Report 2: Identifying the most investable biomethane project sites in Australia

Project RP1.2-06

January 2025

Project number: RP1.2-06

Milestone Report 2: Identifying the most investable biomethane project sites in Australia

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Cooperative Research Centres Program

This work is funded by the Future Fuels CRC, supported through the Australian Government's Cooperative Research Centres Program. We gratefully acknowledge the cash and in-kind support from all our research, government and industry participants.

Project Information	
Project number	RP1.2-06
Project title	Assessing the barriers to investability for biomethane grid injection projects
Research Program	RP1
Milestone Report Number	Milestone 2
Description	The scope, methodology and findings of an investigation into the most investable sites for biomethane projects in Australia
Research Provider	University of Adelaide (SET)
Project Leader and Team	Project Leader: Holger Maier Project Team: Holger Maier, Peter Ashman, Aaron Zecchin, Sam Culley, Olivia Smith
Industry Proponent and Advisor Team	Proponent: Patrick Lowry (AGIG) Advisor Teams: Jemena: Chen Tang Energy Networks Australia: Dennis R Van Puyvelde APA: Bart Calvert, Klaas van Alphen Energy Safe Victoria: Tyler Mason, Enzo Alfonsetti
Related Commonwealth Schedule	RP1.2.2 Techno-economic models and software for future fuel production technology completed. RP1.5.3 Feasibility studies for new demonstration project(s) in Australia delivered.
Project start/completion date	Sep 2023/Dec 2024
IP Access	**Open** – available publicly to all parties outside the CRC
Approved by	Patrick Lowry (AGIG)
Date of approval	January 2025

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Summary of Report

As the opportunities for biomethane as a renewable energy source continue to expand across Australia, there is an increasing focus on identifying the most investable locations for project development. A comprehensive understanding of the spatial factors influencing these investments is crucial, particularly in relation to the connection to existing infrastructure such as transmission and distribution lines. Accordingly, the purpose of this report is to provide a detailed analysis of the spatial considerations and infrastructure-related barriers that impact the investability of biomethane projects across Australia.

The report first contains a spatial analysis of the techno-economic viability of biomethane grid injection projects in Australia. This is built on prior work in Future Fuels CRC (FFCRC) projects RP1.2-04 and RP1.2-06 where a proto-type spatial analysis tool was developed. Additional research was undertaken to expand the analysis in two major areas: updating the costing estimates given the barriers to investability identified as part of RP1.2-06 Report 1 and adding carbon emissions and reduction estimates to the spatial assessment so that Australian Carbon Credit Units (ACCUs) can be explored as part of the wider business case. With these additions, the LCOE (Levelised Cost of Energy) for a biomethane project could be estimated at each point across Australia (see Figure i). Several assumptions about the type of project were made, including a 50km collection radius for feedstock, transport of feedstock to the plant at cost to the project, upgrading of biogas to biomethane via membrane separation and transport of biomethane to the gas grid via pipeline. Note that this assessment is focussed on agricultural waste and organic municipal waste, so landfill food processing waste and waste water projects are not included.

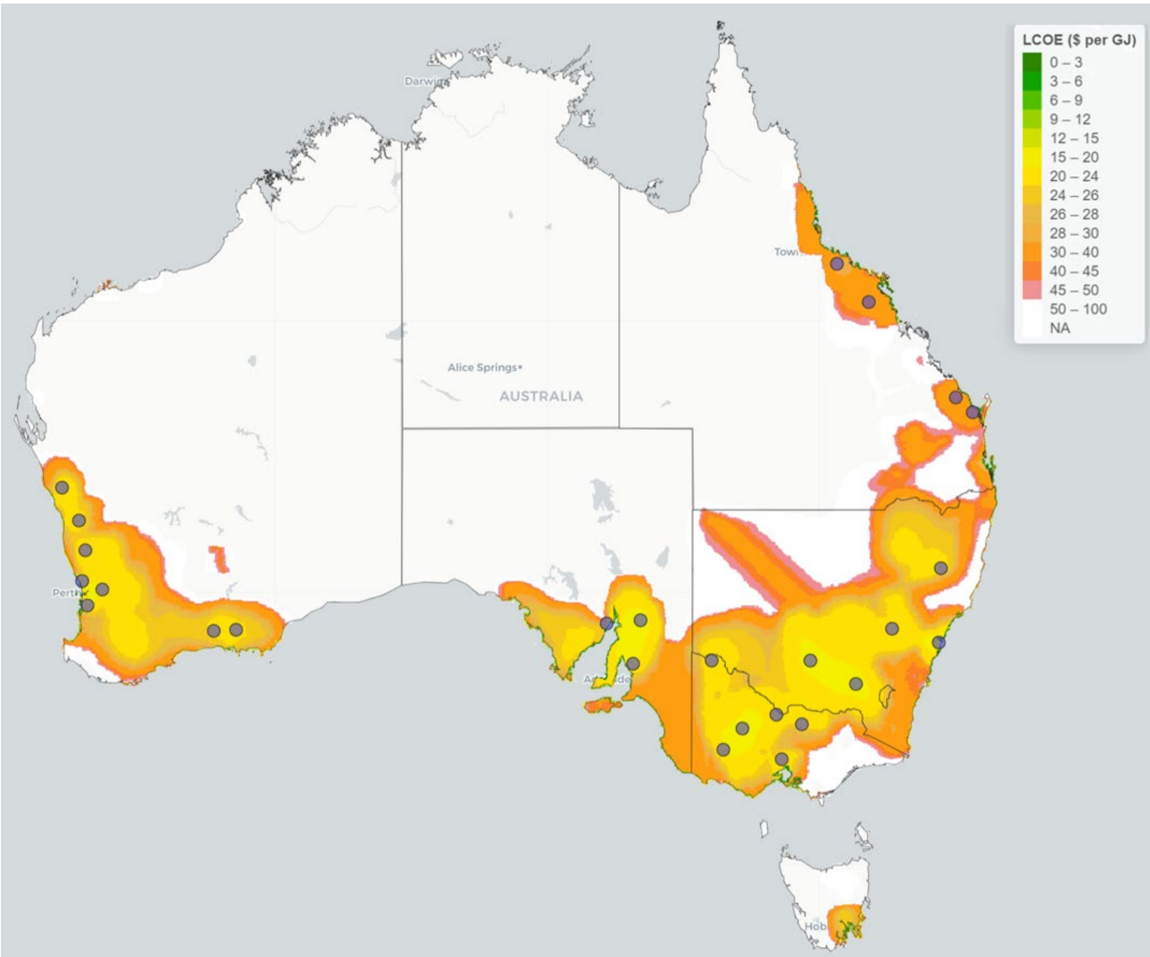

Figure i – Selected sites to form the first 20PJ of biomethane grid injection projects in each state, with a heatmap of LCOE for production at each 5 x 5 km site in Australia.

Following the estimate of the LCOE of a project, the most investable sites in each state could be identified. The first 20 PJs of biomethane in each state were identified by selecting the lowest LCOE site, and then the second lowest at least 100km away (due to an assumed 50km collection radius), and so on until 20 PJs were reached. The selected sites are shown in Figure i, with a breakdown of LCOE and available biomethane provided in this report. Results show that WA and NSW needed five to six sites compared to three in SA and QLD to reach the 20PJ total, which is a consequence of both the state total feedstock being a smaller amount and/or more spread out across the state, reducing the amount of bioenergy one project could capture. Note that these findings are heavily reliant on the ABBA dataset, which has high uncertainty in its estimates. In general, the results of the analysis indicate that common properties of the most investable sites include being located near transmission pipelines and having either year-round supply of one feedstock (such as municipal solid waste) or diversity of feedstock types (such as cereal straw and manure).

Based on the price of biomethane and the amount of biomethane available for each site, a summary cost curve was produced for each state (Figure ii). This was first produced for the baseline LCOE case, before also being explored under four policy scenarios to understand the impact this can have on investability (Table i).

Table i - Scenarios used in this report to explore the potential impact of different policy interventions on investability

Revenue Stream	BASELINE	Scenario 1: Revenue enabled	Scenario 2: Renewable gas Incentive	Scenario 3: Carbon displacement ACCU	Scenario 4: Bridging the gap
Tariff ($/GJ)	0	0	11	0	4
Displacement ACCU ($/t$CO_2$-e)	0	0	0	120	60
Gate fee ($/t)	0	60	0	0	40
Digestate ($/t)	0	100	0	0	100
Sale of CO_2 ($/t)	0	100	0	0	100

These cost curves show the impact of the four policy enabled scenarios on how commercially capturable 20PJ of biomethane can be. A reference line of $12/GJ is shown, the cap on the price of natural gas, to illustrate the point at which projects become investable. It can be seen that Scenario 4 is under the price of natural gas in each state, by design. Across the board, Scenario 3 (only a displacement ACCU) has the highest LCOEs other than the baseline, demonstrating that this revenue stream needs to work in tandem with other avenues of support for more projects to be investable. Scenarios 1 and 2, however, both bridge the gap for some sites, although the impact is different for each state. This is due to the interactions between plant size (of which those for cereal straw are largest) and plant utilisation (of which MSW and sugar cane have the highest year-round availability).

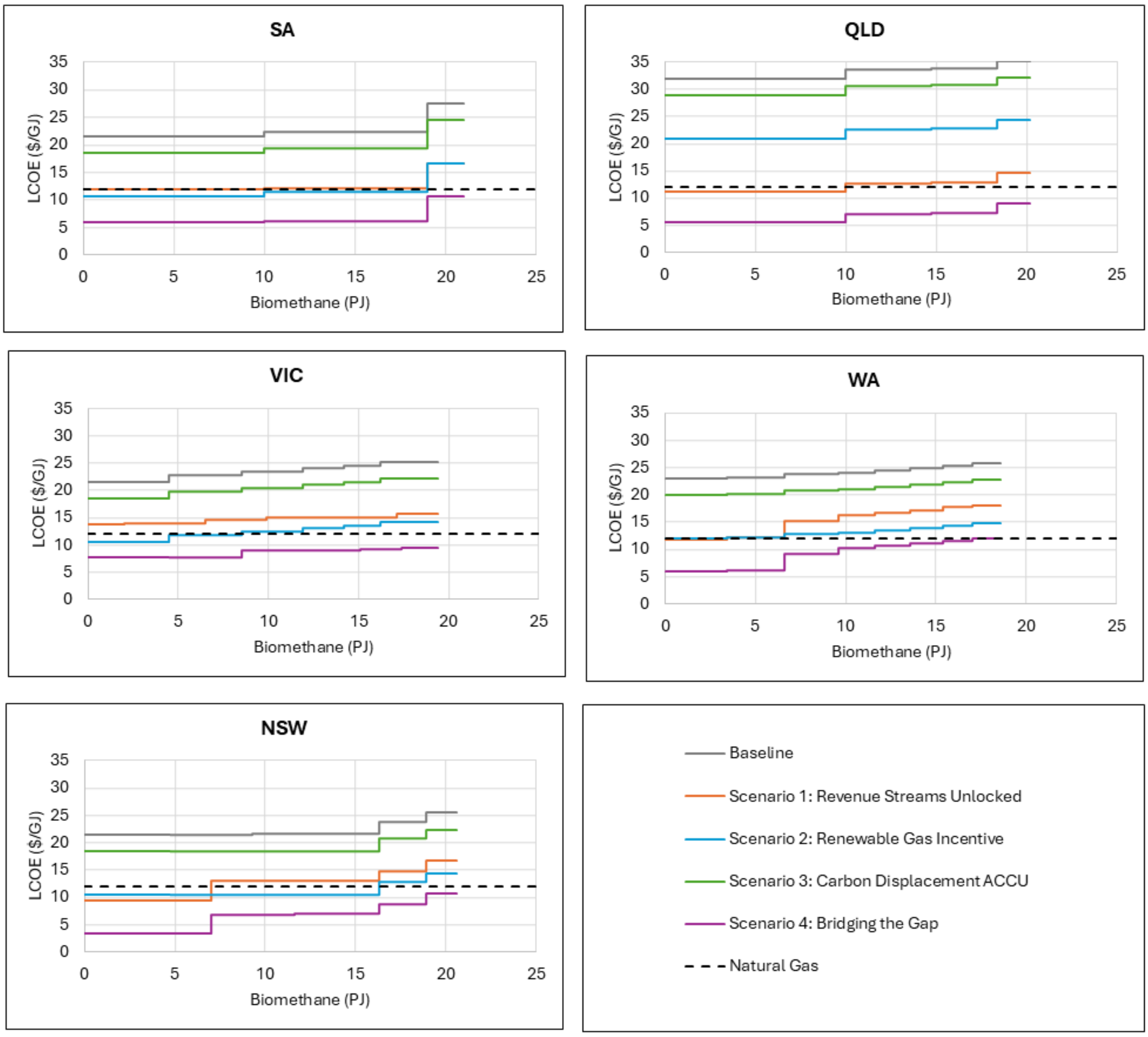

Figure ii - Cost curves of the first 20PJ of biomethane in each state. The coloured lines represent the four policy enabled scenarios.

The effect of injecting into distribution lines, instead of transmission lines, was also considered, which would mean a project does not have to transport biomethane as far in some cases, activating feedstock sources that were too far from transmission lines, while also reducing connection costs due to the lower pipeline pressures involved. The biggest challenge for these projects, however, is the smaller capacity of injection compared to transmission line projects, as the demand is much lower in many cases. This is particularly relevant when estimating the first 20PJ of biomethane in each state, as the total biomethane offered by a distribution line project would be smaller. Accounting for this, to investigate the potential for new sites along the distribution line, we first limited the feedstock amounts to 10,000T/year, and then re-ran the LCOE assuming that all projects were connecting to the distribution line. This modelling shows that, at a high level, the cost competitiveness of these projects is close to that of transmission line projects, with ranges of $25-30/GJ. Moreover, there are additional locations for investable plants that do not emerge when just focusing on transmission line projects, such as in the east of Victoria.

1. Introduction

1.1 Background

Despite the theoretical opportunity biomethane production and grid injection projects present for decarbonising the gas network, there are very few active projects in Australia. Organic feedstock suitable for biomethane production is instead being used for other purposes, including bioenergy products (e.g. Sustainable Aviation Fuel (SAF), cogeneration, etc). This is in stark contrast to our European and US counterparts where, for example, there are over 1,000 biomethane plants in Europe, and as part of the REPowerEU biomethane targets, countries are investing to provide ~1,200PJ of biomethane by 2030. The lack of active projects in Australia is primarily due to a lack of certainty around the investability of biomethane grid injection projects.

A series of knowledge gaps has been identified by industry members of the FFCRC (which is also reflected in the Bioenergy Roadmap for Australia), that need to be understood to ensure projects will be commercially successful and are thereby able to realise the opportunities to decarbonise energy systems using biomethane grid injection. These include both uncertainties on the supply side (the security of feedstock over a project life) and the demand side (the barriers to the success of a project given pipeline infrastructure and injection requirements at locations of interest), as well as what policy support might be required.

Project RP1.2-03 took the first steps towards providing the information needed by gas network owners to assess the viability of injecting biomethane into their networks in an Australian context by co-developing a high-level framework outlining the steps that need to be considered in such assessments, how they relate to each other and what appropriate data sources are required (Culley, Zecchin et al. 2021). RP1.2-04 then developed a user-friendly integrated assessment model that enables the high-level framework to be applied easily and reliably by end users to perform techno-economic viability assessments at locations of interest. Building on the work from RP1.2-04, this project (RP1.2-06) explores the investability of biomethane projects, builds additional detail and functionality into the tools developed in project RP1.2-04, and provides more confidence in the ability to identify critical sites, thereby promoting the development of the biomethane industry in Australia.

1.2 Purpose of this report

As the opportunities for biomethane as a renewable energy source are being made clearer across Australia, there is an increasing focus on identifying the most investable locations for project development. Given the acknowledgement that there are many barriers to investability currently, there is a need to identify the most commercially capturable sites in each state. As a result, this report focusses on understanding the spatial factors influencing how investable these projects are, particularly in relation to the connection to existing infrastructure such as transmission and distribution lines. The research in this report is organised into the following high-level areas:

1. **Improving the online mapping tool:** improving the equations and functionality of the online mapping tool developed in RP1.2-04 based on the findings from RP1.2-06 Report 1 (Culley, Smith et al. 2024). This tool will be made publicly available from March 2025.

2. **Spatial analysis of investable sites**: Identifying the most investable sites for biomethane projects, with a focus on where the first 20PJ of production can be developed in each state.

3. **The potential of distribution line connections**: Investigating the impact that connection to transmission lines versus distribution lines has on the investability and location of biomethane projects.

The remainder of this report is structured as follows: Section 2 describes the scope of the assessment, definition of investability and scope of the policy enabled scenarios explored. Section 3 details additions and changes made to the online spatial tool. Section 4 presents the spatial analysis of investable sites, and Section 5 presents the potential impact of distribution lines. Conclusions are presented in Section 6.

2. Framing of Investability Assessment

Now that biomethane projects are receiving more attention and momentum across Australia, there is a need to understand the great variability in the investability of projects, which can arise due to a combination of factors. In this section, we provide a framing for the assessment to understand key knowledge gaps and how they affect the investability of biomethane grid injection projects in Australia. We first describe the measurement of investability, and how it has been developed from the RP1.2-03/04 project approaches (Section 2.1). We then provide the scope of the assessment methodology, the framing of a baseline case, and specific policy enabled scenarios used to perform the assessment of investable sites (Section 2.2).

2.1 Measurement of investability

The measurement of investability builds on the approach from RP1.2-03/04, with additional focus on projects being commercially viable, and is defined as the expected profitability of investments in a biomethane project over the period of its project life. This focus places more of an emphasis on investigating potential costs and revenue streams over the project life, and less on market-based risks to projects such as competition for feedstock and contract security.

The consideration of investability is built on the combination of the two previous metrics from RP1.2-03/04: Levelised Cost of Energy (LCOE) and net Greenhouse Gas (GHG) reduction. It is important to note that throughout this report, the LCOE is estimated assuming a project life of 20 years and a discount rate of 7%. Over its project life, a biomethane project can be assessed by first considering the LCOE, and then the investability of the project can be assessed by considering potential revenue streams from (i) Australian Carbon Credit Units (ACCUs) calculated using methodologies as part of the Emissions Reduction Fund (ERF), (ii) other supplementary by-products such as biogenic CO_2 and digestate, and (iii) the sale of biomethane produced (Figure 1). In this report, four scenarios are used to explore the potential effects of policy and revenue (referred to as "policy enabled") and are described in Section 2.2.

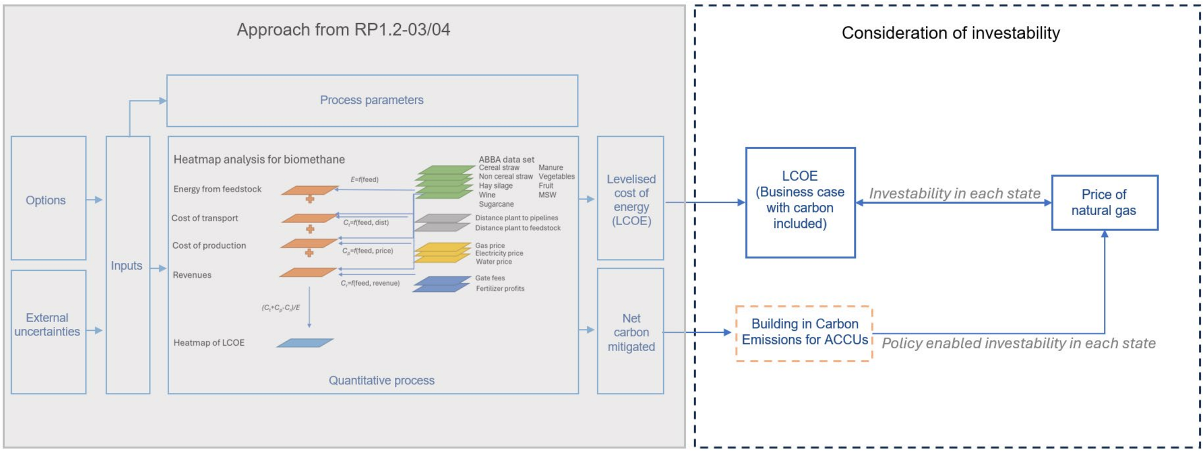

Figure 1 - Consideration of investability, building upon the framings from RP1.2-03 and RP1.2-04.

The scope of the assessment is based on the research areas of RP1.2-06, which were found to significantly affect the investability of projects, and adding them to our spatial assessment capabilities, which are modelled using the online mapping tool from RP1.2-04 (Figure 1). These new equations and data are described in Section 3 of this report. In particular, new additions to the methodology include:

- New revenue streams;
- Additional government policy support, in particular, distribution ACCU units from the ERF;
- New considerations of the cost of connection (transmission vs distribution lines);
- Improving other cost estimates for plant cost and upgrading costs, based on further research and feedback from industry for Report 1 (Culley, Smith et al. 2024).

A major caveat is that this analysis is driven primarily by agricultural feedstock sources, with municipal solid waste in more urban areas. We have not included data on wastewater treatment plants and landfill, food processing sites etc.

2.2 Scoping the assessment

The aim of this report is to identify the first 20PJs of biomethane for each state in Australia, by considering project investability (See Section 4). Results from RP1.2-06 Report 1 indicated that there is currently a gap for many projects between the cost of biomethane production (LCOE) and the price of natural gas (Culley, Smith et al. 2024). This gap can, however, be reduced by revenue streams and more direct support from government policy. Therefore, the investable sites will be identified under both a baseline case, and a set of policy enabled futures to also explore this impact. Section 2.3.1 first lists the major assumptions about project design that will be held constant throughout the analysis. Section 2.3.2 then lists the scenarios that will be used to investigate the first 20PJ in each state.

2.2.1 Assumptions in the Baseline Case

To estimate the investability of a biomethane plant at locations across Australia, certain assumptions need to be made about the plant design and then held constant despite the location. This does introduce a limitation compared to the project level assessment tool, which is capable of optimising a particular project. However, when considering all sites across Australia, this optimisation is not possible and instead a "broad" top-down approach must be used. In general, the plant is first sized based on the peak feedstock rate, a measure used to account for seasonality in some feedstock supplies. The feedstock (in a given collection radius) is then transported, generates biogas through anaerobic digestion, then a pipeline system is used to transport the biomethane to the gas grid. Assumptions about key operating decisions are shown in Table 1.

Table 1 – Baseline assumptions in the spatial assessment

Modelling assumptions	
Transport of Feedstock:	Via truck
Collection Radius:	50km
CO_2 removal:	Membrane
Methanation:	Not considered
AD temperature:	Thermophilic
AD moisture:	Dry
Flaring:	Off
Transport of Biomethane:	Via pipeline

2.2.2 – Scenarios of policy support

In order to investigate how the investability of the first 20PJs of biomethane in each state could be improved, four policy enabled scenarios are used (Table 2). Each scenario changes a combination of five levers: A feed-in-tariff, a displacement ACCU, a gate fee (charging for the disposal of waste at plant), digestate profit, and the profit from biogenic CO_2, captured as part of the biogas upgrading step. A baseline scenario is included, with no offsets to the LCOE.

Table 2 – Scenarios used in this report to explore the potential impact of different policy interventions on investability

Revenue Stream	Baseline	Scenario 1: Revenue enabled	Scenario 2: Renewable gas incentive	Scenario 3: Carbon displacement ACCU	Scenario 4: Bridging the gap
Tariff ($/GJ)	0	0	11	0	4
Displacement ACCU ($/t$CO_2$-e)	0	0	0	120	60
Gate fee ($/t)	0	60	0	0	40
Digestate ($/t)	0	100	0	0	100
Sale of CO_2 ($/t)	0	100	0	0	100

The first policy scenario, "Revenue enabled", is designed to illustrate that there are three potential revenue streams of the by-products of biomethane, that are not activated currently due to potential policy blocks. These include: adding incentives to dispose of waste in a carbon neutral way, creating additional use cases for digestate by removing restrictions for crop types based on upstream feedstock, and certifying biogenic CO_2 from biomethane projects as food grade. To reflect this, *Scenario 1* has used values for these revenue streams that reflect competitive markets (Culley, Smith et al. 2024). *Scenario 2* demonstrates the value from a direct feed-in-tariff for renewable gas. As implemented in this assessment, this is a relatively simple incentive mechanism as it is a flat level of support across different plant sizes and output (note that some tiered approaches are also used internationally). We have adopted values currently seen from governments in Europe, in order to see the potential impact in Australia. *Scenario 3* focuses on the benefits from displacement ACCUs, taking a forecasted value for ACCUs for 2030, suggested by the Australian energy markets commission (AEMC)[1]. *Scenario 4* is then designed to reverse engineer the gap between LCOE and the price of natural gas, with all five revenue streams activated, in order to illustrate what would be required for the commercial capture of the first 20PJs of biomethane. However, it should be noted that other combinations of the different revenue streams could also achieve this result. Consequently, the values used in Scenario 4 are not the only values that "Bridge the gap".

1 https://www.theguardian.com/australia-news/2024/apr/12/carbon-price-should-be-set-at-70-a-tonne-and-rise-six-fold-by-mid-century-says-aemc#:~:text=That%20price%20should%20increase%20steadily,gas%20and%20energy%20retail%20sectors, Accessed 10th Nov 2024

3. Additions to spatial assessment methodology

In order to identify the most investable sites in each state, the spatial assessment methodology needs to first be updated to reflect the work to date in RP1.2-06. This includes both the additions to the model identified in Report 1 (Culley, Smith et al. 2024), as well as updates to the main data and costing estimates. In summary, the spatial assessment methodology uses several key data sources (available biomass, distance to pipelines and costing parameters) to develop collections of spatial information, at a 5 x 5 km resolution, on energy from feedstock, cost of transport, cost of production and cost of connection. This is reflected in Figure 2, where the key data layers calculated are shown in orange. This is built on the work from RP1.2-04, which contained a simpler analysis focussed only on estimating LCOE, and no consideration of carbon emissions. Full details of that problem formulation are available in RP1.2-04 Report 2 (Culley, Zecchin et al. 2022). A summary of the changes to costing estimates, and improvements made since RP1.2-04, is provided in Section 3.1, followed by the addition of carbon emissions and mitigation described in Section 3.2.

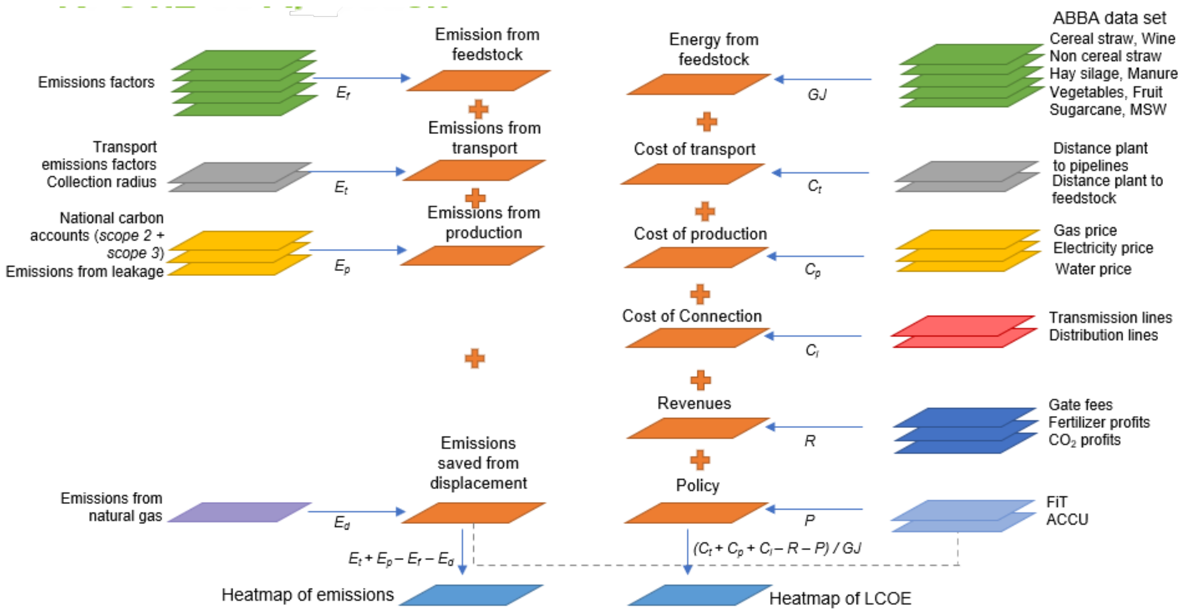

Figure 2 - Spatial assessment methodology to identify the most investable sites in each state. The right-hand side consists of the costing estimates and the left-hand side reflects the emissions.

3.1 Changes to cost estimates

Additions to the costing estimates have been made both to reflect new data gathered, as well as represent newly scoped processes in the online mapping tool. Examples of new data and equations include cost of connection, plant CAPEX and distance from pipeline, whereas the new functionality relates to additional policy and revenue options.

Cost of Connection was updated as a data layer to separate the distribution and transmission connections costs in order to provide a distinction between the different types of projects. While distribution lines will not be able to accept significantly large amounts of gas injected, there are much smaller connection costs required to do so. The connection costs were informed by RP1.2-06 Report 1 (Figure 16 - (Culley, Smith et al. 2024)). The pipeline data was updated in the Cost of Transport layer, reflecting the latest version of the spatial locations of pipelines provided by Geoscience Australia (updated 1st October 2024). The data was split to only include the gas pipeline data, and then turned into a spatial raster file to be used to calculate the distance from the plant to the pipeline shown in

Figure 3. The locations of distribution lines have also been added, taken as point locations from the gas pipeline register[2].

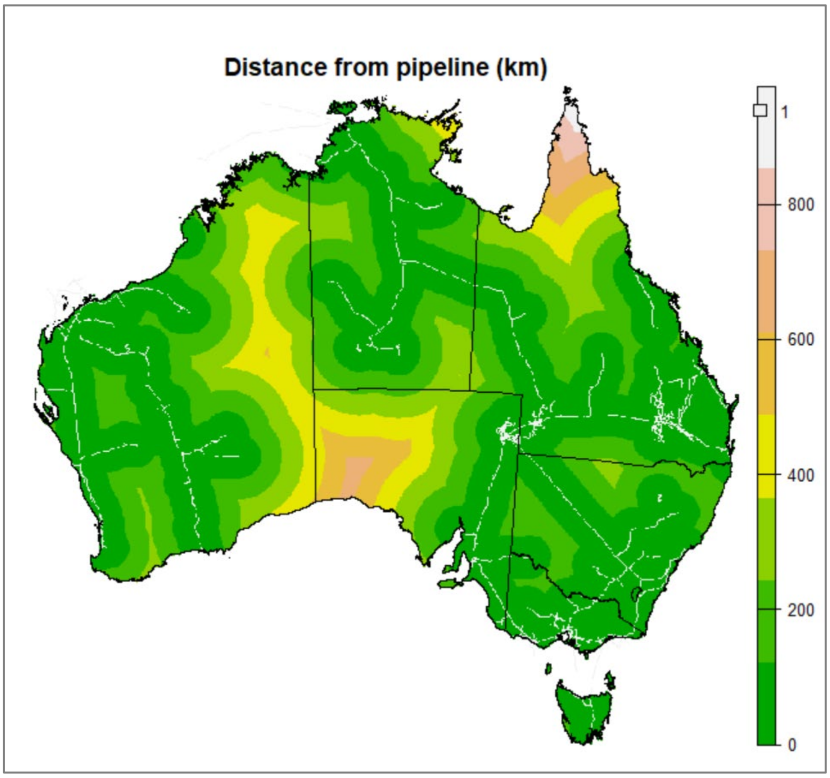

Figure 3 - Locations of gas pipelines and distance from pipeline

The changes to the costing estimates also influence the layers of CAPEX and OPEX, as observed in Figure 4. CAPEX of the plant was also updated to reflect economies of scale. A review of CAPEX costs in Europe (Sturmer, Kirchmeyr et al. 2016) found an estimate of the cost of constructing biomethane plants, which is based on the peak biomethane production capacity (m^3). In the tool, for each location, a collection radius is used to determine how much feedstock is available, and, based on the type of feedstock, what the peak feedstock rate would therefore be. The plant is then sized based on flow rate and costed accordingly (Figure 4, left). Note that areas where there is no CAPEX estimate, the ABBA dataset suggests there is no feedstock. In addition to the CAPEX changes, more minor changes to OPEX estimates were made based on data for cost of biogas upgrading (it was assumed that membrane separation was used). These equations are detailed in Report 1 from RP1.2-06 (Culley, Smith et al. 2024).

[2] https://www.aemc.gov.au/energy-system/gas/gas-pipeline-register#:~:text=The%20purpose%20of%20the%20pipeline,state%20and%20territory%20government%20authorities, accessed 13th Oct 2024

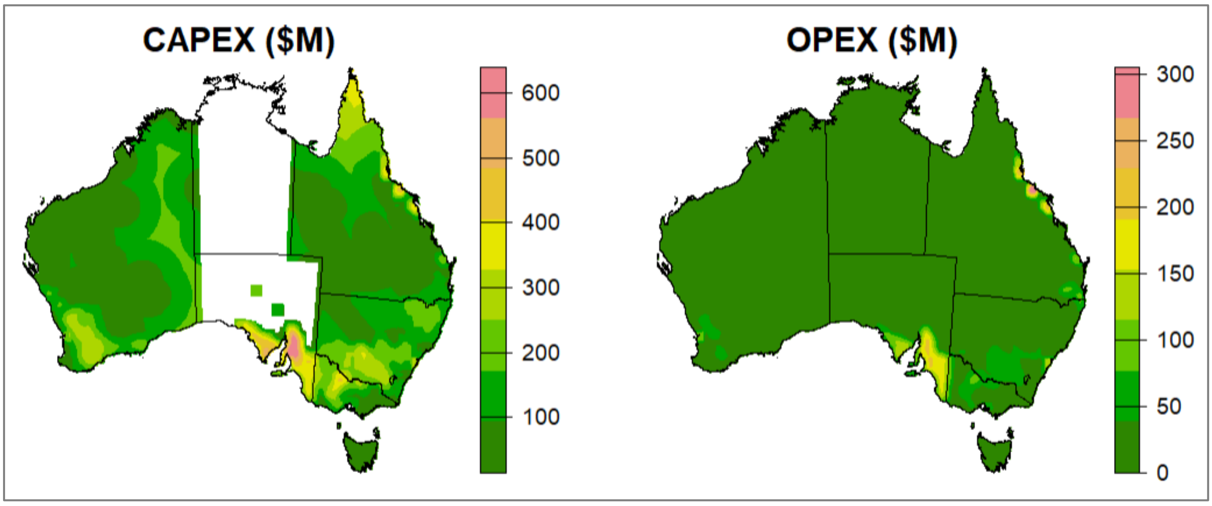

Figure 4 - CAPEX (left) and OPEX (right) of potential biomethane projects across Australia

Multiple options for policy and other revenue streams were added as spatial layers (Figure 2) to explore how to bridge the investability gap between biomethane and natural gas. The revenue streams explored include a gate fee, where the annual feedstock amount is multiplied by a $/tonne amount, and, the profit from solid digestate and biogenic CO_2, the amounts of which are estimated from the amount of annual feedstock and biogas, respectively. Note the CO_2 fraction of biogas is taken as 40%, and the solid, treated fraction of digestate is taken as 20%. The policy options consisted of Feed in Tariffs (FiT), a direct $/GJ income based on annual biomethane injected into the gas grid, and Australian Carbon Credit Units (ACCUs), where the displacement ACCU for biomethane projects is the only one used in the assessment. More details on this estimate are provided in Section 3.2.

3.2 Addition of carbon estimates

Carbon estimates have been incorporated into the spatial assessment in order to both present a wider business case for biomethane plants, and also estimate the revenue from ACCUs that is associated with biomethane projects. The carbon estimates have been split into four key layers: emissions avoided from capturing feedstock, emissions from transport, emissions from production and upgrading of biogas, and emissions avoided from the displacement of natural gas.

Emissions from feedstock are the emissions avoided from different feedstock types should they be captured in anaerobic digestion and burnt, and therefore converted to CO_2. Report 1 from RP1.2-06 investigated and discussed the limitations of quantifying these values for all feedstock types due to the dependence on both the crop type and existing use/management of the feedstock. The parameter values utilised within the layer were informed by Report 1 RP1.2-06 (Table 20 - (Culley, Smith et al. 2024)), where it can be seen that the feedstock sources with the highest GHG emissions are manure, and with the lowest being cereal straw. Note that while this capability has been built into the spatial assessment methodology, these emissions are not included in the calculation of ACCUs. This is because only the displacement ACCU is included, given there are no conversion abatement methodologies for all feedstocks used in the ABBA dataset at present (ARENA 2020).

Emissions from transport are comprised of the transport emissions factors and the collection radius. It is assumed that a truck would be used to transport the feedstock to the plant. The distance to transport the feedstock is taken as the radius that provides half the size of the collection area (35km for a 50km collection radius). The transport emissions factors align with the ECTA guidelines for measuring CO_2 emissions (McKinnon 2007), where the parameters assume a truck is making a return journey, with an empty payload upon return. The underlying assumption here is that the feedstock is evenly distributed, however, it should be noted that this factor has a limited impact on total emissions when compared to leakage of biogas and Scope 2 emissions (Culley, Smith et al. 2024).

The emissions from production of biogas consist of Scope 2 emissions from the grid, and emissions from leakage while treating and upgrading biogas. The national carbon accounts parameter guidelines are applied to the emissions from electricity usage within the biomethane process, including pretreatment, treatment, AD plant, compression, and digestate (Department of the Environment and Energy 2017). During upgrading biogas to biomethane and the separation of CH_4 from biomethane, leakage of emissions occurs, taken at 2%.

Emissions saved from displacement are the emissions avoided and displaced from a biomethane project injecting into the natural gas grid. For this assessment, a displacement ACCU is estimated, which is defined as the natural gas displaced from the grid, less the emissions required by the project specific to "biomethane activities"; i.e. upgrading the biogas to biomethane and injecting into the grid[3]. Taking an ACCU value of \$60/tCO_2e, a displacement revenue stream can be estimated for Australia (Figure 5, right). It can be seen that when compared to the operating costs, the displacement revenue stream is around 10% of the OPEX, providing a significant offset.

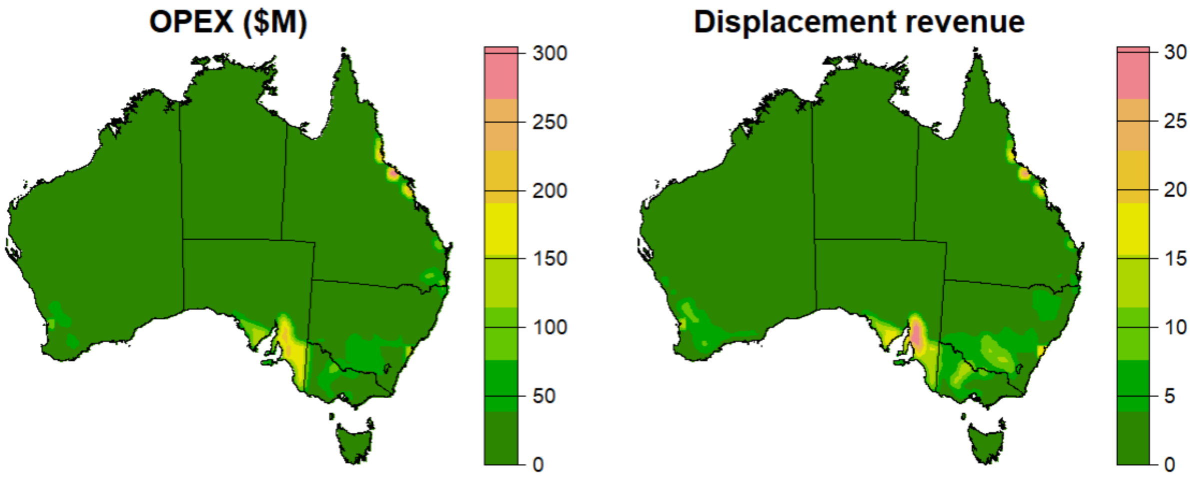

Figure 5 - OPEX (left) and Displacement Revenue (right) of a potential biomethane project

[3] cer.gov.au/document/biomethane-method-package-simple-method-guide, accessed 22nd Nov 2024.

4 Identifying most investable sites in each state

With the online assessment tool updated to reflect the additional scope for a techno-economic assessment in RP1.2-06, it can now be used to identify the most investable sites in each state. As mentioned in Section 2, the most investable sites can first be identified just using cost (i.e. LCOE) as a measure, before then exploring how the investability of these sites changes under different policy enabled scenarios.

4.1 LCOE maps

With the changes made as part of Section 3, a new baseline LCOE can be generated to explore the investability (Figure 6). The baseline estimates show the most investable sites with an LCOE of $20-25/GJ. Broadly, the lowest LCOE sites are those which have a large source of cereal and noncereal straw in close proximity to a pipeline. The main exception to this is in Queensland (QLD), which has a strong sugarcane feedstock source. In the baseline scenario, these QLD biomethane project locations are not quite as investable, which is primarily due to smaller plant sizes, and a lower biogas yield per tonne of feedstock. A consequence of applying the same assumed cost of transport across each feedstock type is that the operating costs are represented as larger in the model than they might otherwise be for a purely sugarcane focussed plant. This is the primary reason for developing an accompanying tool that can perform this assessment, as these assumptions can be changed for a more targeted investigation. A gate fee is one means to offset this transport cost using the tool, the effect of which is explored in further scenarios below.

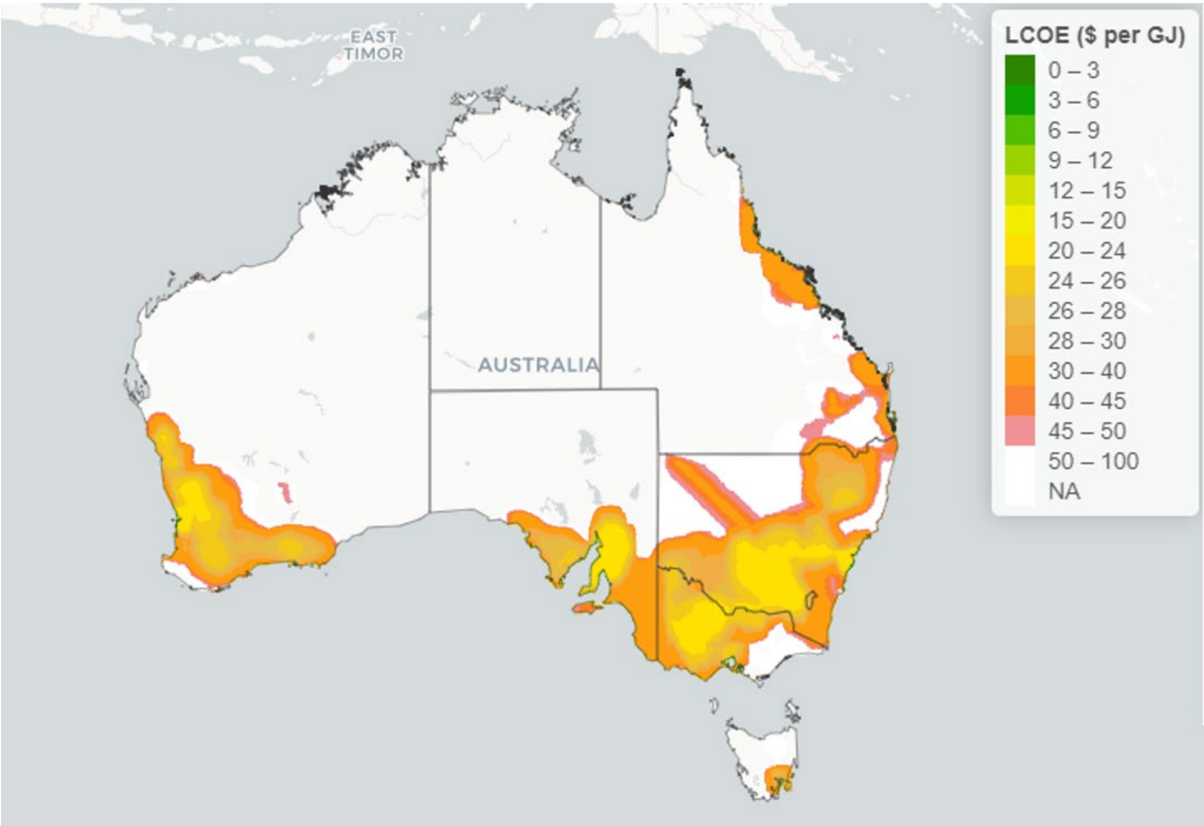

Figure 6 - Heatmap of the LCOE of a biomethane project, should it be located in each 5 x 5km cell in Australia.

Each of the four policy scenarios are shown in Figure 7, with an emphsis on under $12/GJ, $12-20/GJ to represent sites that are within reach of the price of natural gas, and then over $20/GJ. The four scenarios were: revenue enabled, renewable gas incentive, carbon displacement ACCU, and bridging the gap (Table 2). The results from

Scenario 1 ("Revenue enabled"), show that WA, QLD, NSW and SA each have locations below $12/GJ. As mentioned above, these revenue streams provide an offset to the operational costs, and hence plant utiliation through the year becomes the biggest factor in investability. As such, sites with a year round supply of feedstock are the most investable, which are the major cities using municipal solid waste and, to a slightly lesser extent, the sugar cane production in QLD.

Scenario 2 ("Renewable gas incentive") indicates the most investable sites are the large-scale, agricultural hub projects. This policy support scales directly with size of plant, and so the most viable sites align with the same locations as the baseline case, just at a lower LCOE. This demonstrates that more biomethane would become commercially capturable, should this $11/GJ level of support be provided (as evidenced by the sites in green in Figure 7). Scenario 3 ("Carbon displacement ACCU") identifies the same sites as the previous scenario, as the gas displacement ACCU also scales with plant size, however, this provides a lower level of support, and no sites are under the price of natural gas. Scenario 4 ("Bridging the gap"), by design, shows many locations across Australia that are investable. This did, however, require a combination of both direct policy support (feed in tariff of $4/GJ, ACCU of $60/t), and policy in place to unlock revenue streams (a gate fee, digestate profit and CO_2 profit). However, as mentioned previously, the same or similar levels of investability could have been achieved by different combinations of direct policy support and revenue streams.

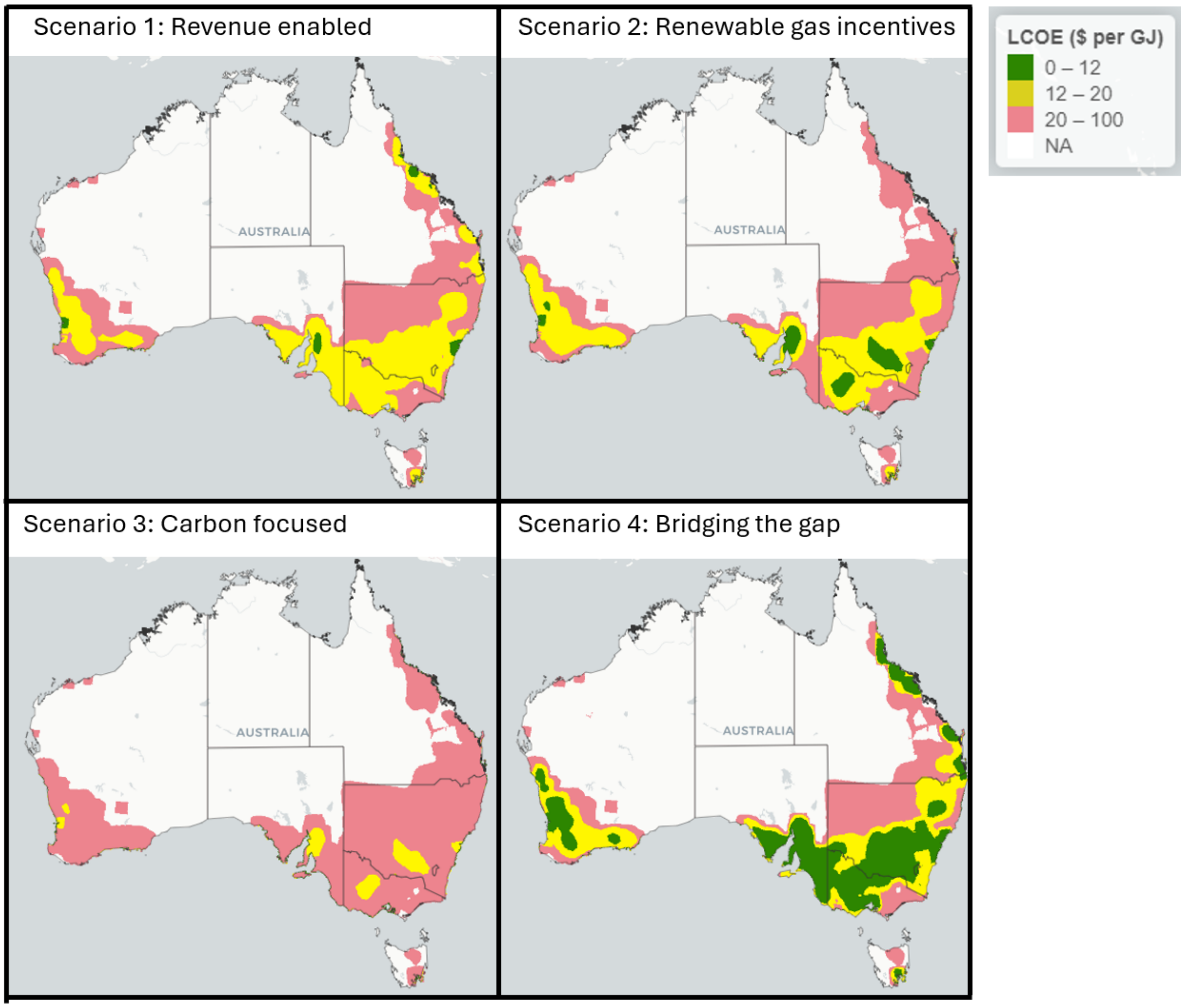

Figure 7 - Four policy enabled scenarios and their effect on the LCOE of biomethane projects

4.2 Most viable sites

With the LCOE maps generated in Section 4.1, the first 20PJs of biomethane in each state were identified. A selection algorithm was used that, for each state, first selected the lowest LCOE site, and then the second lowest at least 100km away, and so on until 20PJs were reached. The sites needed to be at least 100km away to avoid double counting any feedstock, as the collection radius of feedstock for a plant was taken at 50km (Section 2.2). The sites also needed to be within 50km of a pipeline to improve the practical feasibility of a project. The site selection was performed for the baseline case, with the LCOE for other scenarios provided in Table 3. A map of the sites selected is shown in Figure 8.

Some states needed five to six sites, compared to three sites for other states, to reach the 20PJ total, which is a consequence of both the state total feedstock being a smaller amount and/or more spread out across the state, reducing the amount of bioenergy one location could capture in its collection radius. Note that these findings are heavily reliant on the ABBA dataset, which has high uncertainty in its estimates. In general, the results of the analysis indicate that common properties of the most investable sites include being located near transmission pipelines and having either year-round supply of one feedstock (such as municipal solid waste) or diversity of feedstock types (such as cereal straw and manure).

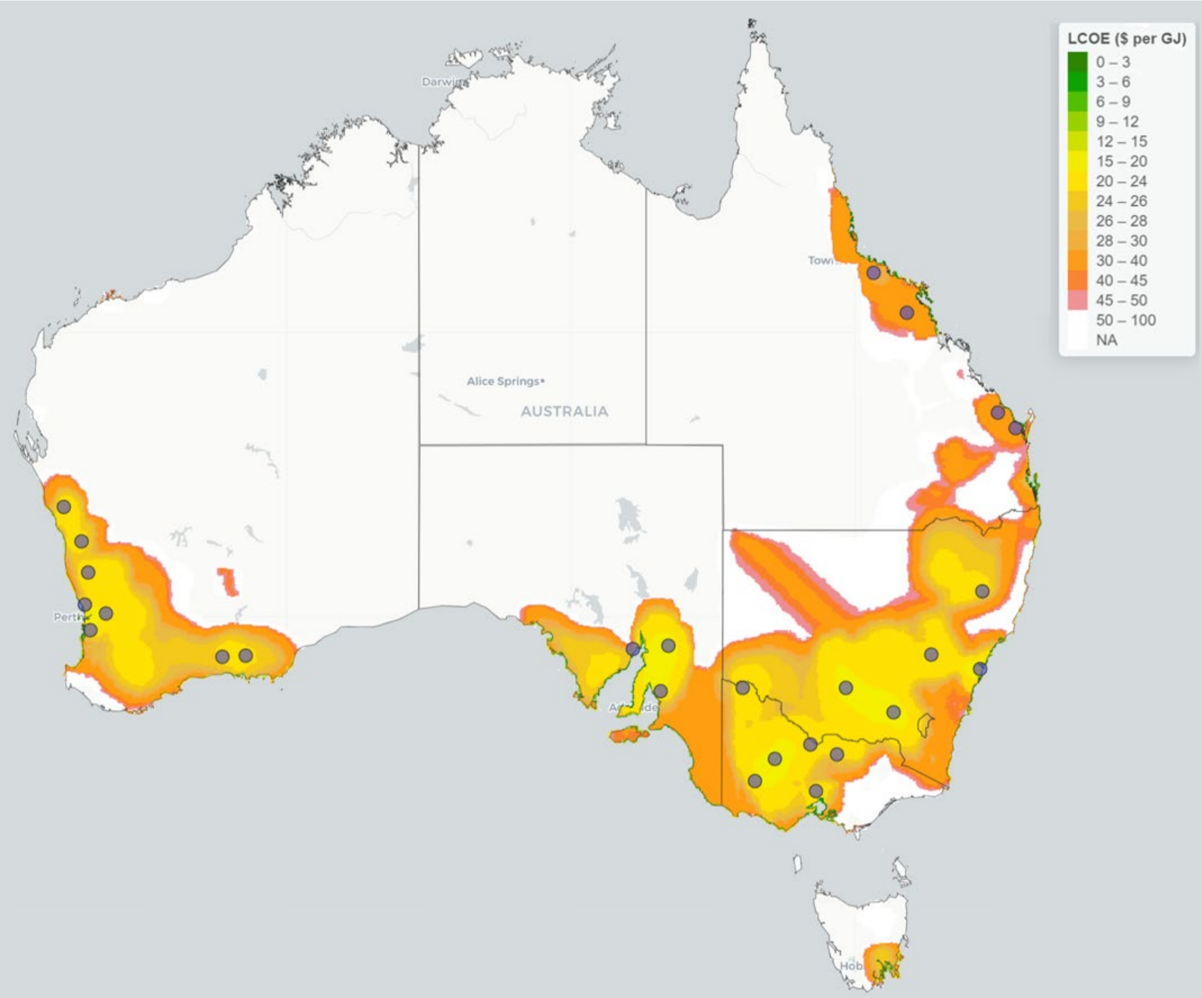

Figure 8 - The locations of the identified investable sites (first 20 PJ in each state) across Australia.

Table 3 – LCOE of the identified investable sites across the four policy enabled scenarios and baseline.

State	Site	LCOE ($/GJ)					
		Baseline	S1: Revenue streams unlocked	S2: Renewable gas incentive	S3: Carbon displacement ACCU	S4: Bridging the gap	Biomethane (PJ)
SA	Peterborough	21.5	11.9	10.5	18.5	5.8	10.0
	Mallala	22.4	12.2	11.4	19.3	6.1	9.0
	Whyalla	27.5	16.5	16.5	24.5	10.5	2.0
QLD	Woodstock	32.0	11.0	21.0	28.9	5.4	10.0
	Glenden	33.6	12.7	22.6	30.6	7.1	4.7
	Monduran	33.8	12.9	22.8	30.7	7.3	3.7
	Aldershot	35.2	14.5	24.2	32.2	8.9	1.8
VIC	St Arnaud	21.6	13.9	10.6	18.5	7.7	4.5
	Grampians	22.8	15.1	11.8	19.8	8.9	4.0
	Echuca West	23.5	14.7	12.5	20.4	8.6	3.4
	Mildura	24.0	15.6	13.0	21.0	9.5	2.3
	Northern Melbourne	24.6	13.7	13.6	21.5	7.7	2.0
	Shepparton East	25.2	15.1	14.2	22.1	9.0	3.2
NSW	Griffith	21.4	13.1	10.4	18.4	7.0	4.7
	Wagga Wagga	21.5	13.0	10.5	18.4	6.9	4.6
	Northern Sydney	21.6	9.3	10.6	18.5	3.4	7.0
	Orange	23.8	14.8	12.8	20.8	8.7	2.6
	Tamworth	25.4	16.7	14.4	22.4	10.7	1.7
WA	Yanchep	23.1	11.9	12.1	20.0	5.9	3.4
	Keysbrook	23.3	12.1	12.3	20.2	6.1	3.2
	Inkpen	23.9	15.2	12.9	20.8	9.1	3.0
	Rockwell	24.1	16.3	13.1	21.0	10.2	2.0
	Coomberdale	24.4	16.7	13.4	21.4	10.6	2.0
	Arrino	24.9	17.2	13.9	21.9	11.0	1.8
	*Wittenoom Hills	25.4	17.7	14.4	22.4	11.6	1.6
	*Cascade	25.8	18.1	14.8	22.8	12.0	1.6

*Note Kambalda to Esperance Gas Pipeline not currently in use

Using the LCOE and the PJ from each site, cost curves can be generated for each of the states (Figure 9). These cost curves show the impact of the four policy enabled scenarios on how commercially capturable 20PJ of biomethane can be. It can be seen that Scenario 4 is under the price of natural gas in each state, by design. Across the board, scenario 3 (only a displacement ACCU) has the highest LCOEs other than the baseline, demonstrating that this revenue stream needs to work in tandem with other avenues of support for more projects to be investable. Scenarios 1 and 2, however, both bridge the gap for some sites, although the impact is different for each state. This is due to the interactions between plant size (of which those for cereal straw are largest) and plant utilisation (of which MSW and sugar cane have the highest year-round availability).

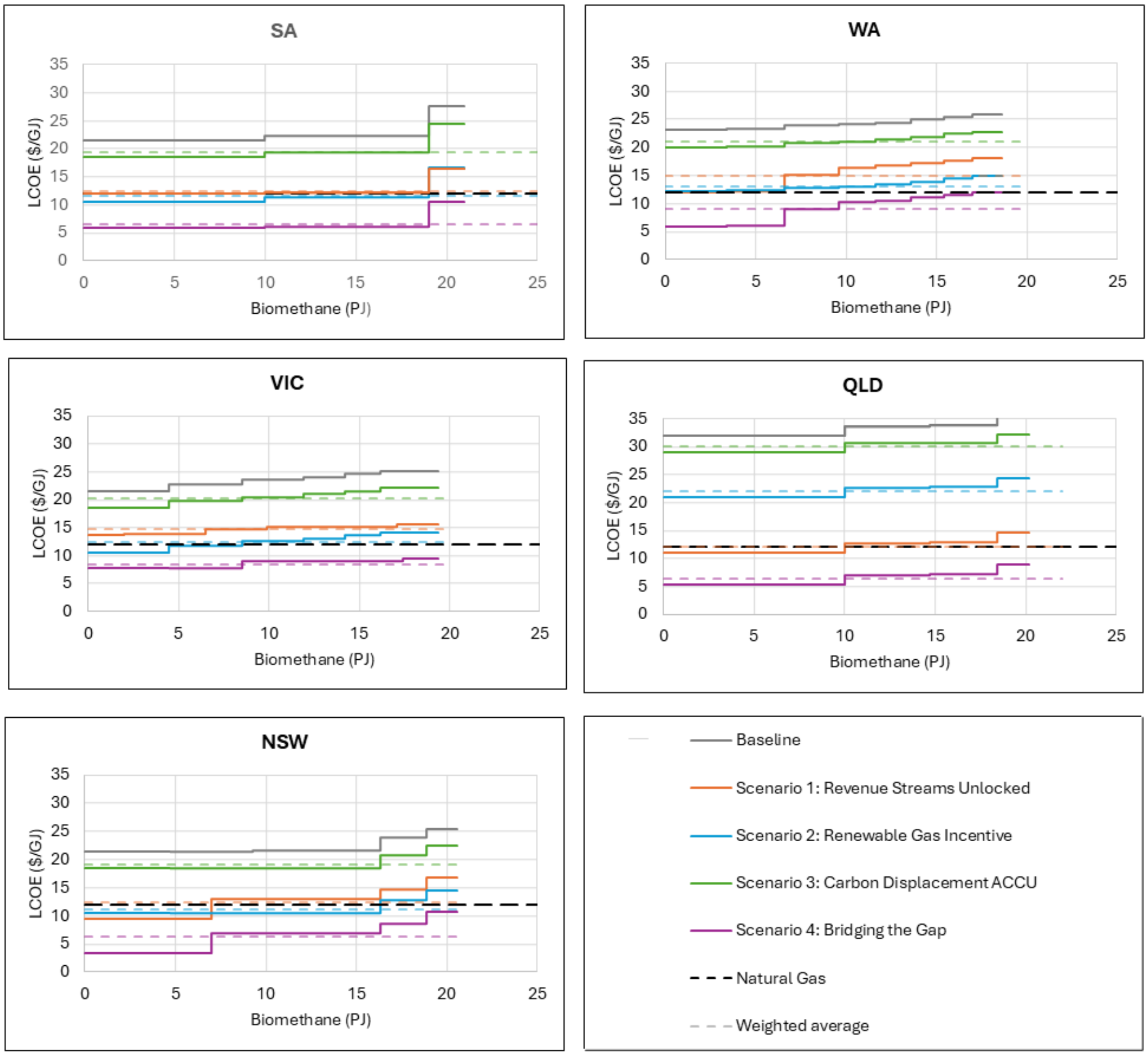

Figure 9 - Cost curves of the first 20PJ of biomethane in each state. The coloured lines represent the four policy enabled scenarios.

5. Effect of distribution lines on investable sites

A potential limitation of the previous analysis in Section 4 is that the biomethane projects identified were focused on projects injecting into a transmission line. There is an opportunity for projects to instead inject into distribution lines, which would mean a project does not have to transport biomethane as far in some cases, activating feedstock sources that were too far from transmission lines. There is also a lower cost of connection than compared to a transmission line, attributed to the lower operating pressures in the distribution lines. The biggest challenge for these projects, however, is the smaller capacity of injection compared to transmission line projects, as the demand is much lower in many cases. This is particularly relevant when estimating the first 20PJ of biomethane in each state, as the total biomethane offered by a distribution line project would be smaller.

Accounting for this, to investigate the potential for new sites along the distribution line, we first limited the feedstock amounts to 10,000tonne/year, using the definition of a “small scale” project from RP1.2-04 Report 2 (Culley, Zecchin et al. 2022). We then re-ran the LCOE assuming that all projects were connecting to the distribution line. This modelling shows that, at a high level, the cost competitiveness of these projects is close to that of transmission line projects, with ranges of $25-30/GJ (Figure 10). Moreover, there are additional locations for plants that do not emerge when just focusing on transmission line projects, such as in the east of Victoria (Figure 10). These sites are provided in Table 4, where it can be seen that additional sites were found in QLD, Vic and NSW.

Table 4 – Additional investable sites identified along distribution pipelines in Australia, when compared to the results of projects connected to transmission lines only.

STATE	Distribution Line Site
QLD	Toowoomba
Vic	Sale
	Wodonga
	Cobden
	Dimboola
NSW	Newcastle
	Dubbo

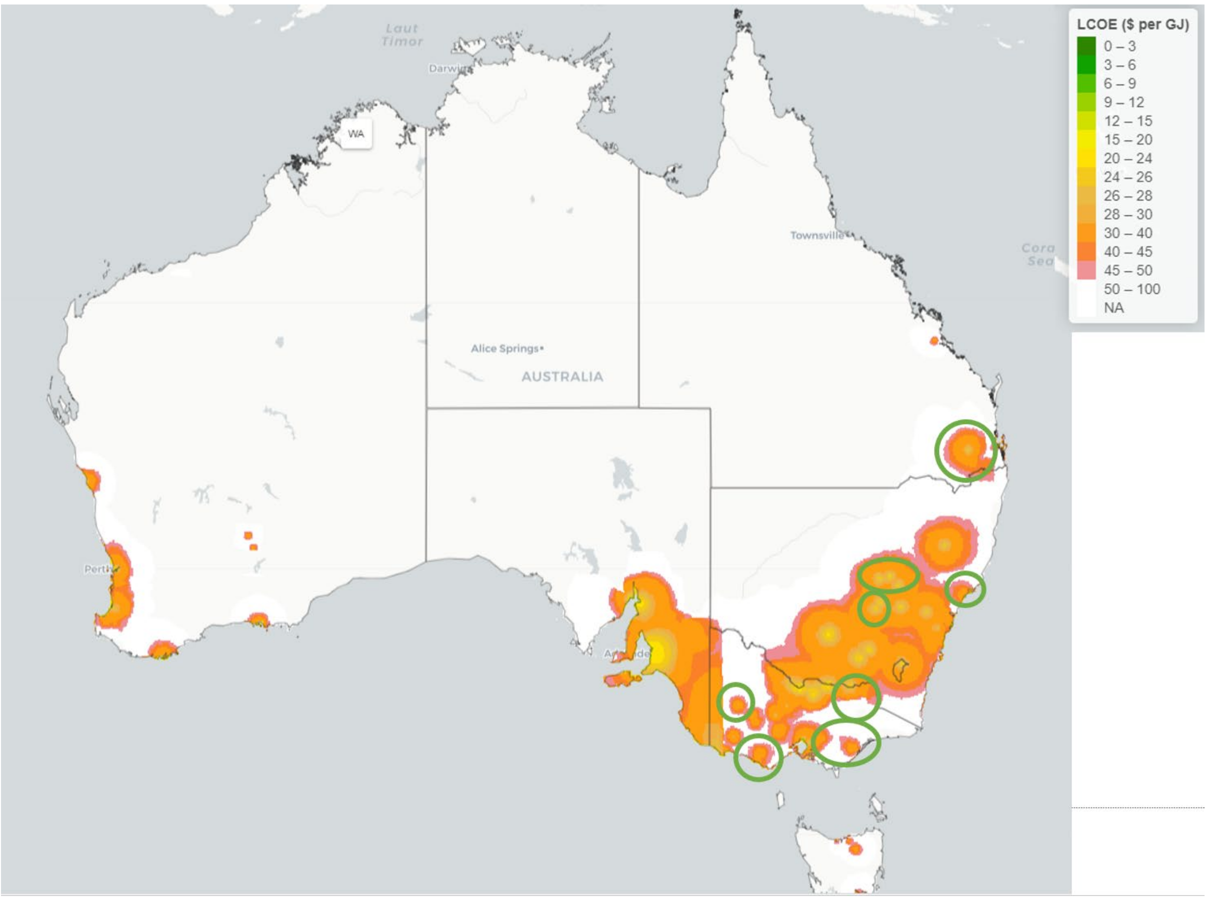

Figure 10 - Additional investable sites identified along distribution pipelines in Australia, when compared to the results of projects connected to transmission lines (represented by a green circle).

When broadening consideration beyond a particular project and instead considering the scale of the opportunity, such as identifying the first 20PJ of energy in each state, a large number of these smaller projects would be needed to make up that total given their smaller output. In this study, the limit of distribution line projects was taken at 10,000 tonne/year. There are, however, distribution lines that have much larger capacities that, while the cost of connecting to them would be slightly higher, have the potential to allow more biomethane projects to connect as the distance to a pipeline is reduced, making them play more of a role in the identification of the first 20PJ when compared with transmission lines. Therefore, in order to understand the full potential from distribution line projects, the holding capacity of distribution lines would be required.

The key trade-off that would decide whether a project is investable is: *do the savings from injecting in the distribution line with respect to cost of connection outweigh the slightly worse economy of scale from a smaller plant size?* An opportunity to improve the investability related to this trade-off is reverse compression. This is a process by which a project connects to a lower hosting capacity line (at cheaper cost, but with a lower demand), but then compressors are installed to pump the biomethane upstream into a transmission line, where there is higher demand. As a result, a biomethane project may save on cost of any connecting transmission pipeline.

6. Conclusions

This report first contains a spatial analysis of the techno-economic viability of biomethane grid injection projects in Australia. This builds on prior work from FFCRC projects RP1.2-04 and RP1.2-06, where a proto-type spatial analysis tool was developed. Additional research was undertaken to expand the analysis in two major areas: updating the costing estimates given the barriers to investability identified as part of RP1.2-06 Report 1, and adding carbon emissions and reduction estimates to the spatial assessment so that ACCUs can be explored as part of the wider business case. With these additions, the LCOE (Levelised cost of energy) for a biomethane project was estimated at each point across Australia (in a 5km x 5km cell), and the most investable sites in each state were identified.

To investigate how the investability of the first 20 PJs of biomethane in each state could be improved, four policy enabled scenarios were used. Each scenario changed a combination of five levers: a feed-in-tariff, a displacement ACCU, a gate fee (charging for the disposal of waste at plant), digestate profit, and the profit from biogenic CO_2, captured as part of the biogas upgrading step. A baseline LCOE scenario was included, with no offsets to the LCOE. Scenario 1 was designed to illustrate that there are three potential revenue streams of the by-products of biomethane, that are not activated currently due to potential policy blocks. These include: adding incentives to dispose of waste in a carbon neutral way, creating additional use cases for digestate by removing restrictions for crop types based on upstream feedstock, and certifying biogenic CO_2 from biomethane projects as food grade. Scenario 2 demonstrates the value from a direct feed-in-tariff for renewable gas, and adopted values currently seen from governments in Europe, to see the potential impacts in Australia. Scenario 3 focuses on the benefits from displacement ACCUs, taking a forecasted value for ACCUs for 2030, suggested by the AEM. Scenario 4 is then designed to reverse engineer the gap between LCOE and the price of natural gas, with all five revenue streams activated, to illustrate what would be required for the commercial capture of the first 20PJs of biomethane.

The baseline estimates show the most investable sites had an LCOE in the range of $20-25/GJ. Broadly, the lowest LCOE sites are ones which have a large source of cereal and noncereal straw in close proximity to a pipeline. The main exception to this is in Queensland (QLD), which has a strong sugarcane feedstock source. In the baseline scenario, these QLD biomethane project locations are not quite as investable, which is primarily due to smaller plant sizes, and a lower biogas yield per tonne of feedstock. A consequence of applying the same assumed cost of transport across each feedstock type is that the operating costs are represented as larger in the model than they might otherwise be for a purely sugarcane focussed plant. This is the primary reason for developing an accompanying tool that can perform this assessment, as these assumptions can be changed for a more targeted investigation.

Using the LCOE and the PJ from each site, cost curves were generated for each of the states. These cost curves show the impact of the four policy enabled scenarios on how commercially capturable 20PJ of biomethane can be. It can be seen that Scenario 4 is under the price of natural gas in each state, by design. Across the board, Scenario 3 (only a displacement ACCU) has the highest LCOEs other than the baseline, demonstrating that this revenue stream needs to work in tandem with other avenues of support for more projects to be investable. Scenarios 1 and 2, however, both bridge the gap for some sites, although the impact is different for each state. This is due to the interactions between plant size (of which those for cereal straw are largest) and plant utilisation (of which MSW and sugar cane have the highest year-round availability).

The effect of distribution lines was also considered. There is an opportunity for projects to instead inject into distribution lines, which would mean a project does not have to transport biomethane as far in some cases, activating feedstock sources that were too far from transmission lines. There is also a lower cost of connection than compared to a transmission line. The biggest challenge for these projects, however, is the smaller capacity of injection compared to transmission line projects, as the demand is much lower in many cases. This is particularly relevant when estimating the first 20PJ of biomethane in each state, as the total biomethane offered by a distribution line project would be smaller. Accounting for this, to investigate the potential for new sites along the distribution line, we first limited the feedstock amounts to 10,000tonne/year. We then re-ran the LCOE assuming that all projects were connecting to the distribution line. This modelling shows that, at a high level, the cost competitiveness of these projects is close to that of transmission line projects, with ranges of $25-30/GJ. Moreover, there are additional locations for plants that do not emerge when just focusing on transmission line projects, such as in the east of Victoria.

7. Recommendations to industry

A key summary of findings for project operation is as follows:

- Clarity around the holding capacity of distribution line projects will enable a secondary estimate of how much biomethane is available in these networks.
    - The key trade-off that would decide whether a project is investable is: do the savings from injecting in the distribution line with respect to cost of connection outweigh the slightly worse economy of scale from a smaller plant size?
- When considering potential project sites, forming a common understanding of what additional feedstock streams are available will be important, especially food processing streams given producers of this waste are often also users of gas.

A key summary of findings for policy investigations is as follows:

- Direct policy support such, as a feed in tariff in line with Europe (~$11/GJ), makes approximately the first 10PJ in each state commercially viable. In this report, this was modelled as a flat tariff rate, but this type of support can be individually negotiated by a project akin to the Contract for Difference (CfD) schemes the state governments have recently implemented for power and storage projects.
- As an alternative, a combination of revenue streams from the by-products of biomethane (gate fee, digestate profit and CO_2 profit) also assist in many sites across Australia approaching the price of natural gas. There are policy interventions that would unlock these revenue streams, such as incentivisation of waste management, and encouragement of circular uses of byproducts by removing barriers for digestate and CO_2 use.

8. Next Steps and Future Work

This report is the second major milestone report for RP1.2-06. The final steps of this work are to update the accompanying tools and make them available to the public. Particular, the online mapping tool that accompanies this report will be made available in March 2025. A summary report will also be produced, outlining the functionality of the final version of the tools, which will be attached to RP1.2-04.

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