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JGN Renewable Gas Projects – Response to AER Draft Decision

A technical note for Jemena Gas Networks | January 2025

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Executive Summary

Context

JGN Access Arrangement proposal – Renewable gas Business Cases

Jemena Gas Network (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.

JGN is proposing to connect eight renewable gas projects, from a mixture of [redacted] sites across NSW to enable 7 PJ pa of biomethane to be injected into the Jemena gas network by 2030. These projects are designed to support customer and community expectations to manage the carbon emissions from the supply and consumption of natural gas by customers including the 'hard to abate' customer groups where electrification as a means of managing carbon may not be practical.

Frontier Economics has supported JGN in developing eight business cases covering each of the eight renewable gas projects across NSW, involving cost-benefit analysis to demonstrate that the capex is justifiable through a positive 'overall economic value' consistent with National Gas Rules (NGR) 79(2)(a), and calculated in accordance with Rule 79(3). As there is no published AER guidance on CBA for the gas sector, the business cases developed a CBA approach whereby the economic value accruing to JGN (as service provider), gas producers, users and end users was calculated:

- Consistent with the broad principles and techniques in standard CBA guidelines, including the AER's Cost-benefit analysis ISP guidelines[1];
- 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 as well as in qualitative terms, accruing to JGN (as service provider), gas producers, users and end users;
- Undertaking sensitivity analysis on key assumptions to understand the impact of uncertainty over the 30-year modelling period on the overall economic value of the projects.

Across each of the eight business cases, the CBAs showed a positive economic value (NPV>0; BCR>1) from the project cases driven by the incremental *benefits* from renewable gas – in the form of the avoided costs of gas production and transmission costs from natural gas sources, the avoided costs of a gas supply shortfall and the avoided cost of greenhouse gas emissions from the displacement of natural gas consumption – outweighing the *costs* of producing renewable gas – in the form of pipeline and plant expenditure as well as any other opportunity costs from use of the waste resources.

[1] 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

These business cases were submitted to the AER as part of JGN's Access Arrangement Proposal that sought recovery from customers of the pipeline capex related to these eight renewable gas projects. The CBA models for each project containing inputs, calculations and results were also submitted to the AER.

AER Draft Decision

The AER's draft decision is not to approve the JGN pipeline capital expenditure. The AER stated that:

- the business cases did not demonstrate compliance with National Gas Rules (NGR) 79(2)(a), primarily on the basis that the Base Case 'counterfactual' for the CBA at each of the eight project sites did not adequately account for the potential for the waste resource (biogas or other resources) to be used for the production of renewable electricity.
- further information on key modelling input assumptions and their impacts on the CBA results was required, and without further information and analysis the AER "do not consider the projects are justifiable under clause 79(2)(a) of the NGR or likely to be efficient."[2]

The AER noted that it had not previously considered the application of Rule 79(3) when determining whether the overall economic value of the expenditure is positive and therefore justifiable under clause 79(2)(a) of the NGR.

Scope & approach

The objective of this technical note is to assist the AER by providing further information on the impact of the alternative counterfactuals and assumptions on the estimate of overall economic value from each of the eight renewable gas projects.

JGN has requested Frontier Economics provide updated CBA modelling for each of the eight renewable gas projects including:

- Defining an alternative waste to electricity counterfactual which utilises the feedstock and biogas for electricity generation, and comparing this to the project cases to identify "whether the biomethane production is the most efficient use of the feedstock".[3] This scenario analysis will be undertaken consistent with the broad principles and techniques in standard CBA guidelines, including the principle of 'internal consistency'[4] which requires the analysis to incorporate the costs incurred by *electricity service providers, producers, users and end users* to generate electricity and connect to market as well as the benefits received *by electricity service providers, producers, users and end users* including the economic value of changes to greenhouse gas emissions *in the electricity sector*, relative to the project option.
- Documenting key assumptions, including the basis and rationale for the assumptions adopted in the business cases (including updated estimates of the value of avoided gas supply and transportation costs) and alternative assumptions utilised in this technical note. For example, assumptions related to electricity generation have where possible utilised publicly available information including published by Commonwealth Government agencies including AEMO, CSIRO and DCCEEW (Australian National Greenhouse Accounts Factors).

2 AER, draft decision: JGN access arrangement 2050 to 2030: Attachment 5- Capital expenditure, November 2024, p28.

3 AER, draft decision: JGN access arrangement 2050 to 2030: Attachment 5- Capital expenditure, November 2024, p28.

4 NSW Treasury (2023), *TPG23-08 NSW Government Guide to Cost-Benefit Analysis*, p. 80. https://www.treasury.nsw.gov.au/sites/default/files/2023-04/tpg23-08_nsw-government-guide-to-cost-benefit-analysis_202304.pdf

- Undertaking sensitivity analysis by modelling the impact of alternative assumptions on the overall economic value of the projects, utilising the Business Case base case (base case) and alternative waste to electricity counterfactual, including the following assumptions:
  - an alternative estimate of the value of avoided gas supply and transportation costs (incl. AEMO 2025 Draft IASR);
  - an alternative estimate of the value of biogas (opportunity cost from producing biomethane or electricity);
  - a shorter modelling period, incl. removal of the residual value of plant (biogas, biomethane and electricity) and pipeline assets, to reflect risk related to long-term availability of feedstock;
  - an alternative lower estimate of the value of digestate and food grade CO_2.

The approach is to leave *all other* modelling processes and assumptions unchanged from the business cases submitted to the AER.

Summary of results

Table 1: **Summary of CBA modelling: Incremental value of project options under Original Base Case vs Alternative waste to electricity counterfactual (central case) ($m, $FY2024, NPV)**

	Business Case results – incremental value of project options compared to original Base Case (June 24)	Updated results – incremental value of project options compared to alternative waste to electricity counterfactual * (Dec 24)
Lilli Pilli	[redacted]	[redacted]
Kauri	[redacted]	[redacted]
Blue Gum	[redacted]	[redacted]
Red Gum	[redacted]	[redacted]
Huon Pine	[redacted]	[redacted]
Iron Bark	[redacted]	[redacted]
Coolabah	[redacted]	[redacted]

Wollemi	[redacted]

Source: Frontier Economics

*Note: * Incremental costs and benefits of the Project Options, compared to the waste to electricity counterfactual for each of the eight sites. This includes the costs incurred by electricity service providers, producers, users and end users to generate electricity and connect to the market as well as the benefits received including the economic value of changes to greenhouse gas emissions in the electricity sector, relative to the project option involving biomethane production.*

Table 2: Summary of CBA modelling: Incremental value of project options under 2024 AEMO gas price forecast ($11.07/GJ) vs 2025 AEMO Draft IASR ($12.41/GJ) ($m, $FY2024, NPV)

	Business Case results – incremental value of project options compared to original Base Case ($11.07/GJ) * (June 24)	Updated results - incremental value of project options compared to original Base Case ($12.41/GJ) ** (Dec 24)	Updated results – incremental value of project options compared to alternative waste to electricity counterfactual ($12.41/GJ) ** (Dec 24)
Lilli Pilli	[redacted]		
Kauri			
Blue Gum			
Red Gum			
Huon Pine			
Iron Bark			
Coolabah			
Wollemi			

Source: Frontier Economics

*Note: * To value the avoided costs of gas production and transportation the original Business Cases (central case) assumed an average of $11.07/GJ over the 30-year period, $FY2024) from AEMO's 2023 IASR and 2024 GSOO. Sydney, Step Change scenario – Industrial gas market price forecast.*

*Note: ** Assumes an average of $12.41/GJ over the 30-year period, $FY2024) from AEMO 2025 Draft IASR.*

Table 3: Summary of CBA modelling: Incremental value of project options under original value of biogas at landfill sites [redacted] vs alternative value of biogas [redacted] ($m, $FY2024, NPV)

	Business Case results – incremental value of project options compared to original Base Case ($2.06/GJ) (June 24)	Updated results - incremental value of project options compared to original Base Case ($6.21/GJ) * (Dec 24)	Updated results – incremental value of project options compared to alternative waste to electricity counterfactual ($6.21/GJ) ** (Dec 24)
Lilli Pilli	[redacted]		
Kauri			

Source: Frontier Economics

*Note: * This alternative value of biogas of [redacted]s derived assuming a levelised cost of [redacted] and costs of a reciprocating generator.*

*Note: ** The value of biogas of [redacted] is used for both the alternative counterfactual and the project options i.e. the same cost of feedstock to produce electricity and biomethane, meaning there is no incremental cost of feedstock under the project option.*

Table 4: Summary of CBA modelling: Incremental value of project options under original modelling period (30 years) vs shorter modelling period (24 years) ($m, $FY2024, NPV)

	Business Case results – incremental value of project options compared to original Base Case (30 years) (June 24)	Updated results - incremental value of project options compared to original Base Case (24 years) * (Dec 24)	Updated results – incremental value of project options compared to alternative waste to electricity counterfactual (24 years) ** (Dec 24)
Lilli Pilli	[redacted]		
Kauri			
Blue Gum			

Red Gum	[redacted]
Huon Pine	
Iron Bark	
Coolabah	
Wollemi	

Source: Frontier Economics

*Note: * Note: This assumes a modelling period of 2024 to 2047 (24 years, incl. biomethane production of up to 20 years) and no residual value of plant and pipeline assets. This represents a scenario where there may be risks to long-term access to feedstock that cannot be managed, and the plant and pipeline assets provide no further value beyond 2047.*

*Note: ** Incremental costs and benefits of the Project Options, compared to the waste to electricity counterfactual for each of the eight sites over a modelling period of 2024 to 2047 (24 years).*

Table 5: Summary of CBA modelling: Incremental value of project options under original value of digestate and food grade CO2 at non-landfill sites vs. lower alternative value (20% lower) ($m, $FY2024, NPV)

	Business Case results (Original Base Case by-products valued at central case) * (June 24)	Updated results (Original Base Case, by-products valued at 20% lower than central case) ** (Dec 24)	Updated results – (alternative counterfactual, by-products valued at 20% lower than central case) ** (Dec 24)
Blue Gum	[redacted]		
Red Gum			
Huon Pine			
Iron Bark			

Coolabah	[redacted]	

Source: Frontier Economics

[redacted]

Findings

#	Finding
Key Finding 1	**Significant investment in electricity-related infrastructure is required to produce electricity from waste resources.** These costs accrue to electricity service providers, producers, users and end users. Apart from the investment in new biogas production capacity which is required to produce electricity or biomethane at the non-landfill sites (and is no longer an incremental cost under the project option), the other costs of investment and operation of infrastructure to produce electricity at these sites are avoided under the project case (i.e. are a project benefit) This is a significant positive driver of the economic value of the project cases, compared to the alternative counterfactual.
Key Finding 2	**Using biogas as a source of electricity (alternative counterfactual) is *not* an efficient way of generating electricity in terms of GHG emissions (valued under the VER).** For all sites (except Lilli Pilli) the economic value of GHG emissions associated with the production of electricity from biogas at these eight sites outweigh the value of the GHG emissions associated with the production of electricity from other generators in the NEM over the modelling period**.** This net cost that would otherwise accrue to electricity service providers, producers, users and end users is avoided under the project case (i.e. a project benefit) This is a small positive driver of the economic value of the project cases, compared to the alternative counterfactual.

#	Finding
Key Finding 3	**Using biogas as a source of electricity (alternative counterfactual) prevents decarbonisation of 'hard to abate' demands in the gas sector.** GHG emissions are associated with the consumption of natural gas over the modelling period. A significant portion of these costs are avoided under the project case when approx. 7PJ pa of biomethane substitutes for natural gas[5] (i.e. a project benefit). [redacted] under the VER over the modelling period. These incremental benefits accrue to gas service providers, producers, users and end users. This is a significant positive driver of the economic value of the project cases, compared to the alternative counterfactual.
Key Finding 4	All project options produce a positive NPV and BCR using the alternative counterfactual. For the central case, the NPVs and BCRs for: • [redacted] are marginally higher than those using the Base Case from the Business Case • [redacted] are significantly higher than those using the Base Case from the Business Case The increase in the estimate of overall economic value when comparing the project options to the alternative counterfactual is primarily driven by the minimal change in the economic value of emissions in the electricity sector when utilising the feedstock for biomethane, and for the [redacted] the significant investment in electricity-related infrastructure (including biogas facilities) required to produce electricity from waste resources (i.e. lowering the incremental costs of producing biomethane under project options). This analysis shows the project options ***are*** "genuinely facilitating a more efficient use of the feedstock for emissions reduction" and are ***not*** "simply transferring emissions reduction from one sector to another"[6] Most are higher than the original base case, showing that using biogas as a source of electricity (Base Case) over the forecast period is not an efficient way of generating electricity in terms of GHG emissions and the cost of electricity generation.

5 Noting that gas demand over the modelling period is forecast to significantly exceed the production of 7PJ pa of biomethane from the eight sites.

6 AER, draft decision: JGN access arrangement 2050 to 2030: Attachment 5- Capital expenditure: Confidential Appendix D, November 2024.

#	Finding
Key Finding 5	AEMO 2025 Draft ISAR forecast of industrial gas prices from ACIL Allen provides an updated estimate for the value of avoided gas production and transport costs. These estimates represent the best available and publicly verifiable forecast of the costs (or avoided costs) of gas production and transport costs. These estimates are slightly higher than those assumed in the Business Case (central case) over the modelling period. All project options, under both the original Base Case and alternative counterfactual, produce a larger NPV and BCR using these updated estimates of forecast of industrial gas prices.
Key Finding 6	Reductions in the costs of supply (or avoided costs) represent a resource 'benefit' and not a surplus or transfer between parties. For this reason, they are relevant to the CBA and the assessment of positive 'overall economic value' consistent with National Gas Rules (NGR) 79(2)(a), and calculated in accordance with Rule 79(3).
Key Finding 7	Using a lower value for avoided gas production and transport costs (based on AEOM's Green Energy Exports scenario rather than AEMO's Step Change scenario, reduces the benefits of the project options. However, project options still provide a positive overall economic value (NPV>0; BCR>1).
Key Finding 8	Utilising a higher value of biogas lowers the estimate of economic value for the [redacted] when comparing the project option to the original Base Case. However, both sites still provide a positive overall economic value (NPV>0; BCR>1) However, utilising this higher value of biogas for the [redacted]: • does not change the estimate of the overall economic value for [redacted] sites when comparing the project option to the alternative counterfactual. All else equal, a higher value of biogas increases the costs of producing electricity and biomethane; • risks using estimates of the value of biogas that are not supported by other available market evidence (i.e. there is limited to no evidence that market participants are willing to purchase biogas at these prices to produce electricity, biomethane or SAF).
Key Finding 9	A shorter modelling period reduces the incremental costs and benefits of the project options, and the overall estimate of economic value. However, project options at all sites still provide a positive overall economic value (NPV>0; BCR>1) under both the original base case and alternative counterfactual in the unlikely scenario that there is no access to feedstock beyond 2047 and no value to these assets i.e. economic life is less than design life, and there is 'no' scrap value.

#	Finding
Key Finding 10	A 20% lower value of digestate reduces the benefits of the project options, and the overall estimate of economic value for the [redacted] sites when compared to the original base case. However, project options at these sites still provide a positive overall economic value (NPV>0; BCR>1). It does not impact the overall estimate of economic value for [redacted] sites when compared to the alternative counterfactual given digestate as a by-product is a 'benefit' for electricity and biomethane production (i.e. there is no incremental change between counterfactual and project option).
Key Finding 11	A 20% lower value of food/industrial grade CO2 reduces the benefits of the project options, and the overall estimate of economic value for the [redacted] sites when compared to the original base case and alternative counterfactual. However, project options at these sites still provide a positive overall economic value (NPV>0; BCR>1).

Conclusion

Based on this analysis presented in this technical note we conclude that waste to electricity is not a credible counterfactual for the project options given:

- The NGR 79(2)(a) and 79(3) are focused on the economic value accruing to JGN (as service provider), gas producers, users and end users, rather than electricity service provider, electricity producers, users and end users (i.e. not designed to account for both gas and electricity market impacts);
- Even if accounting for both gas and electricity market impacts, the incremental value of the project options is larger when assuming waste to electricity is the counterfactual, relative to the original base case. This suggests there is more value to the community from alternative use or disposal of waste resources rather than electricity generation. This is likely reflected in the feedback from renewable gas proponents.

For this reason, the Base Case in the business cases remains the appropriate counterfactual.

When accounting for the 'new' sensitivities tested on the original Base Case, including shorter asset life and lower value of digestate and food grade CO2, each of the project options for each of the eight sites still produced a positive overall economic value is positive (NPV>0; BCR>1), calculated in accordance with Rule 79(3).

We conclude that the project options for each of the eight sites are justified under Rule 79(2)(a) of the National Gas Rules.

1 Alternative counterfactual

The business cases assumed a 'no investment in renewable gas' (Base Case), where in the absence of this investment to connect renewable gas producers to market, some variation of the status quo would continue.

For [redacted] the business case noted:

> *"continuing to use biogas from the* [redacted] *for purposes other than production of renewable gas (biomethane) for use by end gas customers. While it is unclear how this biogas would be used (electricity, SAF etc) this biogas has a value (reflected in the market price of biogas), which can be considered to represent the opportunity cost of using biogas to produce biomethane."*[7]

For [redacted] the business case noted

> *We have assumed in the absence of this investment, the status quo would continue which is the continuation of the business-as-usual agricultural waste practices: primarily burning of agricultural waste or disposal in landfill.*[8]

The AER has indicated that the business cases did not demonstrate compliance with National Gas Rules (NGR) 79(2)(a), primarily on the basis that the Base Case 'counterfactual' at each of the eight project sites did not adequately account for the *potential* for the waste resource (biogas or other resources) to be used to produce renewable electricity.

The objective of this section is to assist the AER by providing further information on the impact of the alternative counterfactuals on the estimate of economic value from each of the eight renewable gas projects.

1.1 Key assumptions

1.1.1 Costs of electricity generation

To address the AER's concerns we have defined an alternative counterfactual whereby the waste resource is used to produce renewable electricity at each of the eight sites. This would require different levels of investment at each site to generate electricity from the waste resources. As summarised in [redacted], the alternative counterfactual assumes investment in:

[redacted]

The size of the investments and ultimately the cost of investment at each site has been derived from the estimate of biogas availability, which in turn was derived from the estimate of annual biomethane production sourced by JGN.

7 Frontier Economics, Lilli Pilli Renewable Gas Project – Business Case, Report for Jemena Gas Networks, June 2024.

8 Frontier Economics, Red Gum Renewable Gas Project – Business Case, Report for Jemena Gas Networks, June 2024.

[redacted]

[redacted]

The costs of these investments as well as the ongoing operating costs, accrue to electricity service providers, producers, users and end users. Apart from the investment in new biogas production capacity which is required to produce electricity or biomethane at the [redacted], the other costs of electricity-related infrastructure to produce electricity at these sites are avoided under the project case (i.e. an incremental project benefit). For this reason, under the project case the incremental benefits in terms of avoided biogas to electricity costs that accrue to electricity service providers, producers, users and end users are relatively large.

However, under the project case there are additional electricity related costs, including operating and fuel costs, from existing generators in the NEM. These costs are incurred as renewable electricity generation that would otherwise occur at each of the eight sites is 'lost' under the project case where the feedstock is used to produce biomethane and instead, electricity demand will be met by the other electricity generation assets in the NEM. This involves an increase in electricity generation costs (as well as an increase in emissions – discussed in the next section). Similar to GHG emissions, these operating and fuel costs of electricity generation from other generation assets in the NEM (sourced from AEMO's 2024 ISP[9]) are rapidly decreasing as a result of a shift to renewable generation that does not have a fuel cost or variable operating costs (see Figure 2). For this reason, under the project case the incremental costs in terms of additional costs in the NEM that accrue to electricity service providers, producers, users and end users are relatively small.

To calculate these incremental costs and avoided costs (or benefits) consistent with standard CBA principles we have adopted the assumptions set out in Table 6 below. Where possible we have sought to utilise publicly available information including published by Commonwealth Government agencies including AEMO, CSIRO and DCCEEW (Australian National Greenhouse Accounts Factors).

[9] AEMO 2024, 2024 Integrated System Plan (ISP), 2024 ISP generation and storage outlook, Core, 2024 ISP - Step Change – Core, Based on CDP3 NSW generation volumes and costs, available from: https://aemo.com.au/-/media/files/major-publications/isp/2024/supporting-materials/2024-isp-generation-and-storage-outlook.zip?la=en

Table 6: **Key electricity generation cost input assumptions for alternative counterfactual**

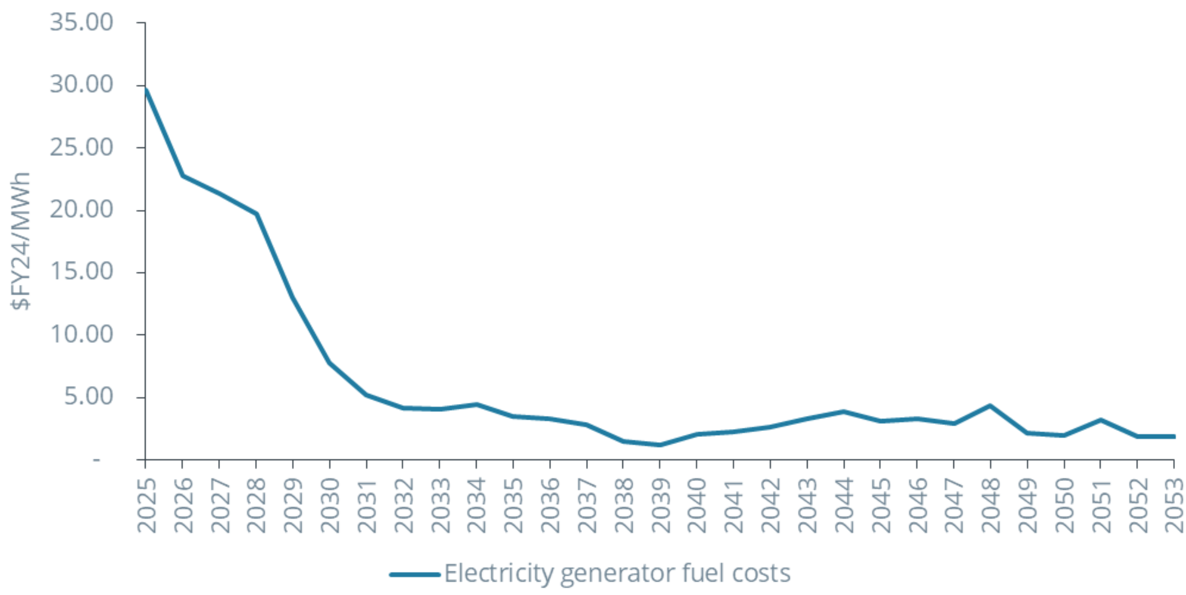
Key input assumption	Value (all figures in $FY24)	Source
Heat rate	11.87 GJ/MWh	US EPA for a Standard Reciprocating Engine-Generator Set for landfill gas energy recovery projects (converted from 11,250 Btu/kWh)[10]
Capital cost of biogas to electricity generation	$1,980/kW 25 year asset life	CSIRO GenCost 2024-25
Operating cost of biogas to electricity generation	Fixed cost of $29.4/kW pa Variable cost of $8.50/MWh pa	CSIRO GenCost 2024-25
Fuel cost of biogas to electricity generation*	$6.21/GJ (updated assumption); $2.06/GJ (original assumption)	Based on levelised cost of $108.88/MWh
Operating and fuel costs of electricity generation from grid	2028: $19.70/MWh, 2035: $3.45/MWh, 2047: $2.91/MWh See Figure 2	AEMO 2024 ISP Calculated based on fuel costs and variable operating costs for coal and gas plant forecast to be operating in NSW each year, divided by total electricity production forecast in NSW each year. Using Step Change results from 2024 ISP.
Electricity network connection capex[11]	$85.54/kW	AEMO 2023 IASR

Source: Frontier Economics

[10] United States EPA 2023, Landfill Gas Energy Cost Model (LFGcost-Web) User's Manual, p. 33, accessed 11 December 2024, available at: https://www.epa.gov/system/files/documents/2023-09/lfgcost_web_v3.6_usersmanual_sep2023.pdf

[11] Lilli Pilli has assumed no electricity network connection capital expenditure. Kauri has assumed an electricity network connection capital expenditure of $42.77/kW.

Figure 2: Avoided cost of electricity generation in the NEM under alternative counterfactual (biogas to electricity)



Source: AEMO 2024, 2024 Integrated System Plan (ISP), 2024 ISP generation and storage outlook, Core, 2024 ISP - Step Change - Core

1.1.2 Changes in GHG emissions from electricity generation

GHG emissions are associated with the consumption of natural gas over the modelling period.

The business cases accounted for the economic value of GHG emissions that are avoided under the project case when approx. 7PJ pa of biomethane substitutes for natural gas.[12] [redacted] under the VER over the modelling period. These incremental benefits accrue to gas service providers, producers, users and end users.

However, the AER stated that:

> [redacted]

The AER seems to be asking whether the:

- benefits from reduced GHG emissions in the gas sector from the use of feedstock for production of biomethane under the project case [redacted] are offset by the
- costs of increased GHG emissions in the electricity sector from feedstock no longer being available to produce renewable electricity under the project case, requiring electricity demand to be met by the other electricity generation assets in the NEM.

[12] Noting that gas demand over the modelling period is forecast to significantly exceed the production of 7PJ pa of biomethane from the eight sites.

[13] AER, draft decision: JGN access arrangement 2050 to 2030: Attachment 5- Capital expenditure: Confidential Appendix D, November 2024, p1.

Identifying the change in GHG emissions in the electricity sector from biogas being used for biomethane rather than electricity requires estimating the:

- GHG emissions in the electricity sector from demand being met by other generation assets in the NEM (under the project case renewable electricity at the eight sites is 'lost' and electricity demand is met by other assets). This is a function of the forecast change in emissions intensity of electricity assets in the NEM. As shown in Table 7 and Figure 3, AEMO forecasts the emissions intensity of electricity assets to fall rapidly.
- GHG emissions from production of electricity from biogas at each of the eight sites (i.e. biogas to electricity is not emissions 'free'). As shown in Table 7 and Figure 3, this is assumed to be flat over the period such that it is below the emissions intensity of other electricity assets in the NEM initially, and then above the emissions intensity of other electricity assets in the NEM initially by the mid-2030s.

Table 7: Key electricity generation GHG emissions input assumptions for alternative counterfactual

Key input assumption	Value (all figures in $FY24)	Source
Heat rate	11.87 GJ/MWh	US EPA for a Standard Reciprocating Engine-Generator Set for landfill gas energy recovery projects (converted from 11,250 Btu/kWh)[14]
Greenhouse gas emissions factor - biogas to electricity generation	6.43 kg CO-e/GJ equivalent to 0.08 tonnes CO2-e/MWh (using heat rate of 11.87 GJ/MWh)	DCCEEW 2024, Australian National Greenhouse Accounts Factors, Landfill biogas that is captured for combustion (methane only), p. 17.[15]
Greenhouse gas emissions factor - electricity generation from grid (displace average emissions intensity)	2028: 0.39 tonnes CO2-e/MWh, 2035: 0.04 tonnes CO2-e/MWh 2047: 0.02 tonnes CO2-e/MWh See Figure 3	Total emissions from AEMO 2024 ISP and total demand from AEMO 2024 ESOO

Source: Frontier Economics

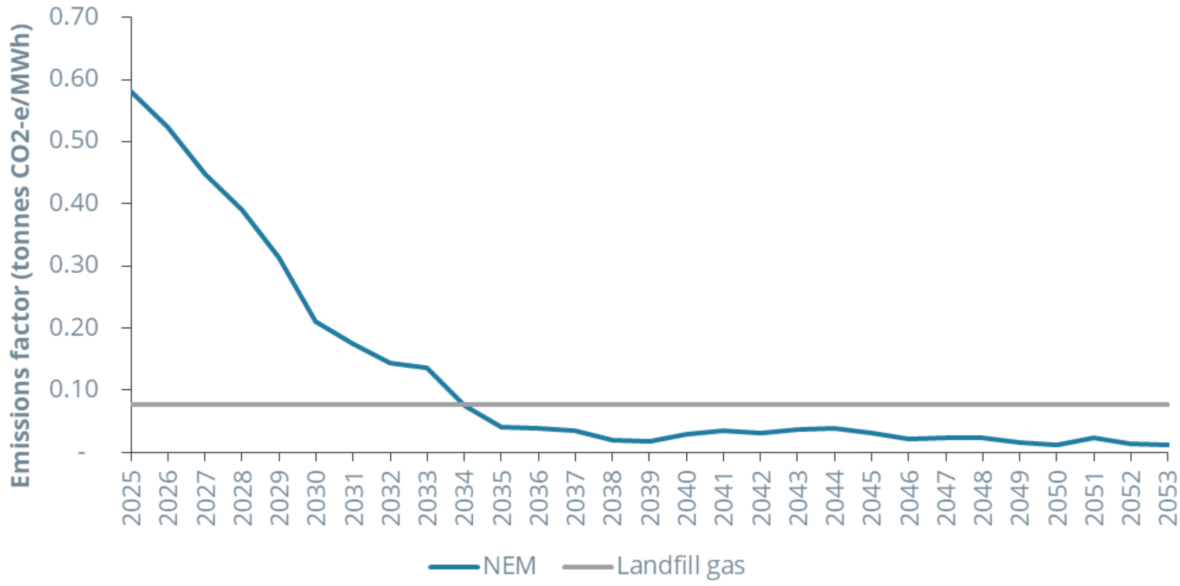
[14] United States EPA 2023, Landfill Gas Energy Cost Model (LFGcost-Web) User's Manual, p. 33, accessed 11 December 2024, available at: https://www.epa.gov/system/files/documents/2023-09/lfgcost_web_v3.6_usersmanual_sep2023.pdf

[15] Available at: https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-account-factors-2024.pdf

The emissions factor of the NEM has been calculated by dividing the total forecast emissions of the NEM (sourced from AEMO's 2024 ISP[16]) by the total forecast demand of the NEM (sourced from AEMO's 2024 ESOO[17]).

[redacted] emissions factor is based on a heat rate of 11.87 GJ/MWh and a greenhouse gas emissions factor [redacted] biogas to electricity generation of 6.43 kg CO-e/GJ. This represents a cost in the alternative base case and a benefit in the project option.

Figure 3: GHG emissions from electricity generation under alternative counterfactual (biogas to electricity) vs project case (biogas to biomethane)



Source: Frontier Economics

Table 8 shows that over the 30-year modelling period, for most sites the first factor is outweighed by the second factor.[18] That is, the incremental cost under the project case of 'lost' renewable electricity from the sites is outweighed by the incremental benefits of avoided GHG emissions from biogas to electricity generation in both volumes (tonnes) and in monetary terms (using the VER). This means there is a net benefit in terms of emissions *in the electricity sector* from not producing electricity from these waste resources. This occurs because the NEM is forecast to increasingly shift to generation options that produce zero emissions (solar PV and wind generation).

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16 AEMO 2024, 2024 Integrated System Plan (ISP), 2024 ISP generation and storage outlook, Core, 2024 ISP - Step Change – Core, CDP3, NEM emissions trajectory, available from: https://aemo.com.au/-/media/files/major-publications/isp/2024/supporting-materials/2024-isp-generation-and-storage-outlook.zip?la=en

17 AEMO, 2024 ESOO Electricity Annual Consumption, available from: https://aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/forecasting-and-planning-data/electricity-forecasting-data-portal

Applied filters: Scenario is Central, Region is NEM, Publication is ESOO 2024, ESOO 2024 is 2024-08-29, ParentCategory is Operational (Sent Out), Total Operation consumption (excluding Energy Efficiency, Rooftop PV and Small Non Scheduled Generation)

18 This is most pronounced for the non-landfill sites where there is no biogas infrastructure or biomethane or electricity production infrastructure. This means the start date for biomethane production or electricity generation is 'delayed' relative to the landfill sites, and the average emissions intensity of other generation assets has fallen.

Further, there is the benefit in terms of avoided GHG emissions in the gas sector under the project case. As highlighted above, this benefit occurs because approx. 7PJ pa of biomethane across the eight sites substitutes for natural gas given total gas demand, including from 'hard to abate' demand, is likely to exceed the 7PJ pa of biomethane across the eight sites over the modelling period.

Table 8 shows that over the 30-year modelling period the total change in GHG emissions across gas and electricity sectors under the project case is unambiguously positive (net benefit).

This analysis shows the project options ***are*** "genuinely facilitating a more efficient use of the feedstock for emissions reduction" and are ***not*** "simply transferring emissions reduction from one sector to another".[19]

The economic value of this change in GHG emissions under the project case is a significant driver of the updated CBA results shown in Table 9. This analysis shows that using biogas as a source of electricity (alternative counterfactual) is not an efficient way of generating electricity, in terms of GHG emissions and the cost of electricity generation.

Table 8: **Changes in GHG emissions across gas and electricity under project case (feedstock for biomethane)**

Site	Emissions source	Total emissions (tonnes CO2-e from 2024 to 2053	Present value of emissions valued at the VER discounted at 7% pa ($FY24, millions)
Lilli Pilli	GHG emissions in electricity sector (emissions from other generation assets in NEM)	[redacted]	[redacted]
Lilli Pilli	Avoided GHG emissions in electricity sector (emissions from biogas to electricity at site)	[redacted]	[redacted]
Lilli Pilli	Avoided GHG emissions in gas sector (biomethane substituting for natural gas)	[redacted]	[redacted]
Lilli Pilli	**Total avoided GHG emissions across gas and electricity sectors**	[redacted]	[redacted]
Kauri	GHG emissions in electricity sector (emissions from other generation assets in NEM)	[redacted]	[redacted]

19 AER, draft decision: JGN access arrangement 2050 to 2030: Attachment 5- Capital expenditure: Confidential Appendix D, November 2024.

Site	Emissions source	Total emissions (tonnes CO2-e from 2024 to 2053	Present value of emissions valued at the VER discounted at 7% pa ($FY24, millions)
Kauri	Avoided GHG emissions in electricity sector (emissions from biogas to electricity at site)	[redacted]	[redacted]
Kauri	Avoided GHG emissions in gas sector (biomethane substituting for natural gas)	[redacted]	[redacted]
Kauri	**Total avoided GHG emissions across gas and electricity sectors**	[redacted]	[redacted]
Blue Gum	GHG emissions in electricity sector (emissions from other generation assets in NEM)	[redacted]	[redacted]
Blue Gum	Avoided GHG emissions in electricity sector (emissions from biogas to electricity at site)	[redacted]	[redacted]
Blue Gum	Avoided GHG emissions in gas sector (biomethane substituting for natural gas)	[redacted]	[redacted]
Blue Gum	**Total avoided GHG emissions across gas and electricity sectors**	[redacted]	[redacted]
Red Gum	GHG emissions in electricity sector (emissions from other generation assets in NEM)	[redacted]	[redacted]
Red Gum	Avoided GHG emissions in electricity sector (emissions from biogas to electricity at site)	[redacted]	[redacted]
Red Gum	Avoided GHG emissions in gas sector (biomethane substituting for natural gas)	[redacted]	[redacted]

Site	Emissions source	Total emissions (tonnes CO2-e from 2024 to 2053	Present value of emissions valued at the VER discounted at 7% pa ($FY24, millions)
Red Gum	**Total avoided GHG emissions across gas and electricity sectors**	[redacted]	[redacted]
Huon Pine	GHG emissions in electricity sector (emissions from other generation assets in NEM)	[redacted]	[redacted]
Huon Pine	Avoided GHG emissions in electricity sector (emissions from biogas to electricity at site)	[redacted]	[redacted]
Huon Pine	Avoided GHG emissions in gas sector (biomethane substituting for natural gas)	[redacted]	[redacted]
Huon Pine	**Total avoided GHG emissions across gas and electricity sectors**	[redacted]	[redacted]
Iron Bark	GHG emissions in electricity sector (emissions from other generation assets in NEM)	[redacted]	[redacted]
Iron Bark	Avoided GHG emissions in electricity sector (emissions from biogas to electricity at site)	[redacted]	[redacted]
Iron Bark	Avoided GHG emissions in gas sector (biomethane substituting for natural gas)	[redacted]	[redacted]
Iron Bark	**Total avoided GHG emissions across gas and electricity sectors**	[redacted]	[redacted]
Coolabah	GHG emissions in electricity sector (emissions from other generation assets in NEM)	[redacted]	[redacted]

Site	Emissions source	Total emissions (tonnes CO2-e from 2024 to 2053	Present value of emissions valued at the VER discounted at 7% pa ($FY24, millions)
Coolabah	Avoided GHG emissions in electricity sector (emissions from biogas to electricity at site)	[redacted]	[redacted]
Coolabah	Avoided GHG emissions in gas sector (biomethane substituting for natural gas)	[redacted]	[redacted]
Coolabah	**Total avoided GHG emissions across gas and electricity sectors**	[redacted]	[redacted]
Wollemi	GHG emissions in electricity sector (emissions from other generation assets in NEM)	[redacted]	[redacted]
Wollemi	Avoided GHG emissions in electricity sector (emissions from biogas to electricity at site)	[redacted]	[redacted]
Wollemi	Avoided GHG emissions in gas sector (biomethane substituting for natural gas)	[redacted]	[redacted]
Wollemi	**Total avoided GHG emissions across gas and electricity sectors**	[redacted]	[redacted]

Source: Frontier Economics

1.2 Results

Table 9: **Summary of CBA modelling: Incremental value of project options under Original Base Case vs Alternative waste to electricity counterfactual (central case) ($m, $FY2024, NPV)**

	Business Case results – incremental value of project options compared to original Base Case (June 24)	Updated results – incremental value of project options compared to alternative waste to electricity counterfactual * (Dec 24)

Lilli Pilli	[redacted]		[redacted]	
Kauri	[redacted]		[redacted]	
Blue Gum	[redacted]		[redacted]	
Red Gum	[redacted]		[redacted]	
Huon Pine	[redacted]		[redacted]	
Iron Bark	[redacted]		[redacted]	
Coolabah	[redacted]		[redacted]	
Wollemi	[redacted]		[redacted]	

Source: Frontier Economics

*Note: * Incremental costs and benefits of the Project Options, compared to the waste to electricity counterfactual for each of the eight sites. This includes the costs incurred by electricity service providers, producers, users and end users to generate electricity and connect to the market as well as the benefits received including the economic value of changes to greenhouse gas emissions in the electricity sector, relative to the project option involving biomethane production.*

See appendices for more detailed results by site.

1.3 Findings

#	Finding
Key Finding 1	**Significant investment in electricity-related infrastructure is required to produce electricity from waste resources.** These costs accrue to electricity service providers, producers, users and end users. The alternative counterfactual assumes investment in: • [redacted] • [redacted] • [redacted] Apart from the investment in new biogas production capacity which is required to produce electricity or biomethane at the [redacted] sites (and no longer an incremental cost under project option), the other costs of investment and operation of infrastructure to produce electricity at these sites are avoided under the project case. This is a significant positive driver of the economic value of the project cases, compared to the alternative counterfactual.

#	Finding
Key Finding 2	**Using biogas as a source of electricity (alternative counterfactual) is *not* an efficient way of generating electricity in terms of GHG emissions (valued under the VER).** **GHG emissions are associated with the production of electricity from biogas over the modelling period** (6.43 kg CO-e/GJ equivalent to 0.08 tonnes CO2-e/MWh). These emissions, and their economic value under the VER, are incurred under the alternative counterfactual and avoided under the project case. These incremental benefits accrue to electricity service providers, producers, users and end users. **GHG emissions are associated with the production of electricity from other generators in the NEM.** These emissions, and their economic value under the VER, are incurred under the project case and avoided under the alternative counterfactual. These incremental costs accrue to electricity service providers, producers, users and end users. **Over the modelling period, in dollar terms, the GHG emissions from the production of electricity from biogas at these sites electricity exceeds the GHG emissions from the production of electricity from other generators in the NEM** [redacted] This is a small positive driver of the economic value of the project cases, compared to the alternative counterfactual. We have not accounted for embodied carbon in the capital investments associated with electricity generation, biomethane generation or JGN pipeline assets.
Key Finding 3	**Using biogas as a source of electricity (alternative counterfactual) prevents decarbonisation of 'hard to abate' demands in the gas sector.** GHG emissions are associated with the consumption of natural gas over the modelling period. A significant portion of these costs are avoided under the project case when approx. 7PJ pa of biomethane substitutes for natural gas.[20] [redacted] under the VER over the modelling period**.** These incremental benefits accrue to gas service providers, producers, users and end users. This is a significant positive driver of the economic value of the project cases, compared to the alternative counterfactual.

[20] Noting that gas demand over the modelling period is forecast to significantly exceed the production of 7PJ pa of biomethane from the eight sites.

#	Finding
Key Finding 4	All project options produce a positive NPV and BCR using the alternative counterfactual. For the central case, the NPVs and BCRs for: [redacted] [redacted] This is primarily driven by the minimal change in the economic value of emissions in the electricity sector when utilising the feedstock for biomethane, and for [redacted] sites the significant investment in electricity-related infrastructure (including biogas facilities) required to produce electricity from waste resources. This analysis shows the project options ***are*** “genuinely facilitating a more efficient use of the feedstock for emissions reduction” and are ***not*** “simply transferring emissions reduction from one sector to another””[21] Most are higher than original base case, showing that using biogas as a source of electricity (Base Case) is not an efficient way of generating electricity, in terms of GHG emissions and the cost of electricity generation.

21 AER, draft decision: JGN access arrangement 2050 to 2030: Attachment 5- Capital expenditure: Confidential Appendix D, November 2024.

2 Additional information on key assumptions and sensitivity analysis

This section provides additional information on key assumptions and their impacts by undertaking sensitivity analysis, utilising the original base case and alternative waste to electricity counterfactual, including the following assumptions:

- an alternative estimate of the value of avoided gas supply & transportation costs (incl. AEMO 2025 Draft IASR);
- an alternative estimate of the value of biogas (opportunity cost from producing biomethane or electricity);
- a shorter modelling period, incl. removal of the residual value of plant (biogas, biomethane and electricity) and pipeline assets, to reflect risk related to long-term availability of feedstock;
- an alternative lower estimate of the value of digestate and food grade CO2.

The approach is to leave *all other* modelling processes and assumptions unchanged from the business cases submitted to the AER.[22]

2.1 Valuing avoided gas production and transportation costs

One of the key benefits of the project options is the avoided costs of natural gas production and transmission that results from the 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 to meet forecast gas demand incl. 'hard to abate' demand. Forecast demand is expected to exceed the 7PJ pa of biomethane produced at the eight sites over the modelling period.

The AER draft decision states:

> *A large proportion of the benefit of the projects are attributed to more efficient gas supply by avoiding the transportation and other costs…We consider that natural gas producer costs should be used and not the wholesale price…*
>
> *"It is unclear who benefits from the avoided cost of production and transportation of natural gas, or whether it is a surplus transfer between current natural gas producers, pipeline owners and renewable gas producers. JGN should clearly articulate how these costs represent a net benefit and not simply a surplus transfer.*[23]

This section sets out the approach to valuing these avoided costs, and then sets out why these avoided costs represent a net benefit (rather than a transfer between parties) and

22 With the exceptions of:

using actual June 2024 CPI instead of the forecast at the time of the preparation of the original business cases which impacts the gas market price and interim VER; and

updating the asset life of the biogas and biomethane plant to 30 years.

These two changes only slightly reduced the NPV and BCR under in the central case, for example Lilli Pilli's original NPV and BCR reduced from $296.78 million and 1.87 to $291.27 million and 1.86 respectively.

23 AER, draft decision: JGN access arrangement 2050 to 2030: Confidential Appendix D – Attachment 5

therefore relevant to the CBA and the assessment of overall economic value of the projects.

2.1.1 How to estimate the value of avoided gas production and transportation costs

We used an estimate of delivered gas prices from AEMO's 2023 IASR[24] and 2024 ISP[25]. The price forecasts were the delivered price of gas to industrial customers in NSW. Both price forecasts were based on reports for AEMO by ACIL Allen.

This is consistent with standard CBA guidance including NSW Treasury who note:

> *In a competitive market, market prices reflect the value of resources in alternative uses. Most markets for goods and services in New South Wales are largely competitive and, as a result, **market prices tend to reflect the value of resources used in production**. **Generally, CBA should use market prices to value the resources [emphasis add]**[26]*

We have sought to utilise publicly available information on the value of resources incorporated into the CBA.

Our expectation is that the gas price forecast, particularly over the medium to longer term broadly reflect costs of supply. ACIL Allen describes the GasMark model, which is used to develop gas price forecasts, as follows:

> *"At its core, GasMark is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipelines or LNG shipping elements.*
>
> *The equilibrium solution of the model is found using linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously.*
>
> *The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources, and end-users who have higher willingness to pay are served before those who are less willing to pay.*
>
> *…*
>
> *Although the model results in prices that are economically efficient, the model does take into account the change in pricing dynamics that has resulted from the market becoming internationally linked due to the development of the LNG projects in Queensland. This linkage moved domestic price formation towards LNG netback pricing. This fundamental change in pricing is taken into account in the model."*[27]

ACIL Allen makes clear that the model makes use of gas field production costs that are aligned with the assumptions used by AEMO.

In respect of industrial gas prices, ACIL Allen specifically comment that:

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24 AEMO 2023, 2023 Inputs Assumptions and Scenarios Consultation, Sydney, Step Change – Industrial, available from: https://aemo.com.au/-/media/files/major-publications/isp/2023/2023-iasr-assumptions-workbook.xlsx?la=en

25 ACIL Allen 2024, Gas, liquid fuel, coal and renewable gas projections, Sydney, Step Change – Industrial, https://aemo.com.au/-/media/files/major-publications/isp/2025/acil-allen-2024-price-forecast-data-files.zip?la=en

26 *TPG23-08: NSW Government Guide to Cost-Benefit Analysis, February 2023*

27 ACIL Allen, Natural gas price forecasts for the Final 2023 IASR and for the 2024 GSOO, Final report to Australia Energy Market Operator, 14 July 2023, page 8

> *"prices are expected to remain relatively steady until global LNG prices begin to fall, and the price cap is removed in 2025. Prices bottom out as LNG prices fall, then gradually climb back in line with pressures from the demand/supply balance and increasing costs of production."* [28]

This implies that in the early years of the forecast period LNG netback prices (which represent the opportunity cost of supplying gas) are driving industrial gas prices and for the remainder of the modelling period costs of production are driving industrial gas prices. For these reasons, it seems to us that these industrial gas price forecasts reflect gas producer costs as sought by the AER.

Nevertheless, these prices can be benchmarked against AEMO's estimates of gas production and transmission costs. Doing so requires some assumptions about what the marginal source of new gas supply will be over the modelling period (which is determined in ACIL Allen's GasMarket model). Potential sources of new supply from the domestic market to NSW include:

- Bowen-Surat Basin, for which AEMO reports a cost of 2C reserves (which would need to be developed over the modelling period) of $8.20/GJ. Delivery through the SWQP and MSP, for which AEMO reports combined tariffs of $2.76/GJ, would result in a delivered cost of $10.96/GJ.
- Gunnedah Basin, for which AEMO reports a cost of 2P and 2C reserves of $8.33/GJ. Assuming delivery would incur costs equal to those on the MSP, this would result in a delivered cost of $9.65/GJ.
- Victorian offshore basins, for which AEMO reports an average cost of 2C reserves (which would need to be developed over the modelling period) of $8.51/GJ. Delivery through the EGP, for which AEMO reports a tariff of $1.49/GJ, would result in a delivered cost of $10.00/GJ.

In addition to these domestic sources of new gas supply, both AEMO and the ACCC suggest that imported LNG is likely to play a role in meeting emerging supply gaps. Imported LNG is likely to have a cost of around $20.00/GJ.

Note that these cost benchmarks do not include the cost of storing gas so that it can be made available at times of peak demand in winter.

Based on these cost estimates, and considering that over the forecast period both domestic supply and imported LNG are likely to be the marginal source of supply at times, our view is that forecasts of industrial gas prices developed by ACIL Allen and used in our business cases are aligned with estimates of production costs.

For this reason, we consider publicly available forecasts of industrial gas prices remain appropriate to estimate the resource cost (or cost saving) from reducing 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 to meet forecast gas demand incl. 'hard to abate' demand.

We also note that the updated industrial gas price forecasts from ACIL Allen, produced for the 2025 Draft IASR, are higher than the Final 2023 IASR assumptions (see Figure 4).

These updated assumptions represent the most up-to-date publicly available estimate of the value of industrial gas prices and the resource cost (or cost saving) from reducing demand for natural gas.

Table 10 sets out the sensitivity analysis using this updated gas price forecasts, and shows a small increase in the estimate of the NPV and BCR of each project option.

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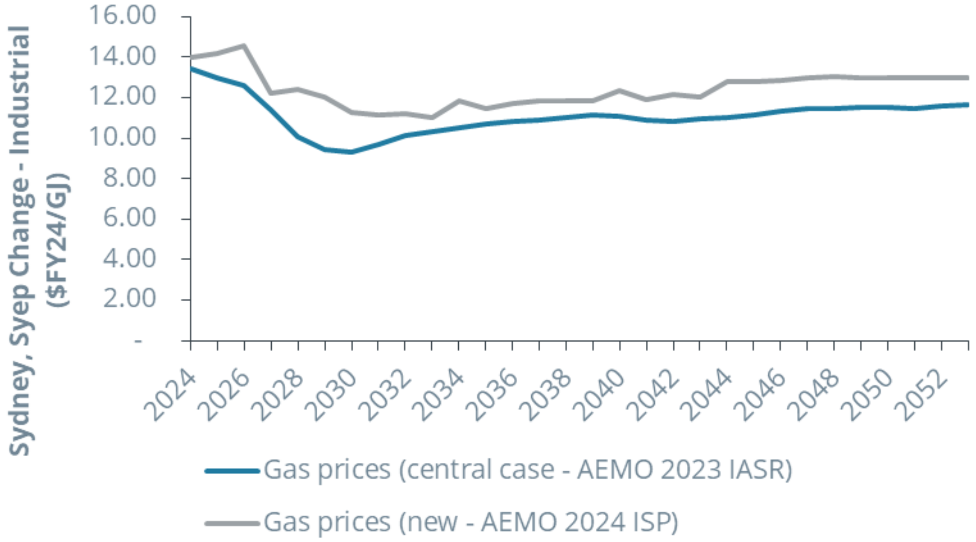
[28] ACIL Allen, Natural gas price forecasts for the Final 2023 IASR and for the 2024 GSOO, Fina report to Australia Energy Market Operator, 14 July 2023, page 24.

Figure 4: Forecasts of delivered industrial gas prices



Source: Frontier Economics analysis, based on AEMO 2023 IASR and AEMO 2024 ISP

2.1.2 Who benefits from avoided costs of supply

The AER has suggested that it is unclear who benefits from the avoided cost of production and transportation of natural gas. The AER has requested further information to identify whether it is a surplus transfer between current natural gas producers, pipeline owners and renewable gas producers, rather than an overall net benefit.

Numerous CBA guidelines published by jurisdictions incl. NSW Treasury state that a reduction in supply costs (avoided costs) represent an efficiency benefit and an improvement in societal welfare. For example, NSW Treasury CBA guidelines note:

> *There are multiple methods for measuring the same benefit… For example, an energy efficiency project could measure the benefit through valuing consumer savings based on retail energy prices, or it could measure the benefit based on avoided costs through the energy supply chain (lower generation costs, transmission and distribution infrastructure costs and retail costs).* [29]

This is suggesting a measure that reduces energy use (equivalent to reducing gas demand sourced from natural gas) creates a benefit to society and that this benefit can be measured by observing retail prices or estimating the resource cost saving across each element of the supply chain.

Applying this same logic to the gas market, reductions in the costs of gas supply (or avoided costs no longer incurred in producing and transporting natural gas because of biomethane production at the eight sites) represent a resource 'benefit' and does not represent a surplus. For this reason, these benefits are of relevance to CBA and the economic test envisaged under the NGR 79(2)(a).

Whether this reduction in costs accrues to producers or users is not relevant for CBA, and importantly, the NGR 79(2)(a) simply requires demonstration of the economic value accruing to JGN (as service provider), gas producers, users and end users.

However in most markets, these avoided costs benefit end-users in the form of lower prices. For example, the NSW Treasury CBA guidelines state that:

[29] 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

> *Savings in production costs may be passed on to **consumers** in lower prices (especially in a competitive market)*[30].

The expectation in energy markets, whether in contestable or non-contestable sectors of the energy market, is that users should ultimately benefit from avoided costs. This is set out in Box 1,

Box 1: Who benefits from avoided costs of supply?

The AEMC states that:

> *effective integration of these [energy] resources, **including avoided costs along the electricity supply chain, with associated reductions in consumer costs** [emphasis added]*[31]

The AEMO states that

> *The ISP represents the Optimised Development Path is the lowest-cost path through the NEM's transition to a net zero future…These transmission projects would **reduce costs for consumers** by delivering benefits that would recoup their $16 billion investment costs, **save consumers a further $18.5 billion in avoided costs** [emphasis added], and deliver emissions reductions valued at $3.3 billion*[32]

Source: Frontier Economics

2.1.3 Sensitivity analysis

Table 10: Summary of CBA modelling: Incremental value of project options under 2024 AEMO gas price forecast ($11.07/GJ) vs 2025 AEMO Draft IASR ($12.41/GJ) ($m, $FY2024, NPV)

	Business Case results (Original Base Case, ($11.07/GJ) * (June 24)	Updated results (Original Base Case, ($12.41/GJ) ** (Dec 24)	Updated results – (alternative counterfactual, ($12.41/GJ) ** (Dec 24)
Lilli Pilli	[redacted]		
Kauri			

[30] NSW Treasury (2023), *TPG23-08 NSW Government Guide to Cost-Benefit Analysis*, p. 62. https://www.treasury.nsw.gov.au/sites/default/files/2023-04/tpg23-08_nsw-government-guide-to-cost-benefit-analysis_202304.pdf

[31] AEMC, Integrating price-responsive resources into the NEM, August 2023.

[32] AEMO, 2024 Integrated System Plan - Overview

Blue Gum	[redacted]
Red Gum	[redacted]
Huon Pine	[redacted]
Iron Bark	[redacted]
Coolabah	[redacted]
Wollemi	[redacted]

Source: Frontier Economics

*Note: * To value the avoided costs of gas production and transportation the original Business Cases (central case) assumed an average of $11.07/GJ over the 30-year period, $FY2024) from AEMO's 2023 IASR and 2024 GSOO. Sydney, Step Change scenario – Industrial gas market price forecast.*

*Note: ** Assumes an average of $12.41/GJ over the 30-year period, $FY2024) from AEMO 2025 Draft IASR.*

We have also done additional analysis on a low gas price scenario which is assumed to be an average of $8.65 /GJ over the 30-year period ($FY2024) from AEMO's 2023 IASR and 2024 GSOO. Sydney, Green Energy Exports scenario – Industrial gas market price forecast. All project options at these sites still provide a positive overall economic value (NPV>0; BCR>1). There is also an updated forecast by ACIL Allen for the Green Energy Exports scenario, produced for the 2025 Draft IASR. The updated gas price forecasts for the Green Energy Exports scenario are higher than the equivalent forecasts from the Final 2023 IASR assumptions; using the updated forecasts would result in a higher NPV and BCR.

Table 11: Summary of CBA modelling: Incremental value of project options under 2024 AEMO gas price forecast ($11.07/GJ) vs low scenario ($8.65/GJ) ($m, $FY2024, NPV)

	Business Case results (Original Base Case, ($11.07/GJ) * (June 24)	Updated results (Original Base Case, ($8.65/GJ) ** (Dec 24)	Updated results – (alternative counterfactual, ($8.65/GJ) ** (Dec 24)
Lilli Pilli	[redacted]		

Kauri	[redacted]
Blue Gum	
Red Gum	
Huon Pine	
Iron Bark	
Coolabah	
Wollemi	

Source: Frontier Economics

*Note: * To value the avoided costs of gas production and transportation the original Business Cases (central case) assumed an average of $11.07/GJ over the 30-year period, $FY2024) from AEMO's 2023 IASR and 2024 GSOO. Sydney, Step Change scenario – Industrial gas market price forecast.*

*Note: ** Assumes an average of $8.65/GJ over the 30-year period, $FY2024) from AEMO's 2023 IASR and 2024 GSOO. Sydney, Green Energy Exports scenario – Industrial gas market price forecast.*

2.1.4 Findings

#	Finding
Key Finding 5	AEMO 2025 Draft ISAR forecast of industrial gas prices from ACIL Allen provides an updated estimate for the value of avoided gas production and transport costs. These estimates represent the best available and publicly verifiable forecast of the costs (or avoided costs) of gas production and transportation. These estimates are slightly higher than those assumed in the Business Case (central case) over the modelling period. All projects options, under both original Base Case and alternative counterfactual, produce a larger NPV and BCR using these updated estimates of forecast of industrial gas prices.

Key Finding 6	Reductions in the costs of supply (or avoided costs) represent a resource 'benefit' and not surplus or transfer between parties. For this reason, they are relevant to the CBA and the assessment of positive 'overall economic value' consistent with National Gas Rules (NGR) 79(2)(a), and calculated in accordance with Rule 79(3).
Key Finding 7	Using a lower value for avoided gas production and transport costs (based on AEOM's Green Energy Exports scenario rather than AEMO's Step Change scenario, reduces the benefits of the project options. However, project options still provide a positive overall economic value (NPV>0; BCR>1).

2.2 Valuing forgone value from use of biogas

[redacted]

2.2.1 Basis of assumptions

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[33] AER, draft decision: JGN access arrangement 2050 to 2030: Confidential Appendix D – Attachment 5

2.2.2 Sensitivity analysis

[redacted]

2.2.3 Findings

#	Finding
Key Finding 8	[redacted]

2.3 Shorter modelling period to reflect project risk

The analysis or modelling period defines the start and end date of a CBA.

Standard CBA practice is that this period should be long enough to capture all significant costs and benefits of the initiative. Generally, this means the analysis period should match the expected economic life or design life of the initiative.

2.3.1 Basis of assumption

The business cases assumed a modelling period of 30 years.

As shown in Figure 5, this period is at the low end of the range recommended by NSW Treasury's for capital projects.

Figure 5: NSW Treasury recommended CBA modelling periods

Type	Suggested analysis period
Capital	• **30-60 years** post-construction for most capital infrastructure types. • For assets with a long life, a residual value may need to be calculated (see Appendix 3.1).
Recurrent	• Match analysis period to the life of the initiative or the duration for which funding is requested. • Often **1-20 years** based on known ends dates including associated funding commitments.
ICT	• Often **2-5 years** and likely no longer than 10 years considering the short product lifecycle in ICT.
Regulation	• Long enough to capture all incremental impacts depending on the nature of the regulation. • Often **5-20 years**, depending on the nature of the regulation and how long it is likely to remain in force until reviewed.

Source: NSW Treasury (2023), TPG23-08 NSW Government Guide to Cost-Benefit Analysis, *p. 32.* *https://www.treasury.nsw.gov.au/sites/default/files/2023-04/tpg23-08_nsw-government-guide-to-cost-benefit-analysis_202304.pdf*

While the JGN pipeline may have a longer economic life or design life, as the analysis period gets longer, forecasting becomes more uncertain. For this reason, CBA guidelines including AER CBA guidelines for AEMO in preparing an ISP and TNSPs in applying the RIT, recommend utilising a residual value of assets when the modelling period is shorter than the life of the assets.[34] This was the approach taken in the business cases, and our preferred approach in other CBAs applied across various sectors on behalf of governments, regulators and utilities, rather than using a longer modelling period of say 60 years.

The AER draft decision states:

> *There are potential issues regarding the ongoing availability of feedstock for the production facilities. JGN's business cases assume a 30-year constant availability of*

[34] The AER requires the RIT-T proponent to use the ISP modelling period (also known as the planning horizon) of 20+ years as the default when assessing credible options to meet identified needs arising out of the ISP.

> *feedstock. JGN should model the impact of a shorter time horizon to determine project risk, and also provide information on why a 30-year time horizon is appropriate for each of the proposed projects.*[35]

Access to feedstock is critical to deliver the economic value of the projects. As is the conversation factor or production efficiency (output for a given level of feedstock).

The business cases undertook sensitivity analysis on both parameters:

- Renewable feedstock volumes[36]
- Renewable gas production efficiency[37]

However, the AER has requested further sensitivity by shortening the modelling period, thereby removing both incremental costs and benefits that would be incurred towards the end of the modelling period.

We have performed sensitivity analysis using a 24-year modelling period as set out in Table 13. This allows for up to 20 years of biomethane production. We have also assumed:

- construction timeframes, and operation periods for each site dependent on site and base case characteristics, [redacted]
- no residual value of plant and pipeline assets. If the rationale for this analysis is to reflect concerns over long-term access to feedstock (i.e. volumes are certain in short to medium term, but not long term), then it also makes sense to remove the residual value of plant and pipeline assets. In this unlikely scenario, we assume that without access to feedstock there is no value to these assets beyond 2047 i.e. end of economic life and 'no' scrap value.

Table 13: **Construction and operation dates for electricity generation under the alternative counterfactual and for biomethane injection under the project case (central case, 30 years)**

Site	Emissions source	Construction dates	Operation dates under central case, 30 years	Operation dates, under shorter modelling period, 24 years
Lilli Pilli	[redacted]			
Lilli Pilli	[redacted]			
Kauri	[redacted]			

[35] AER, draft decision: JGN access arrangement 2050 to 2030: Confidential Appendix D – Attachment 5

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

[37] 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.

Site	Emissions source	Construction dates	Operation dates under central case, 30 years	Operation dates, under shorter modelling period, 24 years
Kauri	[redacted]			
Blue Gum	[redacted]			
Blue Gum	[redacted]			
Red Gum	[redacted]			
Red Gum	[redacted]			
Huon Pine	[redacted]			
Huon Pine	[redacted]			
Iron Bark	[redacted]			
Iron Bark	[redacted]			
Coolabah	[redacted]			
Coolabah	[redacted]			
Wollemi	[redacted]			
Wollemi	[redacted]			

Source: Frontier Economics based on information from JGN

2.3.2 Sensitivity analysis

Table 14: Summary of CBA modelling: Incremental value of project options under original modelling period (30 years) vs shorter modelling period (24 years) ($m, $FY2024, NPV)

	Business Case results – incremental value of project options compared to original Base Case (30 years) (June 24)	Updated results - incremental value of project options compared to original Base Case (24 years) * (Dec 24)	Updated results – incremental value of project options compared to alternative waste to electricity counterfactual (24 years) ** (Dec 24)
Lilli Pilli	[redacted]	[redacted]	[redacted]
Kauri	[redacted]	[redacted]	[redacted]
Blue Gum	[redacted]	[redacted]	[redacted]
Red Gum	[redacted]	[redacted]	[redacted]
Huon Pine	[redacted]	[redacted]	[redacted]
Iron Bark	[redacted]	[redacted]	[redacted]
Coolabah	[redacted]	[redacted]	[redacted]
Wollemi	[redacted]	[redacted]	[redacted]

Source: Frontier Economics

*Note: * Note: This assumes a modelling period of 2024 to 2047 (24 years, incl. biomethane production of up to 20 years) and no residual value of plant and pipeline assets. This represents a scenario where there may be risks to long-term access to feedstock that cannot be managed, and the plant and pipeline assets provide no further value beyond 2047.*

*Note: ** Incremental costs and benefits of the Project Options, compared to the waste to electricity counterfactual for each of the eight sites over a modelling period of 2024 to 2047 (24 years).*

2.3.3 Findings

#	Finding
Key Finding 9	A shorter modelling period reduces the incremental costs and benefits of the project options, and the overall estimate of economic value. However, project options at all sites still provide a positive overall economic value (NPV>0; BCR>1) under both the original base case and alternative counterfactual in the unlikely scenario that there is no access to feedstock beyond 2047 and no value to these assets i.e. economic life is less than design life, and there is 'no' scrap value.

2.4 Lower value of digestate and food grade CO2 to reflect input uncertainty

Several of the business cases incorporated an economic value related to more efficient gas supply services through delivery of economies of scope in the production of renewable gas including through digestate and food/industrial grade CO2 production.[38] [redacted]

2.4.1 Basis of assumption

[redacted]

The AER draft decision states:

> *Some projects are supported by the benefit of sale of digestate and/or food grade CO2 by-products. Digestate is the remaining part of organic matter treated by anaerobic digestion, rich in nutrients and nitrogen, commonly used as an organic fertilizer in agriculture. These assumptions have a material effect on the viability of the projects and inform our assessment of completion and business continuity risk associated with projects. We consider JGN should provide further detail and evidence of the costs and potential benefits of the sale of these products.*[39]

We have performed sensitivity analysis using a 20% lower value for digestate, i.e. a value of digestate of [redacted] and using a 20% lower value for food/industrial grade CO2, [redacted]. This is consistent with single parameter testing when there is little evidence available to inform an alternative estimate.

38 [redacted]

39 AER, draft decision: JGN access arrangement 2050 to 2030: Confidential Appendix D – Attachment 5

While a lower value will reduce the estimate of economic value for the project options compared to the original base case, it does not change the estimate of economic value for the project options compared to the alternative counterfactual.[40]

A lower value of food/industrial grade CO2 will reduce the estimate of economic value for the project options compared to the original base case and compared to the alternative counterfactual as the food/industrial grade CO2 production is part of the upgrading process to convert biogas to biomethane.

2.4.2 Sensitivity analysis

Table 15: Summary of CBA modelling: Incremental value of project options under original value of digestate and food grade CO2 [redacted] vs. lower alternative value (20% lower) ($m, $FY2024, NPV)

	Business Case results (Original Base Case by-products valued at central case) * (June 24)	Updated results (Original Base Case, by-products valued at 20% lower than central case) ** (Dec 24)	Updated results – (alternative counterfactual, by-products valued at 20% lower than central case) ** (Dec 24)
[redacted]			

[redacted]

40 This is because digestate is a byproduct of producing biogas not biomethane and is not an incremental benefit when comparing project options to the alternative counterfactual. For this reason, utilising a lower value does not impact the results.

Table 16: Summary of CBA modelling: Incremental value of project options under original value of digestate at [redacted] vs. lower alternative value (20% lower) ($m, $FY2024, NPV)

	Business Case results (Original Base Case by-products valued at central case) * (June 24)	Updated results (Original Base Case, digestate valued at 20% lower than central case) ** (Dec 24)	Updated results – (alternative counterfactual, digestate valued at 20% lower than central case) **, *** (Dec 24)
[redacted]			

[redacted]

Table 17: Summary of CBA modelling: Incremental value of project options under original value of food grade CO2 at [redacted] sites vs. lower alternative value (20% lower) ($m, $FY2024, NPV)

	Business Case results (Original Base Case by-products valued at central case) * (June 24)	Updated results (Original Base Case, food grade CO2 valued at 20% lower than central case) ** (Dec 24)	Updated results – (alternative counterfactual, food grade CO2 valued at 20% lower than central case) ** (Dec 24)

[redacted]

[redacted]

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2.4.3 Findings

#	Finding
Key Finding 10	A 20% lower value of digestate reduces the benefits of the project options, and the overall estimate of economic value [redacted] sites when compared to the original base case. However, project options at these sites still provide a positive overall economic value (NPV>0; BCR>1). It does not impact the overall estimate of economic value for [redacted] sites when compared to the alternative counterfactual given digestate as a by-product is a 'benefit' for electricity and biomethane production (i.e. there is no incremental change between counterfactual and project option).
Key Finding 11	A 20% lower value of food/industrial grade CO2 reduces the benefits of the project options, and the overall estimate of economic value [redacted] sites when compared to the original base case and alternative counterfactual. However, project options at these sites still provide a positive overall economic value (NPV>0; BCR>1).

3 Conclusion

Based on this analysis presented in this technical note we conclude that waste to electricity is not a credible counterfactual for the project options given:

- The NGR 79(2)(a) and 79(3) are focused on the economic value accruing to JGN (as service provider), gas producers, users and end users, rather than electricity service provider, gas producers, users and end users (i.e. not designed to account for both gas and electricity market impacts);
- Even if accounting for both gas and electricity market impacts, the incremental value of the project options is larger when assuming waste to electricity is the counterfactual, relative to the original base case. This suggests there is more value to the community from alternative use or disposal of waste resources rather than electricity generation. This is likely reflected in the feedback from renewable gas proponents.

For this reason, the Base Case in the business cases remains the appropriate counterfactual.

When accounting for the 'new' sensitivities tested on the original Base Case, including shorter asset life and lower value of digestate and food grade CO2, each of the project options for each of the eight sites still produced a positive overall economic value is positive (NPV>0; BCR>1), calculated in accordance with Rule 79(3).

We conclude that the project options for each of the eight sites are justified under Rule 79(2)(a) of the National Gas Rules.

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