024, https://www.industry.gov.au/sites/default/files/2024-05/future-gas-strategy.pdf

2.2.2 Market shift away from gas to electricity consumption

A market trend for customers shifting from gas to electricity consumption poses challenges for NSW. Electrification is forecast to reduce natural gas consumption from residential, small commercial and industrial consumers by 40 PJ in 2043 in NSW.[45] This electrification will require a significant investment in electricity infrastructure to meet the increased demands (estimated to be 8.29 TWh p.a. in 2043 in NSW[46]) on the NSW renewable electricity generation and network infrastructure, as well as investment in new customer appliances. All costs which will ultimately be borne by the customer. A lower cost pathway to net zero emissions involves a mix of renewable gas and renewable electricity.[47]

The 2023 NSW Electricity Supply and Reliability Check Up outlines potential impacts to NSW electricity supply reliability due to a range of factors including the closure of power stations and

[45] AEMO (2024), *2024 Gas Statement of Opportunities*, p. 6, https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2024/aemo-2024-gas-statement-of-opportunities-gsoo-report.pdf?la=en

[46] AEMO (2024), *Integrated System Plan*; https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp

[47] ACIL Allen (2024), *Renewable Gas Target: Delivering lower cost decarbonisation for gas customers and the Australian economy – Report to APGC and ENA, February 2024*, https://acilallen.com.au/uploads/projects/868/ACILAllen_RenewableGasTarget_2024.pdf

difficulties in achieving the state's 2 GW long-duration storage target.[48] Therefore, the market shift will exacerbate challenges to electricity system performance.

With significant fixed costs in the gas system, a market shift away from gas to electricity consumption will also result in higher costs for the remaining gas customers, some of which may not be able to shift to other energy sources. This could also impact the viability of industry operations, resulting in closure of businesses, job losses and loss of choice for customers.

2.2.3 Gas wholesale supply

There are challenges around gas wholesale supply levels in Australia. This is illustrated in AEMO's 2024 Gas Statement of Opportunities which outlines risks of short-term gas supply shortfalls and long-term supply gaps arising from reducing production from southern Australia.[49] Other signals of gas market challenges are interventions in the gas market including the Australian Government's Australian Domestic Gas Security Mechanism and the ACCC's gas price cap.

Demand for gas on East Coast Australia is driven by the LNG export market. This dependency can influence domestic supply availability and negatively impact on the gas system's reliability and/or lead to high wholesale gas prices.

This is a key problem facing gas customers who can only respond to gas supply challenges by reducing their demand or shifting to electricity (noting the significant electrification costs set out in **Section 2.2.2**). Diversification of gas sources to include renewable gas sources would assist in alleviating this problem.

2.3 The opportunity and case for change

Providing renewable gas suppliers with access to the JGN to supply end-gas customers represents a significant opportunity to address the challenges outlined above and support a developing and potentially growing industry.

However, these opportunities are not open-ended and there is competition for this renewable energy source. [redacted]

[redacted]

Connecting a source of renewable gas supply at the site within the 2025-30 AA period therefore represents an opportunity to achieve the benefits outlined in the ILM. Namely:

- Support greenhouse gas emissions reductions and enable achievement of decarbonisation targets in line with customer and community expectations for emissions reduction;

[48] Marsden Jacobs Associates (2023), *NSW Electricity Supply and Reliability Check Up: Prepared for NSW Treasury – Office of Energy and Climate Change (OECC)*, https://www.energy.nsw.gov.au/sites/default/files/2023-09/NSW_Electricity_Supply_and_Reliability_CheckUp_Marsden_Jacob_Report_2023.pdf

[49] AEMO (2024), *2024 Gas Statement of Opportunities*, https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2024/aemo-2024-gas-statement-of-opportunities-gsoo-report.pdf?la=en

- Promote a more efficient and resilient gas supply system;
- Avoided costly impacts on electricity system infrastructure;
- Meeting customer and community needs and giving them a choice in energy supply.

These benefits align with key elements of the NSW Government strategy. Key areas of alignment include:

- Helping to achieve the NSW Government Net Zero Plan target of delivering a 35% reduction in emissions by 2030 compared to 2005 levels. More specifically, it aligns with the number 1 priority in the NSW Government Net Zero Plan to "drive uptake of proven emissions reduction technologies"[50]
- The NSW Circular Economy Policy Statement which includes a principle for the sustainable management of all resources[51]
- NSW Government's commitment to ease cost-of-living pressures for households, for example through energy rebates announced in 2023-24.

2.4 Response options development

This section discusses how credible options were identified and developed.

The credible options are considered for their commercial and technical feasibility, ability to address the identified needs, deliverability, economic and financial benefits, as well as legal and regulatory implications.

2.4.1 The Base Case

The first step of the economic evaluation is to define the Base Case.

The Base Case involves no investment in the JGN at the site to facilitate connection of renewable gas. This involves not allowing the developer to connect and distribute renewable gas to customers. If this were to occur, it is unlikely renewable gas supply will occur to customers at this site given the developer would be unable to source sufficiently directly connected gas customers to justify their investments.

We have assumed in the absence of this investment, some variation of the status quo would continue which could be continuing to [redacted]

2.4.2 Strategic response options

The second step of the economic evaluation is to define several other feasible strategic response options – with each option representing a portfolio of interventions. This section provides an

50 Department of Planning, Industry and Environment (2020), *Net Zero Plan Stage 1: 2020-2030*, https://www.energy.nsw.gov.au/sites/default/files/2022-08/net-zero-plan-2020-2030-200057.pdf

51 NSW EPA (2019), *NSW Circular Economy Policy Statement: Too Good To Waste*, https://www.epa.nsw.gov.au/-/media/epa/corporate-site/resources/recycling/19p1379-circular-economy-policy-final.pdf

overview of the longlist of interventions considered and how these were assessed to establish the Base Case and options to be taken into the CBA.

Consistent with standard business case guidelines, a long list of options was initially developed incorporating the breadth of actions available to JGN as shown in **Table 4**. These were then narrowed down to a single response option through a qualitative assessment by eliminating options which did not meet all four of our pre-defined problems/opportunities identified in the ILM shown in

Table 5.

Table 4: Strategic response options

Options	Description
Base Case: JGN 'Do nothing'	No investment to connect renewable gas to the JGN network at the site.
Leakage management	JGN invests in leakage management to reduce gas leaks within the JGN network system.
Customer demand management	JGN invests in behaviour change campaigns to reduce gas usage and in customer-side leak detection and management.
Emissions offset	JGN invests in emission offsets and carbon offsetting schemes.
Delayed connection to renewable gas (beyond 2025 AA)	JGN begins to invest in connecting renewable gas at the site but only starting in beyond the 2025-30 AA regulatory period.
Connect renewable gas during 2025 AA	JGN begins to invest in connecting renewable gas at the site during the 2025-30 AA regulatory period.

Source: Frontier Economics

Table 5: Qualitative assessment of strategic response options

Options	Emissions reduction targets	Market shift	Gas wholesale supply	Opportunity
Base Case: Do nothing	✗	✗	✗	✗
Leakage management	✓	✗	✓	✗
Customer demand management	✓	✗	✓	✗
Emissions offset	✓	✗	✗	✗
Delayed connection to renewable gas (beyond 2025 AA)	✗	✓	✓	✗
Connect renewable gas at the site during 2025 AA	✓	✓	✓	✓

Source: Frontier Economics

We concluded that the business case should evaluate the economic value of investment in the **Kauri Renewable Gas Project** proposed in the 2025-30 AA (as part of an ongoing program of investment in renewable gas) and whether this is justified under Rule 79(2)(a) of the National Gas Rules.

3 Project options and overview of key costs and benefits

This section sets out the two detailed project options considered and the final project option (Option 1) considered in the business case.

It also provides an overview of the approach to the cost-benefit analysis (CBA) to test the economic value of this option relative to the Base Case in line with Rule 79(2)(a) of the National Gas Rules.

3.1 Project options to connect renewable gas at the site

Two detailed project options (Project Options 1–2) involving different investment scales, technologies, and timeframes were considered. Ultimately only Option 1 was considered credible and appropriate to be tested in the CBA to identify its economic value relative to the Base Case in line with Rule 79(2)(a) of the National Gas Rules as Option 1 could be considered to be strictly better than Option 2 due to the technical supply constraints leading to both options producing the same volume of gas to be injected but Option 2 being more expensive.

[redacted]

Figure 4 shows a map of the two options and **Table 6** provides the rationale for why only Option 1 was considered credible and appropriate to test in the CBA.

[redacted]

Table 6: Project options

Project option	Description	Assessment
Project Option 1: [redacted] annum of renewable gas supplied into the network	Lay [redacted] to connect supplier and JGN network	**Credible option taken forward to be assessed in the CBA.**
Project Option 2: [redacted] (same route as Option 1)	Lay ~[redacted] to connect supplier and JGN network	**Not a credible option.** [redacted]

Source: JGN and Frontier Economics

Project Option 1 involves a pipeline sized for expected gas production at the site including:

[redacted]

- This option involves the connection of the renewable gas injection project to the secondary network. This allows for the full renewable gas potential of the project to be injected into the JGN.

3.2 Identify, quantify and monetise relevant costs and benefits

The next step in the CBA process is identifying the economic value of the costs and benefits that accrue to a defined reference group: **service providers, gas producers, users and end users** [52] [53], as per Rule 79(3)**.**

We estimate the economic value of a range of outcomes from the supply of renewable gas (with a direct causal link) that accrue to the reference group compared to the 'no investment in renewable gas' Base Case:

- Using internally consistent and transparent input variables and parameters, while also accounting for uncertainty by creating "scenarios around the most likely scenario" [54];

52 We have interpreted these recipients in line with definitions of 'registered participants' under the NGR Part 15A.

53 Similar to the clause 5.22.10(d) of the NER, AER's cost-benefit analysis ISP guidelines require the inclusion of any measured cost to generators, distribution network service providers (DNSPs), TNSPs and consumers, and market benefits to those who consume, produce and transport electricity in the market. AER (2023), *Cost benefit analysis guidelines*, *Guidelines to make the Integrated System Plan actionable*, pp. 24-26.

54 AER (2023), *Cost benefit analysis guidelines*, *Guidelines to make the Integrated System Plan actionable*, p. 17.

- Estimating the economic value[55] (rather than financial value) of the costs and benefits over a long-term (30 years) modelling period[56], including the economic value of changes to Australia's greenhouse gas emissions using the AER's VER[57]. The approach to assessing each quantitative cost and benefit is detailed in **Appendix B**;
- Ensuring no double-counting of costs or benefits, and excluding any 'financial or wealth' transfer of value between consumers and producers[58].
- In line with CBA guidance, impacts which cannot be valued have been excluded, and separately described qualitatively.

As show in **Figure 5,** all of the costs and benefits quantified in monetary terms and included in the CBA are from the lens of costs and benefits that accrue to JGN, gas producers, users and end users, including the benefits of emissions reductions as per the NGR and the *National Gas Amendment (Harmonising the national energy rules with the updated national energy objectives) Rule 2024*.

Each of these costs or benefits – depending on whether it represents an improvement or deterioration in economic value compared to the Base Case – is incorporated on the appropriate side of the CBA 'ledger' given economic value is assessed either through a BCR or NPV metric.

Section 5 provides further detail on the assumptions for the distribution of the economic value across the market participants (i.e. who ultimately receives the benefits and who ultimately incurs the costs).

Figure 5: Costs and benefits quantified in the assessment of economic value of the renewable gas expenditure

Market participants	Benefits	Costs
Users/end-users	• Avoided natural gas production and transmission costs • Improved gas supply resilience	
Service provider (JGN)	• Residual value of new pipeline*	• JGN new pipeline costs*
Producers	• Residual value of plant* • Residual value of network connection*	• Plant costs* • Network connection costs* • Foregone value of biogas*
All (directly or indirectly*)	• GHG emission reductions	

* Ultimately borne / received by users / end-users

Source: Frontier Economics

[55] Consistent with the core valuation principle that goods and services are valued at the dollar amounts that individuals are willing to pay for them.

[56] Consistent with the AER's Cost-benefit analysis ISP guidelines, this involves the use of terminal values to reflect the option's expected cost and benefits over the remaining years (i.e. beyond the modelling period) of its economic life. AER (2023), *Cost benefit analysis guidelines*, *Guidelines to make the Integrated System Plan actionable*, p. 76.

[57] Rather than the revenue stream that renewable gas suppliers may receive from the sale of ACCUs.

[58] AER (2023), *Cost benefit analysis guidelines*, *Guidelines to make the Integrated System Plan actionable*, pp. 27, 43.

Unlike a traditional CBA, we have not included other economic, social and environmental costs and benefits that accrue to parties *other* than the market participants listed in per Rule 79(3) (i.e. not applied a broader societal CBA as per NSW Treasury and Infrastructure Australia guidelines). However, for transparency purposes, where there was not sufficient certainty relating to the causal linkage or lack of data to quantify outcomes (such as economic value of changes to scope 3 emissions), we have not estimated the costs and benefits included in the CBA, but separately assessed the costs and benefits qualitatively.

Figure 6 summarises a broader set of incremental costs and benefits we considered resulted from the renewable gas expenditure across three broad categories: economic, social and environmental.[59] We have sought to clearly state which impacts were quantified and included in the CBA.

Where there was not sufficient certainty relating to the causal linkage or lack of data to quantify outcomes (such as economic value of changes to scope 3 emissions), we have not estimated the costs and benefits included in the CBA, but separately assessed the costs and benefits qualitatively.

[redacted]

[redacted]

[59] Noting these categories are purely for presentation purposes only.

[redacted]

Table 7 provides a high-level overview of the quantified costs and benefits. Detailed methodologies, assumptions and data sources are provided in **Appendix B**.

Table 7: **Key quantifiable costs/benefits**

Quantifiable cost/benefit	Description	Key assumptions made / Source
Economic costs and benefits		
Plant capex (cost)	The capital cost of the biomethane plant. These Plant costs are complementary to Pipeline capex (see below). Costs are incurred on both assets to enable the production and distribution of renewable gas.	Sourced from JGN
Pipeline capex (cost)	The capital cost to connect the renewable gas plant and enable supply of renewable gas to users. This includes the connection cost and new pipeline cost categories. These costs are complementary to Plant capex costs (see above).	Sourced from JGN
Plant opex (cost)	The cost of operating and maintaining the biomethane plant.	Sourced from JGN

Quantifiable cost/benefit	Description	Key assumptions made / Source
Residual value of capex (benefit)	The benefit of the capital expenditure that has not been fully depreciated at the end of the CBA appraisal period.	Based on assumed asset lives of 35 years for the biomethane plant and 50 years for the JGN network
More efficient gas supply services – avoided gas production and transmission costs (benefit)	The avoided costs of gas production and transmission of natural gas from reduction in demand for natural gas. This includes the avoided costs of augmenting and operating natural gas production and transmission supply chain assets that would otherwise be required.[60]	Based on a forecast of the gas market price. This price is uncertain. The central case adopts a price forecast that is around $11.07/GJ ($FY2024) on average in real terms over the appraisal period. This price only applies in the assumed times where there is no gas supply shortfall.
[redacted]	[redacted]	[redacted]
Social costs and benefits		
Improved gas supply resilience – avoided costs of a	Injecting renewable gas into the gas network can reduce the quantity of a gas shortfall during times of a supply shortfall.	**Probability of a shortfall**: The probability of a shortfall is uncertain but non-zero. In the central

[60] As noted by NSW Treasury CBA guidelines, the efficiency benefits from reduction in demand on an existing system can be measured through valuing consumer savings directly based on reductions in retail energy prices, ***or*** it could measure the benefit based on estimates of avoided costs through the energy supply chain (incl. lower generation costs, transmission and distribution infrastructure costs and retail costs)." See p. 48. Similarly, NSW Treasury notes, "Based on the opportunity cost principle, benefits of an initiative could be estimated based on the avoided cost of delivering public services no longer required. Treasury (2023), *TPG23-08 NSW Government Guide to Cost-Benefit Analysis*, p. 62, accessed 11 December 2023, https://www.treasury.nsw.gov.au/sites/default/files/2023-04/tpg23-08_nsw-government-guide-to-cost-benefit-analysis_202304.pdf

[61] Based on data from the Lucas Heights Power Station.

Quantifiable cost/benefit	Description	Key assumptions made / Source
gas shortfall (benefit)	In turn, this relates to an economic cost saving for the community which would otherwise have experienced an even larger shortfall in the Base Case.	case, we have assumed 1 day per year of gas shortfall based on a 50% probability of exceedance (POE) forecast (i.e. the forecast value that on average will be exceeded 1-in-2 years) resulting in a 0.137% probability of shortfall each year from 2025.[62] **Willingness to pay to avoid a gas supply shortfall**: We have valued at the market price cap (STTM) of $400.00/GJ ($FY2024).
Environmental costs and benefits		
Economic value of changes to Australia's greenhouse gas emissions - avoided GHG emissions (benefit)	Injecting renewable gas into the gas network reduces the consumption of natural gas and therefore reduces the corresponding greenhouse gas emissions from the natural gas. Part 9 Rule 79(3)(b) of the NGR recognises that it is important to consider the economic value of changes to Australia's greenhouse gas emissions, whether or not that value accrues (directly or indirectly) to the service provider, producers, users or end users during the process of deciding whether the overall economic value of capital expenditure is positive.	**Value of emissions reduction**: $70/tonne in 2024 ($FY2023) increasing by around 7% each year in real terms.[63] **Emissions reduction factor:** Calculated from the change in natural gas consumed and the scope 1 combined gases emission factor for natural gas distributed in a pipeline net of the scope 1 combined gases emissions factor for biomethane (51.4 kg CO2-e/GJ).[64]

Source: Frontier Economics

[62] This is based on the AEMO's 2024 GSOO, Figure 34. https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2024/aemo-2024-gas-statement-of-opportunities-gsoo-report.pdf?la=en. See **Appendix B**.

[63] The average of the IPCC & ACCU prices as per the interim AER VER draft guidance, March 2024. https://www.aer.gov.au/system/files/2024-03/AER%20-%20Valuing%20emissions%20reduction%20draft%20guidance%20-%20March%202024.pdf

[64] DCCEEW (2023), *Australian National Greenhouse Accounts Factors*, p. 17, https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-account-factors-2023.pdf

Table 8 summarises the key assumptions which underpin the CBA.

Table 8: Key assumptions and parameters for the CBA

Assumption/parameter	Value	Source
Year discounted to	1 July 2023 (financial year 2023-24)	Agreed between Frontier Economics and JGN
Price base	30 June 2024	Agreed between Frontier Economics and JGN
Appraisal period	30 years (financial year 2023-24 to 2052-53 financial year)	Agreed between Frontier Economics and JGN
Discount rate	2.49%	JGN 2023-24 real pre-tax WACC[65]

Source: Frontier Economics

[65] JGN Final Decision PTRM 2023-24 RoD update, https://www.aer.gov.au/system/files/JGN%20%E2%80%93%20Final%20Decision%20%E2%80%93%20PTRM%20%E2%80%93%202023-24%20RoD%20update%20%E2%80%93%20PUBLIC%2813692265.1%29.xlsm

4 Project options assessment

The next step in the economic evaluation process involves comparing the present value of the incremental costs and benefits to calculate the net present value (NPV) and benefit-cost ratio (BCR) for the project relative to 'no investment in renewable gas' Base Case.

This section summarises the CBA results and the qualitative assessment of the project option.

4.1 Results of CBA of project options

The findings of our CBA under the *central case* are summarised in **Table 9** and **Figure 8.**

The project option has a positive economic value, and for this reason, is justified under Rule 79(2)(a) of the NGR.

The results of the economic analysis show Option 1 (Preferred Option) with:

- **Net Present Value (NPV)** of $114.40m ($FY2024, NPV) (discounted at 2.49%) compared to the Base Case. This means that investment in the Kauri Renewable Gas Project provides a net increase in economic value of $114.40m ($FY2024, NPV).[66]
- **Benefit Cost Ratio (BCR)** of 1.82 compared to the Base Case. This means that for every $1 of incremental cost incurred in the Kauri Renewable Gas Project there is an increase in economic benefit of $1.82.

These results are driven by the:

- **Benefits** ($254.24m ($FY2024, PV) in present value terms over the modelling period) that accrue to service to gas users, end users, gas producers and gas providers from:
  - more efficient gas supply services valued at the avoided costs of gas production and transmission [redacted] ($FY2024, PV));
  - more resilient gas supply services valued at the avoided costs of a gas shortfall [redacted] ($FY2024, PV));
  - economic value of changes to Australia's greenhouse gas emissions from the displacement of natural gas consumption [redacted] ($FY2024, PV)), monetised using the AER published VER;
  - residual value of the Plant and Pipeline [redacted] ($FY2024, PV));

outweighing the

- **Costs** [redacted] ($FY2024, PV) over the modelling period) that accrue to service to JGN (as service provider), gas producers, users and end users from:
  - JGN pipeline capex [redacted] ($FY2024, PV));
  - Plant capex[67] [redacted] ($FY2024, PV));
  - Plant opex [redacted] ($FY2024, PV));
  - Foregone use of biogas for other purposes [redacted] ($FY2024, PV)).

[66] NPV is the preferred metric to rank investments under the National Electricity Rules (NER clause 5.15A.1(c)), reflected in the AER's Cost-benefit analysis ISP guidelines.

[67] The Plant costs are complementary to JGN Pipeline capex. Costs are incurred on both assets to enable the production and distribution of renewable gas.

See **Appendix B** for more detail on the methodologies used to estimate the economic value, in monetary terms, of the costs and benefits in the CBA. The qualitative assessment of the non-monetised impacts (see **Table 10**) is in addition to the estimated economic value in monetary terms.

Table 9: Summary of cost-benefit analysis – central case ($m, $FY2024, NPV)

	Project Option 1 (incremental to the Base Case) ($m, $FY2024, PV)
Benefits	
Residual value of plant and pipeline capital costs	[redacted]
More efficient gas supply services – avoided natural gas production and transmission costs	
Economic value of changes to Australia's greenhouse gas emissions – avoided GHG emissions	
Increase gas supply resilience – avoided costs of a gas shortfall	
Total benefits	**254.24**
Costs	
Plant capex	[redacted]
Pipeline capex	
Plant opex	
Foregone use of biogas for other purposes	
Total costs	
Net present value	**114.40**
Benefit cost ratio	**1.82**

Source: Frontier Economics

[redacted]

4.2 Qualitative assessment of non-monetised impacts

Due to the informational and data constraints that prevent robust quantification, the quantified incremental economic value to the community does not include impacts that have not been monetised as part of the CBA. These unquantified benefits have been assessed qualitatively for their likely impact which is summarised in **Table 10**.

Given that some of the non-monetised benefits potentially have a material impact on the value of Project Option 1, the estimated economic value of Project Option 1 is likely to be understating the economic value it provides.

Table 10: Qualitative assessment

Qualitative cost/benefit	Description	Likely impact
Economic costs and benefits		
Avoided costs of switching appliances	Customers that would electrify in the absence of a renewable gas option are likely to incur additional costs in converting	**Either beneficial or neutral**

Qualitative cost/benefit	Description	Likely impact
	their appliances and energy use facilities. Electrical alternatives to gas appliances and gas processes are often higher cost and likely also require additional expenditure to install required wiring. Electrification may also bring forward replacement of appliances, processes and facilities, increasing lifetime costs.	Reduced expenditure on appliances, processes and facilities that would be required for electrification is a benefit. However, it is difficult to establish the direct causal link between the availability of renewable gas, the rate of electrification and the additional appliance and process costs incurred by specific customers (particularly large industrial customers that have unique energy characteristics).
Avoided costs of electricity network augmentation	Customers that would electrify in the absence of a renewable gas option will increase demand for electricity and likely lead to additional expenditure on the electricity network to meet that demand. Since those customers are already supplied through the gas network, additional expenditure on the gas network is less likely if they remain on the gas network.	**Either beneficial or neutral** Reduced expenditure on the network augmentation that would be required for electrification is a benefit. However, it is difficult to establish the direct causal link between and the availability of renewable gas, the rate of electrification, and the additional impact on the network (in terms of changes to peak electricity demand).
Avoided costs of localised supply disruptions	Renewable gas supply has potential to improve security of supply both in terms of geographical diversity in location and the number of producing projects injecting into the gas market at any one time.[68]	**Minor benefit** By supporting decentralised supply this reduces the likelihood of supply disruption (it is likely a minor benefit due to the low likelihood of transmission or distribution supply outage). This is an additional benefit over and above the tightness of the overall supply-demand balance in the domestic market.
Supporting existing industry	Supporting continued use of gas supply for those customers unable to electrify	**Major benefit** By supporting decarbonisation and incentives to remain connected to the gas network, JGN can continue to invest in and provide gas network services, ensuring existing industries that are reliant on gas are able to continue to operate in Australia.

[68] AEMC (2022), *Review into extending the regulatory frameworks to hydrogen and renewable gases, Final rules report*, p. ii, p. 10.

Qualitative cost/benefit	Description	Likely impact
Social costs and benefits		
Supporting the local economy	The renewable gas project provides employment at the project site (through the construction and ongoing operation of the plant).	**Either minor benefit or neutral** Employment is often not included as a separate benefit in a cost-benefit analysis as it is difficult to determine whether the employment is truly incremental or whether the employment transfers to or from another region or industry (e.g. from electricity generation to biomethane production). Given the emissions targets driving investment in renewable electricity generation, it is likely this investment increases rather than transfers employment. However, it has not been possible to robustly quantify the value of increased employment. It is unclear if this benefit accrues to JGN, gas producers, gas users and users. .
Environmental costs and benefits		
Value of emissions reduction (other than scope 1 emissions from use of natural gas – see **Appendix B**)	Renewable gas supply has the potential to reduce scope 3 emissions associated with delivering gas to end users and associated with fugitive emissions.	**Either beneficial or neutral** Renewable gas supply close to customers is likely to reduce scope 3 emissions associated with delivering gas to end users, relative to supply from more distant gas fields. Renewable gas supply may also reduce fugitive emissions. The reduction in scope 3 emissions may be material. We note that to quantitatively calculate the change in greenhouse gas emissions, we have only considered the change in scope 1 emissions from natural gas displacement at 51.4 kg CO2-e/GJ (see **Table 21**) and have considered all other changes qualitatively. This is due to the uncertainty as to how to calculate the additional scope 3 and other emissions.
Supporting circular	The renewable gas project contributes to the circular economy through the sustainable	**Either beneficial or neutral**

Qualitative cost/benefit	Description	Likely impact
economy outcomes	management of the landfill and incentives for innovation in new solutions for resource efficiency of landfill waste, lowering overall costs or impacts of landfill management.	The renewable gas project does support the circular economy through the efficient use of landfill biogas. There is evidence that the community is willing to pay for circular economy outcomes. It is unclear if this benefit accrues to JGN, gas producers, gas users and users.

Source: Frontier Economics

4.3 Sensitivity analysis

Forecasting costs and benefits is an uncertain process. There are a significant number of factors or risks that will influence the timing and quantum of costs and benefits and ultimately the overall economic value delivered to the community.

This section summarises the findings of our sensitivity and scenario analysis for the preferred Project Option 1 to test the robustness of the results. This analysis includes considering the value of the project options under:

- Changes to *individual* assumptions through sensitivity analysis (leaving other assumptions unchanged);
- Changes to *several* key assumptions through scenario analysis (known as 'global' high-value or low-value scenarios) which are more likely to represent 'bookends' (summarised in **Table 11** and further defined below).

The scenarios relate to the value of the NPV the sensitivity produces (i.e. does it produce higher or lower economic value) and not the value of the parameter itself. For example, the low value scenario's capex and opex are 20% higher than the central scenario's capex and opex as it results in a lower NPV.

This global sensitivity analysis indicates that the community value delivered by Project Option 1 is likely to range between [redacted] under the high and low value scenarios, shown in

Figure 9 and **Figure 10** respectively. Rather than expected values, these represent bookends of possible scenarios given the likelihood of these sets of assumptions occurring simultaneously is low.[69] The BCR ranges [redacted]

[69] That is, it is unlikely that higher expenditure (+20%), a lower domestic gas price, a lower renewable gas production and low assumed carbon value – all of which lower the economic value of the project relative to the central estimate – occur simultaneously.

Table 11: Global sensitivity analysis scenarios for Option 1

Key input assumption	Global low-value scenario	Central scenario	Global high-value scenario
Capex and opex	+20%	JGN estimates	-20%
Value of emissions reduction (VER)	VER (-25%): $52.50 in 2024 ($FY2023), escalated by CPI+~7%	VER: $70.00 in 2024 ($FY2023), escalated by CPI+~7%	VER (+25%): $87.50 in 2024 ($FY2023), escalated by CPI+~7%
Domestic gas price[70]	-22% ($8.64/GJ)	$11.07/GJ	+76% ($19.48/GJ)
Probability of shortfall	0.014%	0.137%	0.274%
Renewable gas production	-20%	JGN estimates	+20%

Source: Frontier Economics

[redacted]

[redacted]

We have undertaken additional sensitivity analysis by looking at the impact of individual assumptions of key drivers of value when they are changed to their low and high values (shown in **Table 12**) for Project Option 1. These sensitives are defined as the following:

- **Capex and opex:** The capital and operating costs for the plant and pipeline being 20% higher and 20% lower.
- **Value of emissions reduction:** The value of emissions reduction at the interim VER and following the AEMC's guidance to undertake sensitivity analysis using values up to 25% higher or lower than the VER.[71]
- **Domestic gas price:** The value of the domestic gas price has separate price forecasts for low price and high price scenarios (refer to **Appendix B**).
- **Probability of a shortfall:** The probability of a gas shortfall each year has separate estimates for low probability and high probability scenarios (refer to **Appendix B**).
- **Renewable feedstock volumes and gas production efficiency:** This sensitivity tests the uncertainty of input feedstock volumes (how much feedstock is available) as well biomethane

[70] Prices are the average prices over the 30-year period in $FY2024.

[71] AEMC (2024), *How the national energy objectives shape our decisions, Final guidelines, 28 March 2024;* https://www.aemc.gov.au/sites/default/files/2024-03/AEMC%20guide%20on%20how%20energy%20objectives%20shape%20our%20decisions%20clean%20200324.pdf

production efficiency (how much is produced for a given level of feedstock) at 20% higher or 20% lower.

- **Discount rate:** A discount rate of 7% was tested as a low scenario as a higher discount rate leads to a lower NPV and BCR.

Table 12: Individual sensitivity analysis for Option 1

Sensitivity scenario	Sensitivity value	Net present value ($m, $FY2024)	Benefit cost ratio
Capex and opex			
Low	+20%	[redacted]	
Central	JGN estimates		
High	-20%		
Value of emissions reduction			
Low	VER (-25%): $52.50 in 2024 ($FY2023), escalated by CPI+~7%	82.43	1.59
Central	VER: $70.00 in 2024 ($FY2023), escalated by CPI+~7%	114.40	1.82
High	VER (+25%): $87.50 in 2024 ($FY2023), escalated by CPI+~7%	146.37	2.05
Domestic gas price[72]			
Low	-22% ($8.64/GJ)	88.37	1.63
Central	$11.07/GJ	114.40	1.82
High	+76% ($19.48/GJ)	206.00	2.47
Probability of supply shortfall (each year from 2025)			
Low	0.014%	[redacted]	
Central	0.137%		
High	0.274%		
Renewable feedstock volumes[73]			
Low	-20%		
Central	JGN estimates		

72 Prices are the average prices over the 30-year period in $FY2024.

73 This sensitivity tests the uncertainty of input feedstock volumes and its corresponding impact to plant operating costs and gas production volumes.

Sensitivity scenario	Sensitivity value	Net present value ($m, $FY2024)	Benefit cost ratio
High	+20%	[redacted]	
Renewable gas production efficiency[74]			
Low	-20%		
Central	JGN estimates		
High	+20%		
Discount rate			
Low	7.00%	34.26	1.37
Central	2.49%	114.40	1.82

Source: Frontier Economics

[74] This sensitivity tests the uncertainty of the technology to convert feedstock into biomethane where the inputs and costs remain fixed, but the biomethane production and injection volumes and its corresponding benefits vary.

5 Distributional and funding analysis

This section sets out the distributional and funding analysis for the project across the participants in the market (i.e. JGN, gas producers, users and end users).

5.1 Distributional analysis

The CBA in this business case is focused on efficiency in that it demonstrates that the expenditure is justified under Rule 79(2)(a) as the *overall* economic value is positive (NPV>0; BCR>1), calculated in accordance with Rule 79(3).

While under the NGR, and under the AER's CBA guidelines for ISP, the distributional effects should not influence regulatory decision-making[75], it is standard practice in a business case to provide information on the distribution of this economic value, including issues of who *ultimately* receives the benefits and who *ultimately* incurs the costs.

In terms of the distribution of this value across the participants in the market, we conclude that gas users are overwhelmingly the ultimate impactors and beneficiaries of these renewable gas investments (including Plant and JGN pipeline capex) with the costs and benefits primarily borne or received by gas users.

5.1.1 Costs

In relation to costs, gas users will be the ultimate impactors driving the need for investment in renewable gas projects.

The investment in renewable gas projects is driven by future demand for gas by customers: that is, by the need to address customer, policy and regulatory expectations that there is a decarbonisation pathway for future natural gas supply to customers that contributes to reducing Australia's greenhouse gas emissions. To the extent that this investment is also driven by the value of reducing gas supply shortfalls in meeting future demand only emphasises that gas users are driving the need for this investment.

The concept of customers being the 'impactors' has significant regulatory precedent.

For example, it is consistent with the approach adopted in electricity networks, where the AEMC has previously argued that investment in electricity supply is caused by customer load:

> *"the majority of transmission investment in the shared meshed network is undertaken to meet the reliability obligations imposed to satisfy the requirements of consumers rather than to meet the requirements of generators to evacuate power. In other words, most transmission investment is 'caused by' load rather than generation."*[76]

In addition, it is also consistent in across many sectors where there are policy and/or regulatory expectations that require costs to be incurred to comply with social or environmental outcomes in the delivery of services. As noted in IPART's review of cost sharing:

> *Legislation and regulation is constantly changing in a range of activities and the costs of complying with such regulation is typically absorbed by the party which has to comply and then passed on to users of the products or services which they supply.*

75 AER (2023), *Cost benefit analysis guidelines, Guidelines to make the Integrated System Plan actionable*, p. 42.

76 AEMC (2006), *Rule Determination for National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006*, 21 December 2006, p. 21.

> *Legislation or regulation requires Water NSW to comply with certain obligations, and this represents part and parcel of the costs to Water NSW of supplying its services and should properly be recovered from users. To do otherwise would be to subsidise the costs of activities required in supplying services to those users.*[77]

In terms of the Plant and Pipeline investments required to enable renewable gas supply, we have disaggregated the capital and operating costs for the project into the following categories:

- **Plant costs**, which covers the cost of building and operating the renewable gas plant;
- **Pipeline costs** which includes the network connection costs required to receive gas from the renewable gas plant plus new pipeline cost required to build and operate a new pipeline or mains extension from the receipt point to the existing network;
- **Foregone value of biogas**, which is an opportunity cost from producing renewable gas (i.e. the value set with reference to the market price if biogas was used for another purpose).

Each of these cost categories will be initially funded by different stakeholders (our funding analysis is set out in the next section).

However, for the purposes of this distributional analysis, we have assumed that all capital and operating costs associated with the project will *ultimately* be passed through to gas users directly via JGN network tariffs and/or via gas supply & transport contracts paid for gas supply.[78] Given that in many markets costs are shared between parties, considering the *ultimate* incidence of the costs is consistent with best practice distributional analysis.

5.1.2 Benefits

In relation to benefits, gas users will be the ultimate beneficiaries from investment in renewable gas projects.

Gas users will benefit from avoided natural gas production and transmission costs and improved supply resilience from reducing the 'draw' on existing or future gas fields. This will be in the form of reductions in retail prices for gas supply[79] and the avoided costs of a gas supply shortfall and/or interruptions.[80]

As noted by the AEMC in the context of the value of hydrogen and renewable gases in the east coast gas market:

> *... this potential additional security is likely to have material value to the east coast gas market, contingent on the size of the new industry that eventuates, and the degree to which hydrogen and renewable gas projects are dispersed across the east coast gas market...*

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[77] Frontier Economics (2016), *Review of WaterNSW cost shares*: Report prepared for IPART. https://www.ipart.nsw.gov.au/sites/default/files/documents/consultant-report-by-frontier-economics-review-of-waternsw-cost-shares.pdf

[78] Given gas producers will seek to recover their Plant costs through charges they negotiate with gas shippers / retailers for the supply of renewable gas.

[79] As noted by NSW Treasury CBA guidelines, the benefits that accrue to end-users from a reduction in demand on an existing system can be measured through valuing consumer savings directly based on reductions in retail energy prices, ***or*** it could measure the benefit based on estimates of avoided costs through the energy supply chain (incl. lower generation costs, transmission and distribution infrastructure costs and retail costs. NSW Treasury (2023), *TPG23-08 NSW Government Guide to Cost-Benefit Analysis*, p. 62.

[80] As noted in the AER's *Network resilience* note, customers or users are the beneficiaries of investment to avoid or reduce the frequency or duration of outages, and that utilities "should explain to its customer base that the benefits associated with upfront investment in resilience expenditure to address a localised low probability, high consequence event outweigh the costs." AER (2022), *Network resilience*, accessed 11 December 2023, p. 13, https://www.aer.gov.au/system/files/Network%20resilience%20-%20note%20on%20key%20issues.pdf

> ***Under this scenario, benefits will also be in the form of improved security of supply for gas users…and potential longer term economic benefits in cost terms depending on longer term cost and price structures in global gas markets****.* *[emphasis added]*[81]

Gas users will also be a key beneficiary from the economic value of changes to Australia's greenhouse gas emissions resulting from supply of renewable gas (noting we have monetised the emissions reductions associated with reducing scope 1 emissions only).[82] Assuming the value of this emissions reduction accrues to gas users is a core principle under the National Gas Objectives in that it is in the long-term interest of customers for efficient investment in efforts to reduce Australia's greenhouse gas emissions.[83]

The benefits from the residual value of the plant and pipeline have also been assumed to be received by gas users on the expectation that the plant and pipeline would continue to provide benefits to gas users after the modelling period, and these benefits would at least be equal to the residual value of the assets.

Table 13 provides a high-level distribution of the costs and benefits across the market participants. It shows that the costs and benefits that have been monetised in the CBA (i.e. excluding costs and benefits set out in the qualitative analysis) are primarily borne or received by gas users. Based on this analysis gas users (as a whole) are significantly 'better off', in that the benefits received by gas users exceed the costs they ultimately incur.

81 AEMC (2022*), Review into extending the regulatory frameworks to hydrogen and renewable gases, Final rules report,* p. ii, p. 10.

82 This is distinct from the financial value available to gas producers from the sale of ACCUs (noting the value of ACCUs is significantly below the economic value of emissions reductions in the recently published VER).

83 The AER notes that the value of emissions reductions is one of the central considerations in determining if AER decisions are in the long-term interest of consumers. AER (2023), *AER guidance on amended National Energy Objectives*, September 2023, p. 4.

Table 13: High-level distribution of costs and benefits across the community

Category	Ultimately incurred or received by	Value of cost or benefit ($m, $FY2024, PV)
Benefits		[redacted]
More efficient gas supply services – avoided natural gas production and transmission costs	Gas users	
Economic value of changes to Australia's greenhouse gas emissions – avoided GHG emissions	Gas users (directly or indirectly)	
Increased gas supply resilience – avoided costs of a gas shortfall	Gas users	
Residual value of plant and pipeline capital costs	Gas users	
Costs		
Plant – capital costs	Gas users	
Pipeline – capital costs	Gas users	
Plant – operating costs	Gas users	
Foregone use of biogas for other purposes	Gas users	

Source: Frontier Economics

5.2 Funding analysis

While both JGN Pipeline costs (including the connection cost and new pipeline costs) and renewable gas Plant costs are complementary investments – in that both are required to enable the production and distribution of renewable gas to our customers – the AER is only required to form a view on whether the JGN Pipeline costs conforms with the new capital expenditure criteria set out in Rule 79(1) of the National Gas Rules.

To support this decision-making we have considered how the JGN pipeline costs of the renewable gas project will be allocated and funded. Rule 93(2) requires costs to be allocated between reference and other services as follows:

- costs directly attributable to reference services are to be allocated to those services;
- costs directly attributable to pipeline services that are not reference services are to be allocated to those services; and
- other costs are to be allocated between reference and other services on a basis (which must be consistent with the revenue and pricing principles) determined or approved by the AER.

The AER has approved JGN's reference service proposal for the 2025-30 regulatory period.[84] Specifically, the AER has accepted JGN's proposal to include two reference and two non-reference services. These services are described in **Box 7** below.

Box 7: JGN's reference services and non-reference services for 2025-30

Reference services

The **Transportation Reference Service** is a service for:

- the transportation and delivery of Gas by the Service Provider through the Network to an eligible Delivery Point and
- meter related services including:
  - the provision, installation and maintenance of a standard metering installation; and
  - meter reading and associated data activities as appropriate for the required capacity and meter reading frequency but does not include Ancillary Reference Services.

The **Ancillary Reference Service** are those services set out in the Ancillary Reference Service Schedule as requested by a User for an eligible Delivery Point. (This covers things like special meter reads, disconnection (volume customers), reconnection (volume customers), disconnection and reconnection (demand customers), abolishment, hourly charge – non-standard requests and expedited reconnection).

Non-reference services

An **Interconnection Service** is a service provided by the Service Provider to connect a Pipeline or facility to the Network and:

- to establish a Delivery Point to enable the delivery of Gas from the Network; or
- to establish a Receipt Point to enable the receipt of Gas into the Network,

in accordance with Part 6 of the National Gas Rules including the Service Provider's Interconnection Policy.

A **Negotiated Service** is where a Prospective User has specific needs which differ from those which would be satisfied by the Reference Service or the Interconnection Service. The Prospective User may seek to negotiate different terms and conditions as a Negotiated Service and enter into a Service Agreement with the Service Provider.

Source: JGN, Reference service proposal for the July 2025 – June 2030 regulatory period, 26 October 2023.

[84] AER (2023), *Final Decision Jemena Gas Networks (NSW) Ltd Gas Distribution Determination 2025 to 2030 – Reference Services, November 2023.*

As indicated above, JGN will incur capital and operating costs associated with connecting the renewable gas plant. These are the connection cost and new pipeline cost categories, as defined in the preceding section. We have allocated these costs to the reference and non-reference services consistent with the requirements in Rule 93(2). Specifically, we consider that:

- The new network and pipeline costs are directly attributable to the transportation reference service as they include the costs that JGN will incur to transport gas through the network to a delivery point. Gas users are the 'impactors' of these costs given demand from gas users is creating the need to incur costs to reduce greenhouse gas emissions.[85] In view of this, we consider that the new pipeline costs should be recovered from reference service tariffs.
- The custody transfer costs are directly attributable to the interconnection non-reference service as they include the costs that JGN will incur to establish a receipt point to enable the receipt of gas into the network. In view of this, we consider that these connection costs should be recovered from the proponent (via an interconnection fee, in line with JGN's Interconnection Policy). We note that an alternative view is that these costs could be allocated to the transportation reference service given that gas users as 'impactors' are also creating the need to incur costs to reduce greenhouse emissions.

[85] Consistent with the impactor pays principle. As articulated by the AEMC "transmission prices should generally be set on a 'causer pays' basis where possible…[and] most transmission investment is 'caused by' load rather than generation." AEMC (2006), *Rule Determination, National electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 No. 22,* https://aemc.gov.au/sites/default/files/content/dfd89237-4c6b-44ea-a251-c611dc715d21/Rule-Determination.pdf

6 Recommendation and delivery case

Based on the analysis in this business case we conclude that investment (Option 1) in the **Kauri Renewable Gas Project**:

- Is justified under Rule 79(2)(a) of the National Gas Rules as the overall economic value is positive (NPV>0; BCR>1), calculated in accordance with Rule 79(3), and is justified under Rule 79(2)(c)(v) as the investment is necessary to meeting emissions reduction targets through the supply of pipeline services;
- Aligns with JGN's customers' preferences, stakeholders' interests and broader Australian Government and NSW Government policy including NSW Government Net Zero Plan to "drive uptake of proven emissions reduction technologies";[86]
- Results in gas users (as a whole) being significantly 'better off' in that the benefits received by gas users exceed the costs they ultimately incur. This includes more efficient gas supply services, increased gas supply resilience, an economic value of changes to Australia's greenhouse gas emissions (in the form of avoided GHG emissions), and the ongoing value of plant and pipeline capital assets to provide renewable gas to customers beyond the modelling period.
- Aligns to broader regulatory guidance by the AER and other economic regulators in Australia related to funding of projects that promote resilience in the supply of services.

If the AER does not approve this JGN expenditure, it is unlikely JGN will proceed with this investment, which means renewable gas supply will not occur at this site. This is because it is unlikely that renewable gas supply proponents would be able to source sufficiently directly connected gas customers to justify their investments. This means that the estimated net positive economic value from the **Kauri Renewable Gas Project** – that is primarily received by gas users – will not be realised. In our view, this would not be in the long-term interest of customers and the amended NGO.

For this reason, we recommend:

- JGN invest in network infrastructure to provide renewable gas suppliers at the site with access to the JGN in turn enabling renewable gas supply to gas users (as a whole);
- AER allow JGN to recover the efficient costs of providing *reference services* (which is a proportion of the costs that JGN will incur to enable renewable gas supply to gas users) from its reference services charges via its 2025-2030 Access Arrangement.

This recommendation is subject to JGN providing a sound implementation plan to ensure the procurement and delivery approach meets governance standards and maximises project benefits to gas users and the overall community.

[86] Department of Planning, Industry and Environment (2020), *Net Zero Plan Stage 1: 2020-2030*, https://www.energy.nsw.gov.au/sites/default/files/2022-08/net-zero-plan-2020-2030-200057.pdf

A Other regulatory guidance

Other AER regulatory guidance

In addition to the National Gas Rules there is other regulatory guidance from the AER that is relevant to identifying the option that maximises the present value of net economic benefits to all those that produce, consume and transport gas as well as the broader Australian community. While these currently apply to electricity transmission and/or distribution, the key principles in these guidelines are relevant for this project which are discussed in **Table 14** below.

Table 14: Other AER regulatory guidance

Guidance description	Relevance to this project / how we have considered and addressed the guidance
Network Resilience guidance note:[87] The AER requires the following evidence to support ex-ante resilience related funding: • There is a causal relationship between the proposed resilience expenditure and the expected increase in extreme weather events. • The proposed expenditure is required to maintain service levels and is based on the option that likely achieves the greatest net benefit of the feasible options considered. • Consumers have been fully informed of different resilience expenditure options, including the implications stemming from these options, and that they are supportive of the proposed expenditure.	The cost-benefit analysis considers the environmental benefit of avoided greenhouse gas emissions. JGN has tested customer preferences in relation to renewable gas investments on their bill impacts for the forthcoming AA period and they are supportive of the inclusion of renewable gases into the network.
Cost benefit analysis guidelines:[88] The AER's cost-benefit guidelines are for AEMO in preparing an integrated system plan and for transmission network service providers in applying the RIT-T to actionable ISP projects. It provides the following guidance:	All future costs and benefits are discounted using a discount rate appropriate for the analysis of private enterprise investment in the sector (JGN's real pre-tax WACC of 2.49%) and is required to be consistent with the cash

[87] AER (2022), *Network resilience*, accessed 11 December 2023, https://www.aer.gov.au/system/files/Network%20resilience%20-%20note%20on%20key%20issues.pdf

[88] AER (2023), *Cost benefit analysis guidelines*, *Guidelines to make the Integrated System Plan actionable*, https://www.aer.gov.au/system/files/2023-10/AER%20-%20CBA%20guidelines%20-%20final%20amendments%20%28clean%29%20-%206%20October%202023_0.pdf

Guidance description	Relevance to this project / how we have considered and addressed the guidance
• The discount rate is required to be appropriate for the analysis of private enterprise investment in the electricity sector across the National Electricity Market (NEM), and is required to be consistent with the cash flows that the ISP is discounting. • To meet the above requirement, AEMO should select a discount rate(s) that reflects the systematic risk associated with the expected cost and market benefit cash flow streams over the life of the projects in a development path. • The lower boundary should be the regulated cost of capital, based on the AER's most recent regulatory determination at the time of the final ISP. If there is more than one option (for example, if there were two 'most recent regulatory determinations' that were published simultaneously), AEMO should choose a value between the options that best reflects the requirement. • Discretionary principles: Internal consistency, Plausibility, Verifiable sources, Relevance, Transparency	flows of the CBA. JGN's real pre-tax WACC of 2.49% reflects their regulated cost of capital. We have transparently laid out our assumptions for the CBA in **Appendix B** and have cited their sources.

Source: Frontier Economics

Other Australian regulatory guidance

Other regulators in Australia have considered how to identify and incentivise utilities to invest in options that maximise the present value of net economic benefits. **Table 15** below provides a brief overview of this guidance, its relevance to this project and how we have considered and addressed this guidance material in preparing the cost-benefit analysis and this business case.

Table 15: Other Australian regulatory guidance

Guidance description	Relevance to this project / how we have considered and addressed the guidance
QCA's climate change resilience funding framework:[89] In assessing a climate-related proposal, the QCA's first consideration will be how it forms part of a broader, coherent strategy that sets out clear and justifiable goals—and identifies a pathway for achieving those goals. The strategy should be developed in consultation with customers and other relevant stakeholders. The business plan supporting a proposal should demonstrate the need for the spending, outline the consultation with stakeholders, explain how options were considered, and show that the cost is efficient.	The cost-benefit analysis considers the environmental benefit of avoided greenhouse gas emissions.
NSW Treasury CBA guidance:[90] This provides a broad framework for conducting CBAs across NSW Government. This includes the basics of CBA being an incremental analysis of the impacts of an intervention to NSW society compared to a base case. Specific features of the guidance include: • Identifying that the benefits of initiatives seeking to improve the resilience of a system include: ○ Savings or avoided cost ○ Benefits to the broader community ○ Residual value • Identifying common issues in CBA including: ○ Avoiding double counting of benefits	We have considered a range of incremental, economic, social and environmental costs and benefits where a direct causal linkage could be established between the project options and the change in 'real resource' outcomes (including market and non-market impacts) and thus have excluded financial transfer payments.

89 Queensland Competition Authority (2023), *Approach to climate change related expenditure*, accessed 11 December 2023, https://www.qca.org.au/wp-content/uploads/2023/09/qca-climate-change-final-position-paper-september-2023.pdf and Queensland Competition Authority (2023), *Climate change related spending*, accessed 11 December 2023, https://www.qca.org.au/wp-content/uploads/2023/09/qca-climate-change-guideline-september-2023.pdf

90 NSW Treasury (2023), *TPG23-08 NSW Government Guide to Cost-Benefit Analysis*, accessed 11 December 2023, https://www.treasury.nsw.gov.au/sites/default/files/2023-04/tpg23-08_nsw-government-guide-to-cost-benefit-analysis_202304.pdf

Guidance description	Relevance to this project / how we have considered and addressed the guidance
○ Excluding sunk costs, depreciation and interest from a CBA ○ Excluding transfer payments (a financial payment between two parties in NSW which doesn't make society any better or worse off). Taxes and subsidies are examples of transfer payments.	
Infrastructure Australia guide to economic appraisal:[91] They identify CBA as the standard technique for economic appraisal. They state "(T)he analysis is social in the sense that it takes into account all the impacts on the welfare and wellbeing of society". Infrastructure Australia summarise CBA as a nine step process: • Step 1: Articulate the problems and opportunities being addressed • Step 2: Identify the base case and project case options • Step 3: Identify costs and benefits and how they are measured • Step 4: Forecast the demand and impacts over the life of the investment • Step 5: Monetise the costs and benefits • Step 6: Identify non-monetised impacts • Step 7: Discount costs and benefits to determine the net benefit • Step 8: Analyse risks and test sensitivities • Step 9: Report on CBA results Having a well-defined base case can be critical to a CBA. Infrastructure Australia state that their preferred approach to a CBA is to "the committed and funded expenditure approach", as opposed to including	The Base Case reflects a set of measures that are most in line with a 'business as usual' approach to system intervention. This reflects a 'do nothing' scenario. We have considered a range of incremental, economic, social and environmental costs and benefits where a direct causal linkage could be established between the project options and the change in 'real resource' outcomes (including market and non-market impacts). This includes upfront and ongoing costs and benefits. We have attempted to monetise impacts where we have sufficient information, with the costs and benefits of all options calculated relative to the Base Case. In the case of non-market costs and benefits, we have adopted benefit-transfer. We have included impacts that we could not monetise qualitatively, and for those impacts that are likely to be material. We have included a sensitivity analysis that reflects potential alternative settings for key assumptions that drive value. This includes considering the value of the project options under: • Global high-value or low-value scenarios; and • When individual key drivers of value are changed.

[91] Infrastructure Australia (2021), *Guide to economic appraisal* accessed 11 December 2023, https://www.infrastructureaustralia.gov.au/sites/default/files/2021-07/Assessment%20Framework%202021%20Guide%20to%20economic%20appraisal.pdf

Guidance description	Relevance to this project / how we have considered and addressed the guidance
interventions which are simply in plans or strategy documents. Infrastructure Australia does not present a specific view on valuing carbon (reflecting the fact that Infrastructure Australia seek to minimise contradicting state and territory treasury guidance).	Our analysis presents the net present value (NPV) and benefit cost ratio (BCR) results.

Source: Frontier Economics

B Key valuation methodologies and assumptions in CBA modelling

Inflation

Inflation has been applied to convert the dollar figures into $FY2024 where relevant. The Consumer Price Index for Australia (all groups), Series ID A2325846C, sourced from the Australian Bureau of Statistics[92] and the Reserve Bank of Australia's CPI forecast for June 2024[93] has been used to inflate the dollar figures.

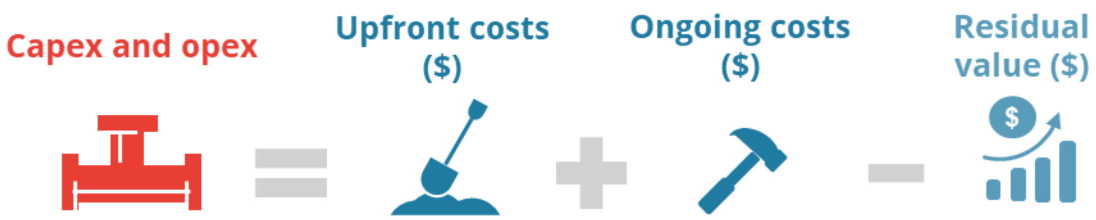
Capital and operating expenditure of the plant and pipeline

The capital and operating expenditure of the renewable gas project considers the capex and opex incurred by the biomethane plant and the JGN network. As shown in **Figure 11**, the costs of renewable gas projects can include:

- **Upfront costs** including costs associated with planning (research, concept and design, etc) and non–recurring construction or purchase and installation costs.
- **Ongoing costs** including ongoing operation and maintenance of the biomethane plant.
- **Residual value** includes the value of the plant and pipeline assets at the completion of the lifecycle or the period of analysis (see **Box 8**). This represents the benefit of the capital expenditure that has not been fully depreciated at the end of the CBA appraisal period.

Table 16 details the inputs used in the cost-benefit analysis.

Figure 11: Valuing capex and opex



Source: Frontier Economics

92 ABS (March Quarter 2024), *Consumer Price Index, Australia, TABLES 1 and 2. CPI: All Groups, Index Numbers and Percentage Changes*, https://www.abs.gov.au/statistics/economy/price-indexes-and-inflation/consumer-price-index-australia/latest-release

93 RBA, *Statement of Monetary Policy, February 2024*, https://www.rba.gov.au/publications/smp/2024/feb/pdf/statement-on-monetary-policy-2024-02.pdf

Box 8: Calculating residual value

Residual value must be estimated whenever the asset's life is:

- Shorter than the appraisal period and the business intends to dispose of the asset; or
- Greater than the appraisal period and a residual/terminal value needs to be included in the final year of the appraisal, in recognition that the asset provides value beyond the modelling period.

The residual value of an asset can be based on its value in place or its resale or scrap value less the costs of disposal (which can include expenses such as disassembly and removal, recycling or safe disposal, and/or site remediation).

This business case includes residual values of the plant and pipeline assets as the asset' lives are greater than the appraisal period. The residual values have been calculated by applying straight-line depreciation to the asset's lifespan.

Source: Frontier Economics adopted from NSW Treasury

Table 16: Capital and operating expenditure inputs

Input	Input value	Source
Total plant capex profiled over the construction period	Option 1: [redacted] ($FY2024)	JGN
Total pipeline capex including network connection costs profiled over the construction period	Option 1: [redacted] ($FY2024)	JGN
Annual plant opex	Option 1: [redacted] ($FY2024)	JGN
Plant asset life	35 years	FE assumption based on average asset lives of anaerobic digesters[94]
Pipeline asset life	50 years	FE assumption based on mains asset life from JGN PTRM[95]

Source: Frontier Economics

[94] ATO, *TR 2022/1 Income tax: effective life of depreciating assets (applicable from 1 July 2022)*, https://www.ato.gov.au/law/view/document?DocID=TXR%2FTR20221%2FNAT%2FATO%2F00007

[95] JGN Final Decision PTRM 2023-24 RoD update, https://www.aer.gov.au/system/files/JGN%20%E2%80%93%20Final%20Decision%20%E2%80%93%20PTRM%20%E2%80%93%202023-24%20RoD%20update%20%E2%80%93%20PUBLIC%2813692265.1%29.xlsm

More efficient gas supply services - avoided natural gas production and transmission costs

As shown in **Figure 12** injecting renewable gas into the gas network can reduce the demand for gas from other sources (for instance, demand for gas from gas fields in Queensland or from an LNG terminal at Port Kembla) during times of no-supply shortfall. In turn, this can defer or avoid the need to augment and/or operate gas network assets that would otherwise be required.

The deferral of this expenditure represents an economic cost saving for the community (an 'avoidable cost' benefit) relative to a Base Case.

Figure 12: The link between renewable gas and avoided gas production and transmission costs

Impact of renewable gas supply		Impact on market participants		Impact on economic value
Renewable gas displaces the need to produce and transport new gas (domestic gas or imported LNG) during times of no-supply shortfall.	→	Reduced volume of domestic gas or LNG imports will defer or avoid the need to use and/or augment gas production and transmission assets.	→	The deferral or avoidance of use and/or augmentation reduces expenditure in gas supply (resulting in an 'avoided cost' compared to the Base Case).

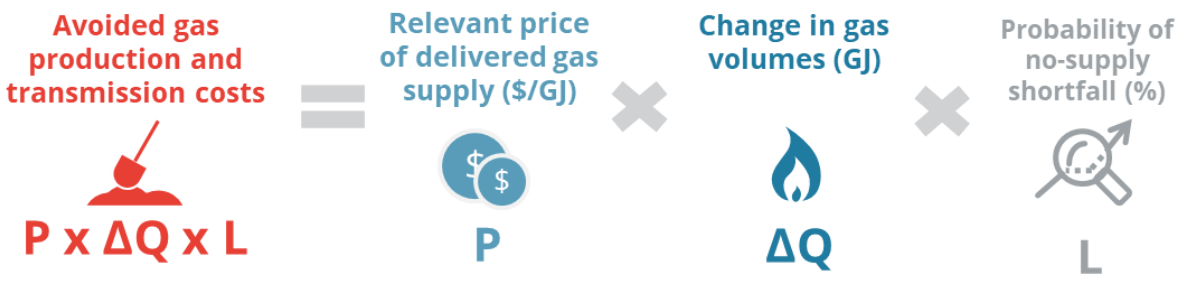
Source: Frontier Economics

As shown in **Figure 13**, the present value of this avoided natural gas production and transmission costs can be calculated by multiplying together:

- **Relevant price of delivered gas supply** (**'P'**) where estimates of the domestic market price of gas are used as a proxy for the LRMC of upstream gas supply;
- **The change in gas volume** (**'ΔQ'**) over the modelling period; and
- **The likelihood of no-supply shortfall** (**'L'**). This will be the majority of the time, since the probability of a supply shortfall is low. This is the complement of the probability of a supply shortfall, and is included in order to avoid double counting benefits with the value of gas supply resilience.

Table 17 details the inputs used in the cost-benefit analysis.

Figure 13: Valuing avoided gas production and transmission costs



Source: Frontier Economics

Table 17: Avoided natural gas production and transmission costs inputs

Input	Input value	Source
'P' – central case LRMC of gas supply	Gas market price forecast: $11.07/GJ (average over the 30-year period, $FY2024)	Gas price forecasts for AEMO's 2023 IASR and 2024 GSOO. Sydney, Step Change scenario – Industrial gas market price forecast.[96]
'P' – low case LRMC of gas supply	Gas market price forecast: $8.64/GJ (average over the 30-year period, $FY2024)	Gas price forecasts for AEMO's 2023 IASR and 2024 GSOO. Sydney, Green Energy Exports scenario – Industrial gas market price forecast.[97]
'P' – high case LRMC of gas supply	Gas market price forecast: $19.48/GJ (average over the 30-year period, $FY2024)	The forecast market price of imported LNG based on Asian LNG prices (sourced from the ACCC), LNG shipping costs (sourced from the ACCC), the estimated cost of using the Port Kembla terminal (based on public estimates of its cost) and EGP shipping costs (based on published rates).

96 AEMO (2023), *2023 Inputs Assumptions and Scenarios Consultation*, https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-iasr-assumptions-workbook.xlsx?la=en based on ACIL Allen (2023), *Natural gas price forecasts for the Final 2023 IASR and for the 2024 GSOO*, https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/acil-allen-natural-gas-price-forecasts.pdf?la=en and https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/acil-allen-natural-gas-price-forecast.xlsx?la=en

97 AEMO (2023), *2023 Inputs Assumptions and Scenarios Consultation*, https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-iasr-assumptions-workbook.xlsx?la=en based on ACIL Allen (2023), *Natural gas price forecasts for the Final 2023 IASR and for the 2024 GSOO*, https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/acil-allen-natural-gas-price-forecasts.pdf?la=en and https://aemo.com.au/-/media/files/major-publications/isp/2023/iasr-supporting-material/acil-allen-natural-gas-price-forecast.xlsx?la=en

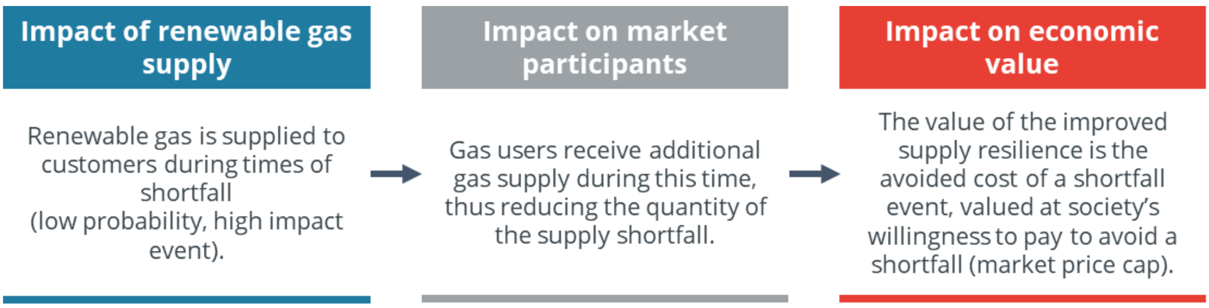
Input	Input value	Source
'ΔQ'	Option 1: [redacted] per annum	JGN
'L'	99.863% from 2025	The complement of the probability of a supply shortfall. See **Box 9**.

Source: Frontier Economics

Improved gas supply resilience – avoided costs of a gas shortfall

As shown in **Figure 14**, injecting renewable gas into the gas network can reduce the quantity of a gas shortfall during times of a supply shortfall. In turn, this relates to an economic cost saving for the community, which would otherwise have experienced an even larger shortfall in the Base Case.

Figure 14: The link between renewable gas and the avoided cost of a gas shortfall



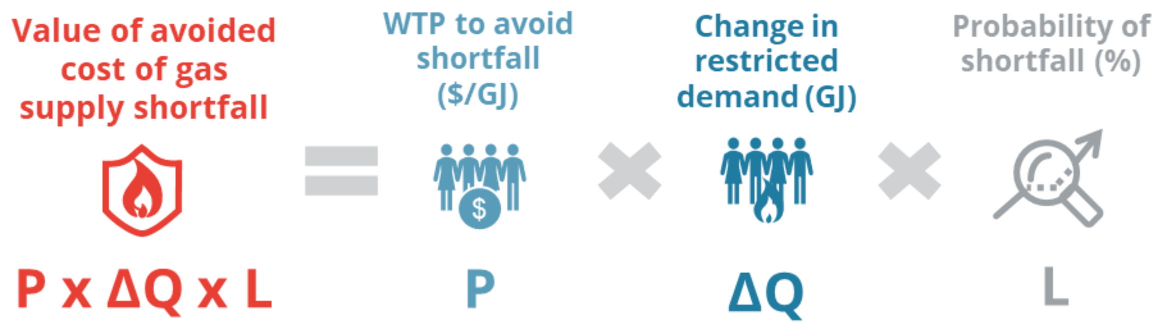
Source: Frontier Economics

As shown in **Figure 15**, the present value of this avoided cost of a gas shortfall can be calculated by multiplying together:

- **Willingness to pay to avoid shortfall** (**'P'**);
- **The change in restricted gas demand** (**'ΔQ'**) over the modelling period; and
- **The likelihood of a supply shortfall** (**'L'**). There is a non-zero probability of shortfall. See **Box 9** for the adopted assumptions. The willingness to pay to avoid shortfall applies only in times of supply shortfall. At all other times, the value avoided natural gas production and transmission costs would apply to the 'ΔQ' instead to avoid double counting benefits.

Table 18 details the inputs used in the cost-benefit analysis.

Figure 15: Valuing the avoided cost of a gas supply shortfall



Source: Frontier Economics

Table 18: Avoided cost of a gas shortfall inputs

Input	Input value	Source
'P' – willingness to pay to avoid a gas supply shortfall	$400.00/GJ ($FY2024)	Valued at the market price cap (STTM)[98]
'ΔQ' – the change in restricted demand	Option 1: [redacted] per annum	JGN
'L' – the probability of a gas supply shortfall	Low case: 0.014% from 2025 Central case: 0.137% from 2025 High case: 0.274% from 2025	See **Box 9**.

Source: Frontier Economics

Box 9: The probability of a gas supply shortfall

There is a non-zero probability of a gas supply shortfall. However, it is uncertain what the probability of shortfall is given the uncertainty of future investment, particularly the investment in future gas import terminal projects and uncertainty in future demand levels. Therefore, we have assumed conservative values for the probability based on AEMO's 2024 Gas Statement of Opportunities' actual daily southern gas system adequacy since

98 AEMO (2023), *Review of the Gas Market Parameters for the DWGM and STTM*, p. 2, accessed 23 October 2023, https://aemo.com.au/-/media/files/stakeholder_consultation/consultations/gas_consultations/2023/gas-market-parameter-review-2022/aemo---final-determination---gas-market-parameters-review-2022.pdf?la=en

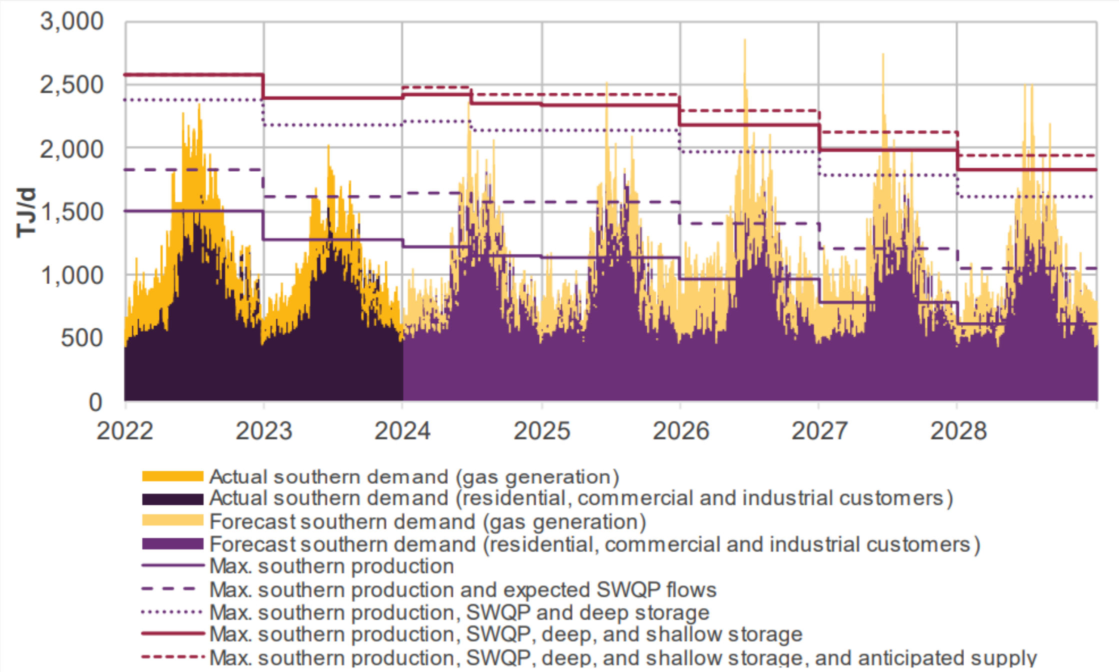
January 2022, and forecast to 2028 using existing, committed and anticipated projects (**Figure 16**).

AEMO is forecasting near term shortfalls on 1-in-20 peak days (i.e. 5% POE). If we multiply the proportion of days with shortfall by probability (i.e. 1-in-20) we get an estimate of number of days that biomethane supply avoids shortfall. We have adopted this using 2025 as the low case.

AEMO's 1-in-2 peak day forecasts (i.e. 50% POE, not shown here) are 5-10% lower than 1-in-20. In 2026 this suggests that there will be shortfalls even on 1-in-2 peak days (for one or two days). We have adopted this for the central and high cases.

The calculations are show in **Table 19** below.

Figure 16: Actual daily southern gas system adequacy since January 2022, and forecast to 2028 using existing, committed and anticipated projects (TJ/d)



Note: Actual maximum southern production and SWQP flow rates are shown for 2022 and 2023.

Source: AEMO (2024), Gas Statement of Opportunities, p. 63, https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2024/aemo-2024-gas-statement-of-opportunities-gsoo-report.pdf?la=en

Table 19: Assumed probability of gas supply shortfall each year from 2025

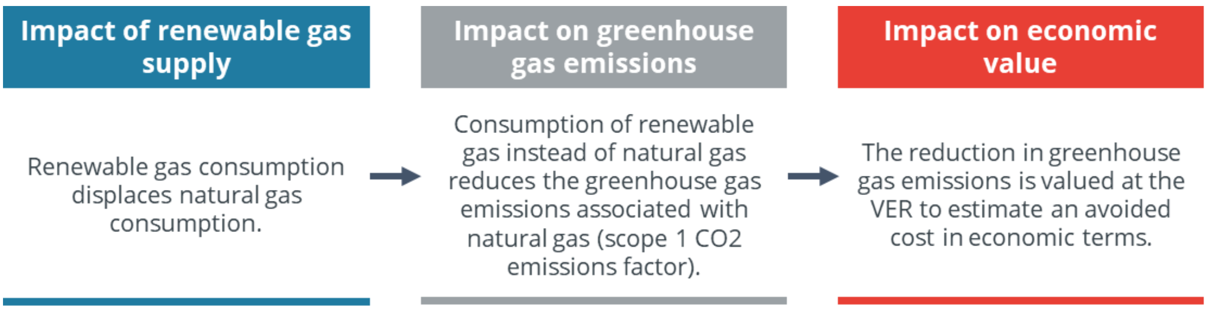
Scenario	POE	Number of days per year of shortfall	Assumed probability of shortfall[99]
Low	5%	1	0.014%
Central	50%	1	0.137%
High	50%	2	0.274%

Source: Frontier Economics

Economic value of changes to Australia's greenhouse gas emissions - avoided GHG emissions

As shown in **Figure 17**, injecting renewable gas into the gas network reduces the consumption of natural gas. In turn, this reduces greenhouse gas emissions associated with natural gas, as the greenhouse gas emissions from [redacted] anyway in the Base Case. The economic value of these changes to Australia's greenhouse gas emissions can be estimated by valuing the avoided GHG emissions using the scope 1 CO2 emissions factor and AER published VER.

Figure 17: The link between renewable gas and avoided greenhouse gas emissions costs



Source: Frontier Economics

As shown in **Figure 18**, the present value of these avoided greenhouse gas emissions costs can be calculated by multiplying together:

- **The value of emissions reduction** (**'P'**); and
- **The change in greenhouse gas emissions** (**'ΔQ'**) over the modelling period.

99 E.g. the calculation for the central case is $50\% \times \frac{1}{365} = 0.137\%$

We note that to quantitatively calculate the change in greenhouse gas emissions, we have only considered the change in scope 1 emissions from natural gas displacement at 51.4 kg CO2-e/GJ (see **Table 21**) and have considered all other changes qualitatively. This is due to the uncertainty as to how to calculate the additional scope 3 and other emissions.

Table 20 sets out the potential scope 3 emission sources following the categories reported in Appendix 3 of the Australian National Greenhouse Accounts Factors[100], our assessment of the likely impact of the greenhouse gas emissions and our rationale.

In conclusion, we have not included the National Greenhouse Accounts Factors estimates of scope 3 emissions (i.e. 13.1 kg CO2-e/GJ for metro NSW and 14.0 kg CO2-e/GJ for non-metro NSW),[101] nor any other values, due to uncertainty of scope 3 emissions for these projects where total emissions could be higher or lower.

Table 21 details the inputs used in the cost-benefit analysis.

[100] DCCEEW (2023), *Australian National Greenhouse Accounts Factors*, p. 48, https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-account-factors-2023.pdf

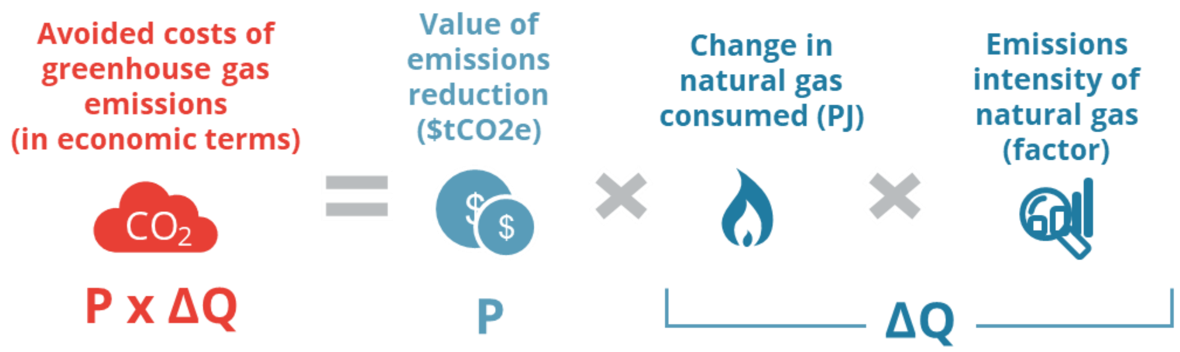
[101] DCCEEW (2023), *Australian National Greenhouse Accounts Factors*, p. 17, https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-account-factors-2023.pdf

Table 20: Greenhouse gas emissions factor – scope 3

Scope 3 emission source	Likely impact of GHG emissions	Rationale
Natural gas exploration	Reduction	As the biomethane injected into the distribution network is displacing natural gas, additional natural gas exploration would not be needed, therefore its corresponding emissions would also be avoided.
Natural gas production or processing	Unclear	Fuel combustion and fugitive emissions associated with natural gas production or processing would be avoided. However, there will be emissions from biomethane projects, such as the transportation of feedstock, energy use of the plant and fugitive emissions from the plant. This would also include avoided emissions from feedstock/waste disposal processes no longer being needed and any emissions reductions attributable to the co-products, digestate and food/industrial grade CO2 produced (e.g. emissions reduction potentials due to the use of animal excrements and organic waste streams as biogas substrates and the replacement of industrial chemical fertilisers by digestate), which can be offset against whatever emissions are created from energy used in the biomethane plant.
Natural gas transmission	Reduction	As biomethane is being injected directly into the distribution network, emissions related to transmission are expected to be avoided.
Natural gas distribution	Unclear	Natural gas distribution might be higher or lower, depending on whether these new projects increase the need for compression (or increase fugitive emissions due to leaks) or decrease the need for compression (or decrease fugitive emissions due to leaks).

Source: Frontier Economics

Figure 18: Valuing avoided greenhouse gas emissions costs



Source: Frontier Economics

Table 21: Avoided greenhouse gas emissions costs inputs

Input	Input value	Source
'P' – low case value of emissions reduction	VER (-25%): $52.50 / tonne CO2-e in 2024 ($FY2023), escalated by CPI+~7%	The average of the IPCC & ACCU prices as per the interim AER draft guidance, March 2024[102]
'P' – central case value of emissions reduction	VER: $70.00 / tonne CO2-e in 2024 ($FY2023), escalated by CPI+~7%	The average of the IPCC & ACCU prices as per the interim AER draft guidance, March 2024
'P' – high case value of emissions reduction	VER (+25%): $87.50 / tonne CO2-e in 2024 ($FY2023), escalated by CPI+~7%	The average of the IPCC & ACCU prices as per the interim AER draft guidance, March 2024
'ΔQ' – the change in greenhouse gas emissions	Using 51.4 kg CO2-e/GJ: Option [redacted]	Calculated from the change in natural gas consumed and the scope 1 combined gases emission factor for natural gas distributed in a pipeline (51.53 kg CO2-e/GJ) net of the scope 1 combined gases emissions factor for biomethane (0.13 kg

102 AER (2024), *Valuing emissions reduction AER draft guidance*, https://www.aer.gov.au/system/files/2024-03/AER%20-%20Valuing%20emissions%20reduction%20draft%20guidance%20-%20March%202024.pdf

		CO_2-e/GJ) resulting in a factor of **51.4 kg CO_2-e/GJ**.[103].
Change in natural gas consumed	Option 1: [redacted] per annum	JGN

Source: Frontier Economics

[redacted]

As shown in

Figure 20, the [redacted] for other purposes can be calculated by multiplying together:

- **The market value of biogas ('P'**); and

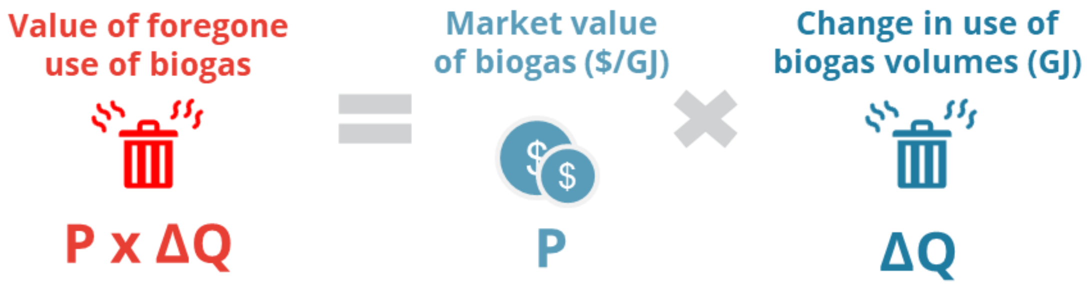
[103] DCCEEW (2023), *Australian National Greenhouse Accounts Factors*, p. 17, https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-account-factors-2023.pdf

[104] NSW Treasury (2023), *TPG23-08 NSW Government Guide to Cost-Benefit Analysis*, p 48. https://www.treasury.nsw.gov.au/sites/default/files/2023-04/tpg23-08_nsw-government-guide-to-cost-benefit-analysis_202304.pdf

- **The change in the volume of biogas used to provide biomethane** (**'ΔQ'**) over the modelling period.

Table 22 details the inputs used in the cost-benefit analysis.

Figure 20: Valuing the foregone use of biogas



Source: Frontier Economics

[redacted]

Input	Input value	Source
[redacted]		

[redacted]

Input	Input value	Source
[redacted]		

Source: Frontier Economics

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