Report 4: Project Summary Report

FFCRC RP1.2-04 and RP1.2-06

March 2025

Project number: RP1.2-04 and RP1.2-06

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PROJECT INFORMATION	
Project number	RP1.2-04 and RP1.2-06
Project title	Integrated model for bio-methane injection in gas networks
Research Program	RP1
Milestone Report Number	Summary Report 4
Description	The scope, methodology and findings of a sensitivity analysis to determine which factors have the largest effect on biomethane project viability
Research Provider	University of Adelaide (SET)
Project Leader and Team	Project Leader: Holger Maier Project Team: Holger Maier, Peter Ashman, Aaron Zecchin, Tara Hosseini, 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 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	May 2021/Oct 2024
IP Access	**Restricted** – available to participants only
Approved by	
Date of approval	

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Glossary of Terms

ACCU	Australian Carbon Credit Units
AD	Anerobic digestion plant
Carbon saved	The net carbon saved from operation of the AD biomethane project, in terms of tCO_2e/year.
CAPEX	Capital expenses of a project ($)
CO_2 gas sale	The profit from processing and selling food grade CO_2 ($/tonne).
Conversion ACCU	The ACCU from a tonne of carbon emissions avoided by a biomethane project capturing organic feedstock ($/tonne CO_2-e).
Digestate profit	The profit that is received from selling 1 tonne of processed solid digestate ($/tonne).
Direct grant funding	The offset to CAPEX of the AD plant (i.e. excluding cost of connection to grid) as supplied from a government grant ($).
Displacement ACCU	The ACCU from a tonne of carbon emissions displaced by a biomethane project injecting into the grid ($/tonne CO_2-e).
Energy density	The energy content of gas produced per tonne of feedstock input, i.e. gravimetric energy density in GJ/tonne.
Feed in Tariff	The average Feed in Tariff amount over a 20-year project lifetime ($/GJ).
Fugitive emissions from gas networks	Fugitive emissions in the transport and consumption of gas outside of the biomethane projects themselves (i.e. gas networks and consumption in consumer appliances).
Gate fee	The income from charging to dispose of waste at the plant ($/tonne).
Green Gas Support Scheme	A tiered support scheme from the UK that provides a tariff based on biomethane production ($/GJ), represented here as the average level over the project life.
LCOE	The LCOE is estimated by calculating the total discounted lifetime costs (or, the net present value), divided by the total discounted energy output.
LCOE*	In some scenarios where a revenue stream is present (from selling byproducts or a government policy etc.), we adjust the standard measurement of LCOE to include the net project costs, not total project costs. The primary reason for this is to acknowledge that revenue streams reduce the gap between the LCOE and the market price of natural gas so that projects can be profitable, allowing for a consistent comparison across the analysis. But it is important to note in these cases that the inherent cost of the biomethane is not changed. This adjusted measure of LCOE will be denoted in the report using LCOE*.
OPEX	Operational expenses of project ($/year)
RGGOs	A renewable gas guarantee of origin scheme ($/MWh).

Summary of Report

Despite the clear need to decarbonise energy use in Australia, the pathway for heavy industry and other sectors remains unclear. One opportunity to decarbonise industries currently reliant on natural gas is via biomethane projects, already a proven technology in Europe and the US. This technology captures carbon emissions from organic waste (referred to as feedstock) to be an overall carbon abatement, and produces a fuel fit for use with existing infrastructure, such as gas pipelines for transport and demand-side technology for end of use. Despite the opportunity that biomethane projects present to decarbonise, there is only one project capturing and injecting biomethane into the gas grid in Australia at present.

FFCRC projects RP1.2-04 and 1.2-06 have focussed on identifying the critical barriers and opportunities that impact the investability of biomethane grid injection projects in Australia, to support the development of the industry. Two tools that explore different aspects of economic viability have been developed, one focussed on how viability varies across Australia due to feedstock locations and critical infrastructure, and another that focuses on how to more optimally run a biomethane plant, to ensure more 'bang for buck' given available feedstock. Having co-designed the tools with the industry team on this project, both tools allow users to understand the effect of key assumptions about feedstock availability, as well as potential government policies that can increase the investability of these projects.

The first tool is a spatial tool that allows users to undertake an assessment to identify the most investable sites across Australia. The tool combines layers of data including energy from feedstock, cost parameters, emissions and pipelines. Using costing equations developed as part of this research, the levelised cost of energy (LCOE) can then be estimated at each 5 x 5km location, assuming all feedstock in a collection radius is used (Figure i). This assessment focussed on the opportunities from agricultural waste, but importantly this does not include opportunities from wastewater treatment plants, food processing facilities, landfill and other sources. This tool can therefore also be used to identify what levels of policy support are required to enable commercially capturable biomethane in each state. Our research suggests that direct policy support, such as a feed in tariff in line with that used in 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 for each project akin to the Contract for Difference (CfD) schemes the state governments have recently implemented for power and storage projects. In addition, a combination of revenue streams from the by-products of biomethane (gate fee, digestate profit and CO_2 profit) can 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 diversion to biogas facilities, and encouragement of circular uses of byproducts by removing barriers for digestate and CO_2 use.

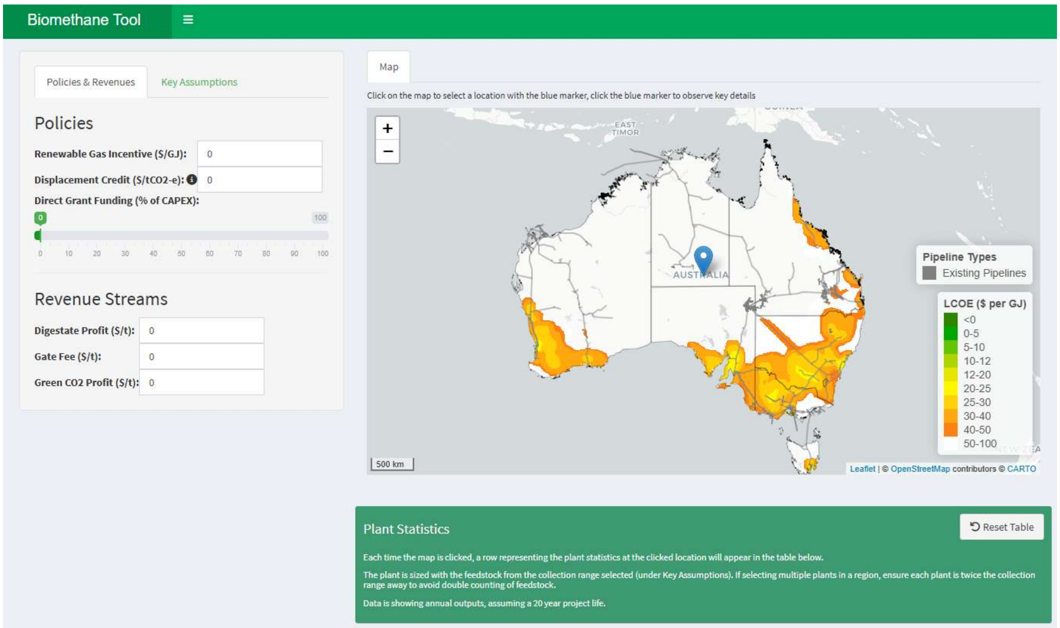

Figure i – The Online Mapping Tool

The second tool provides a project level focus on exploring which factors are most influential on the LCOE and carbon emissions mitigated through biomethane grid injection projects. With the major spatial factors 'fixed' for a given project location, the tool instead focuses on plant size and operation, types of feedstock available and revenue streams to offset cost (Figure ii). Similarly to the spatial tool, these assessments focus on a large-scale 'hub' style agricultural biomethane plant, accepting a variety of feedstock types. The tool provides the information needed by gas network owners to assess the techno-economic viability of injecting biomethane into gas networks, including resources required, byproducts produced, cost of production and carbon emissions mitigated.

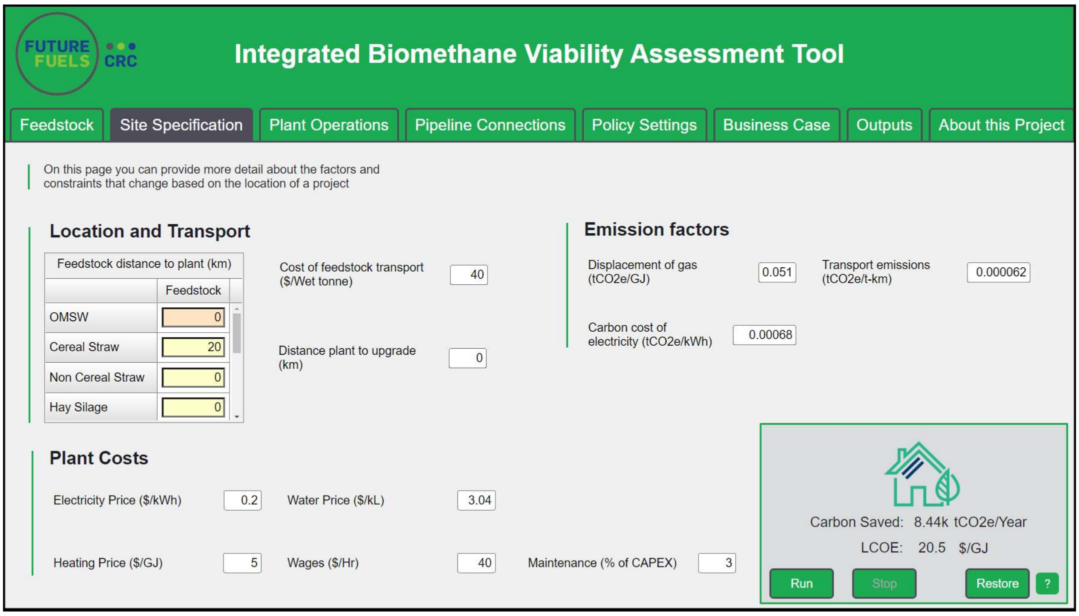

Figure ii – An example page of the project level Biomethane Viability Tool

Given the project level detail in this assessment tool, we were able to use the tool to perform a sensitivity analysis and identify factors that have the biggest impact on investability. Our research found that the factor the LCOE metric was most sensitive to was energy density, defined in this study as the gravimetric energy density, i.e. the GJ biogas from a tonne of dry feedstock. Smaller energy density values result in reduced biomethane production for a fixed transport cost of feedstock. The second and third most significant factors were feedstock availability and feedstock amount, respectively, which both also affect the size of the biomethane plant. In the case of feedstock availability, this is because the plant is sized to process all of the feedstock available in a given year, but either equally over twelve months of the year or all in just one month. The latter case would mean that the plant is underutilised eleven months of the year. In general, findings highlight that the energy content of the feedstock slurry is a key leverage point for projects, as relatively low-cost options such as pre-treatment and co-digestion can result in greater biomethane yields for the same fixed cost of feedstock transport.

1. INTRODUCTION

1.1 Background

The conversion of waste to bioenergy is regarded as an emerging opportunity to decarbonise energy systems in Australia, capable of meeting up to 20% of Australia's energy requirements by 2050 (Carlu, Truong et al. 2019, ENEA and Deloitte 2021). As gas delivers 44% of Australia's household energy, there is a significant opportunity to reduce greenhouse gas emissions while utilising existing gas networks with waste-to-gas schemes - specifically the production and injection of biomethane. Europe is the world's leading producer of biomethane, with 350 plants feeding into the gas grid in 2015 (Scarlat, Dallemand et al. 2018). Despite the opportunity and the significant commercial success in Europe, the production of biomethane and its injection into existing gas networks is currently almost non-existent in Australia.

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). While the high-level framework is able to provide guidance on how to perform the desired viability assessments and what potential data sources might be, it does not enable quantitative assessments to be performed. Consequently, the overarching objective of projects RP1.2-04 and RP1.2-06 is to develop user-friendly integrated assessment tools that enable the high-level framework to be applied easily and reliably by end users to identify the most investable locations and to perform viability assessments at these locations.

In Project RP1.2-04, two such tools were developed, the first a scanning tool designed to identify viable locations (based on most significant spatial factors) and also the total amount of bioenergy available in each state, and the second a project-level tool that allows users to explore the most significant levers that affect the levelised cost of energy (LCOE) of biomethane projects. This work was further developed in project RP1.2-06, where additional functionality was scoped by the industry team and added into the two tools.

The functionality added to the Online Mapping Tool includes:

- Interactive LCOE maps to allow users to zoom to and explore viable regions of Australia
- A summary dashboard that estimates how much energy is below a user-provided LCOE threshold, for exploring the effect of policy and revenue streams
- Additional policy exploration options, including ACCU estimation for displacement abatement

The functionality added to the Project-Level Biomethane Viability Tool includes:

- Updated costing estimates to reflect both recent data from Europe (where the market is significantly developed) and a translation of the equivalent costs in Australia, acknowledging the market here is not as mature
- Economies of scale in the Capital costs of a biomethane plant
- Treatment of oxygen and nitrogen if contained in the biogas mix (this is dependent on feedstock type)
- Additional policy exploration options, including ACCU estimation for conversion and displacement abatement

1.2 Purpose of this report

The purpose of this report is to present a summary of the major research findings of RP1.2-04 and RP1.2-06. The report first provides an overview of the two decision support tools developed in Section 2. Then, a user guide of both two tools is provided in Section 3 and 4. Finally, the key research findings from the application of each tool are presented in Section 5, with conclusions in Section 6.

2. OVERVIEW OF TOOLS

2.1 The Biomethane Assessment Tools

As part of project RP1.2-04 two tools were developed to support the transition to biomethane across Australia. These tools have been iteratively co-developed with the industry team supporting this project, which has improved their useability, and the clarity and accuracy of information presented.

The first tool - the Online Mapping Tool (Figure 1) - focusses on identifying the most investable locations for project development as the opportunities for biomethane as a renewable energy source are being made clearer across Australia. This tool is spatially explicit and enables users to undertake an assessment to identify the most investable sites across Australia. Given the acknowledgement that there are many barriers to investability currently, there is a focus on identifying the most commercially capturable sites in each state. The tool combines layers of data including energy from feedstock, cost parameters, emissions and pipelines. Using costing equations developed as part of this research, the levelised cost of energy (LCOE) can then be estimated at each 5 x 5km location, assuming all feedstock in a collection radius is used.

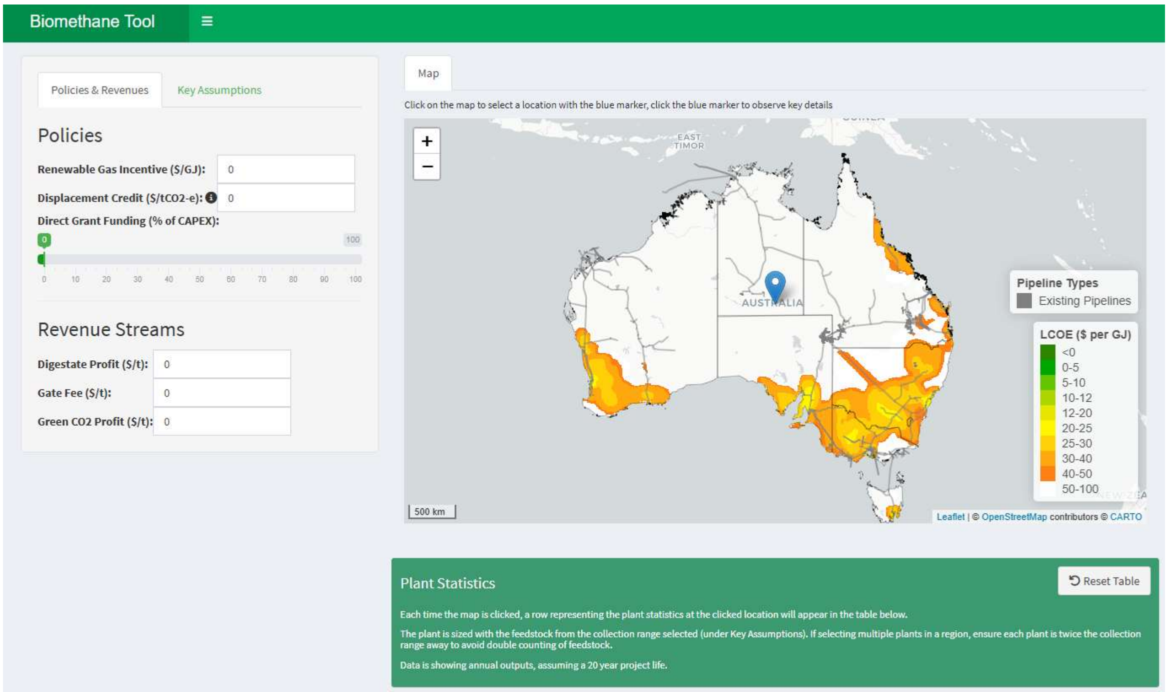

Figure 1 – Online Mapping Tool – a spatial assessment of commercially capturable biomethane in Australia.

The second tool – the Biomethane Viability Tool (Figure 2) - provides a project level focus on exploring which factors are most influential on LCOE and carbon emissions mitigated through biomethane grid injection projects. With the major spatial factors ‘fixed’ for a given project location, the tool instead focuses on plant size and operation, types of feedstock available and revenue streams to offset cost. The tool provides the information needed by gas network owners to assess the techno-economic viability of injecting biomethane into gas networks, including resources required, byproducts produced, cost of production and carbon emissions mitigated.

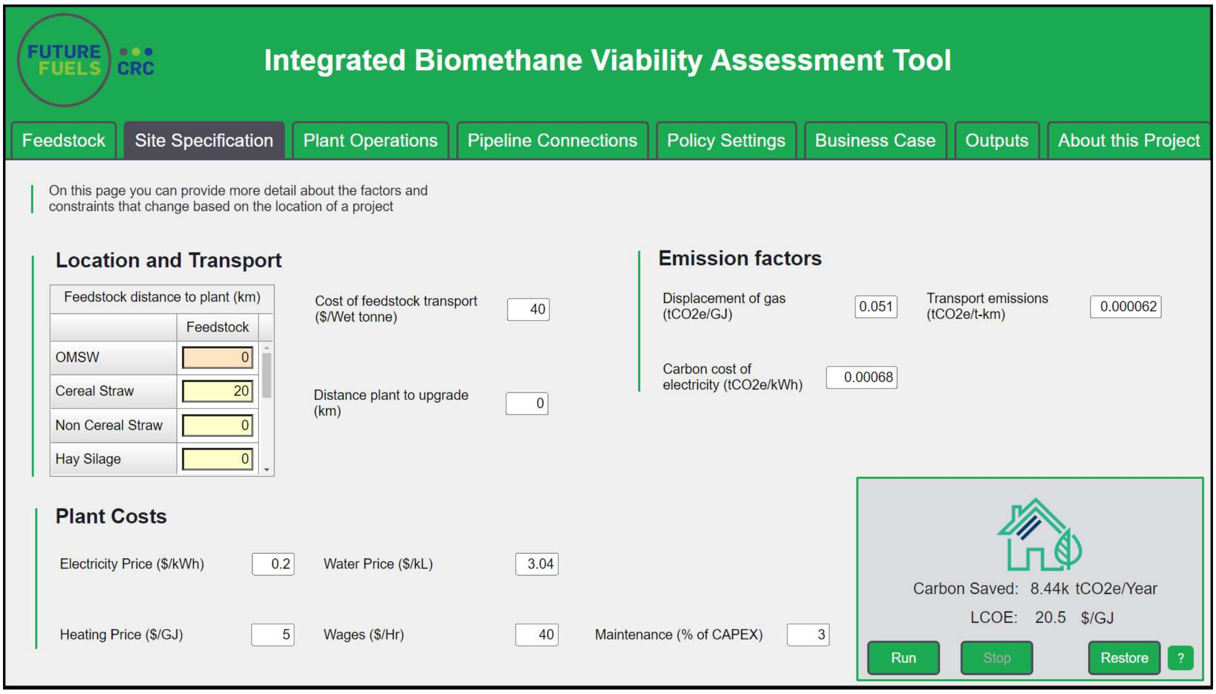

Figure 2 – Example page of Biomethane Viability Tool – a project-level assessment to explore the biggest factors that affect techno-economic viability

When first approaching the viability of biomethane projects in Australia, the two tools can be used together, to first provide an overview of a potential project site with the Online Mapping Tool and then explore how to better optimise plant viability and lower cost of production using the Biomethane Viability Tool. The Online Mapping Tool will provide an overview of required plant size (purple shading), how much feedstock is available (orange shading) and distances to pipeline (blue shading), which are all inputs of the Biomethane Viability Tool, as demonstrated in Figure 3.

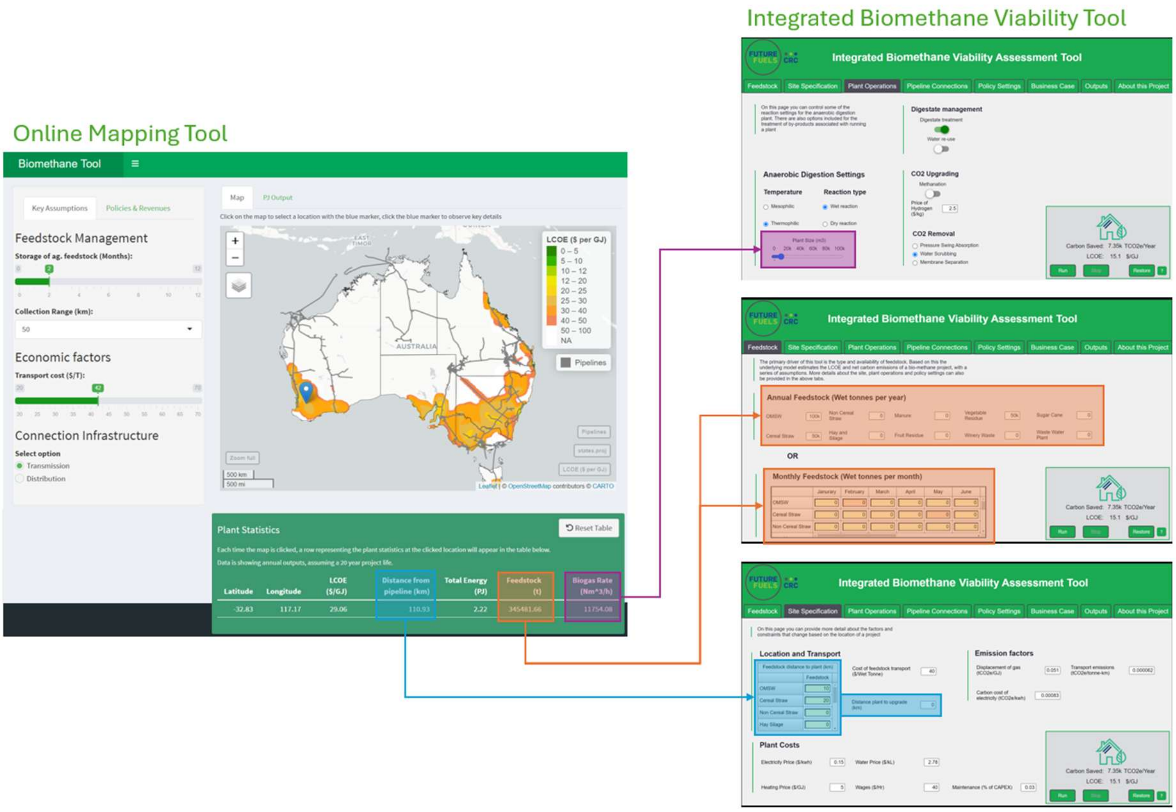

Figure 3: The Online Mapping Tool outputs inform the inputs for the Biomethane Viability Tool to provide a comprehensive assessment of first identifying key project sites and then further exploring how to improve viability and de-risk projects

2.2 Definition of investability

In this work, investability is defined as the expected profitability of investments in a biomethane project over the period of its 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 metrics: 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%. In select scenarios where a revenue stream is present (from selling byproducts or a government policy etc.), we adjust the standard calculation of LCOE to include the annualised net project costs, not total project costs. The primary reason for this is to acknowledge that revenue streams reduce the gap between the LCOE and the market price of natural gas so that projects can be profitable, allowing for a consistent comparison across the analysis. But it is important to note in these cases that the inherent cost of biomethane production is not changed. This modified LCOE metric will be denoted in the report using LCOE* and is measured in $/GJ, allowing for comparison with the purchase price of traditional fuels such as the price of natural gas.

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 used 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. Consequently, the net carbon mitigated metric from RP1.2-03/04 has been updated in RP1.2-06 to align with the calculation of conservation and displacement abatement specifically, as opposed to total net carbon emissions. Full details of these metrics can be found in Appendix A.

3. USER GUIDE: ONLINE MAPPING TOOL

Given the early stages of the biomethane industry in Australia, there is a real need to understand not just the theoretical upper limit on biomethane potential, but also which locations in Australia should be considered for potential projects. To better address this need, we have developed the Online Mapping Tool with a focus on identifying how much biomethane is commercially capturable in Australia. Crucially, the tool also allows the exploration of potential government policies, to understand how much additional biomethane they could bring online.

This section provides an overview of the Online Mapping Tool, with a particular focus on its functionality and how to re-assess the major findings of this project with different sets of assumptions. An overview of the high-level calculations is provided in Appendix B, with full details given in RP1.2-04 Report 1 and RP1.2-06 Report 2. The tool is available through the Future Fuels CRC website. The user guide for the Online Mapping Tool is split into four sections (Figure 4): the Navigation panel (Section 3.1), the User Inputs tab panel (Section 3.2), the interactive LCOE Map and Plant Statistics (Section 3.3) and the Energy Dashboard (Section 3.4). Each section is explained below for users to be able to use the tool.

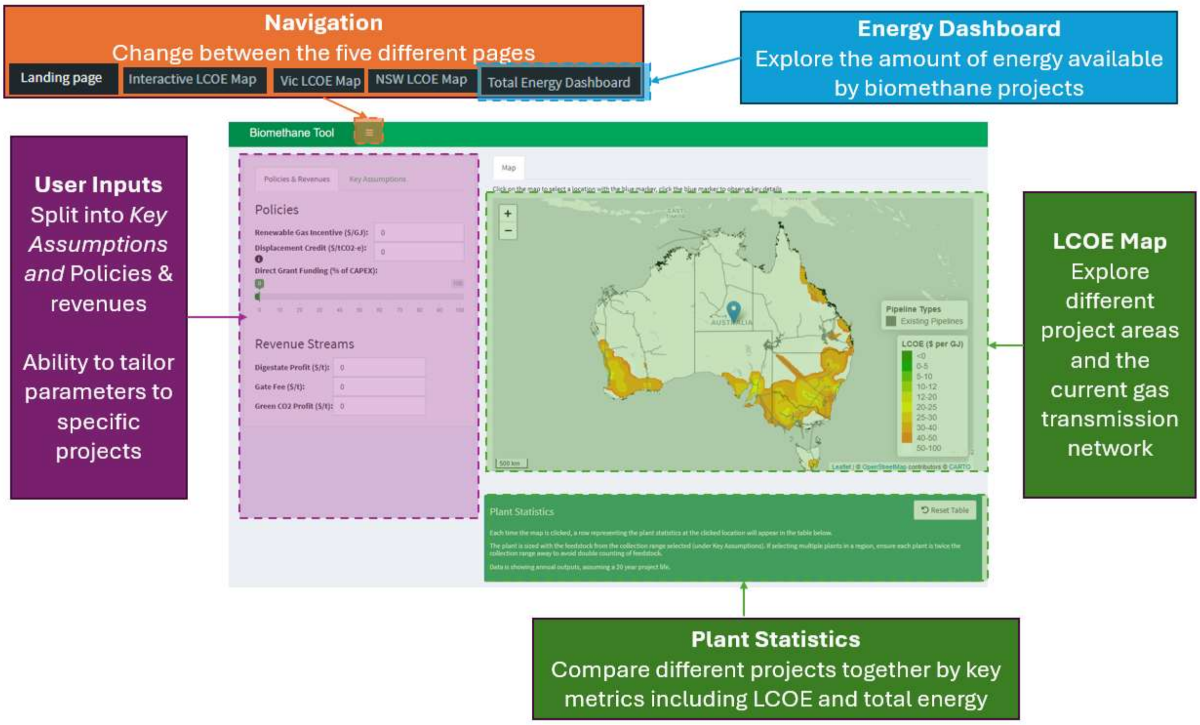

Figure 4: Overview of the Online Mapping Tool, split into the four sections; Navigation, User Inputs, LCOE Map and Plant Statistics, and Energy Dashboard.

3.1 Navigation Panel

This tab allows users to change between the four primary pages. When the tool is first launched users will begin on the 'Landing Page' (Figure 5). This page provides a high-level overview of the tool and outlines acknowledgement of project partners and other project support. Selecting the tab indicated in Figure 4 brings up the other key functionality of the tool: LCOE maps (one for the whole country, and one each for NSW and Victoria) and the Energy dashboard.

Figure 5: Landing Page of the Online Mapping Tool, with the navigation panel open.

3.2 LCOE Map and Plant Statistics – where are the most viable sites?

To explore where in Australia the most viable sites are located, the LCOE of a biomethane project is estimated at a 5 x 5 km scale across Australia. This estimate is based on available feedstock data and pipeline infrastructure locations (more details are in Appendix B). In this tool, the results of this assessment are displayed at the national level, as well as at a state level for NSW and Victoria. These states were scoped as being of particular interest to the project end users given the stage of industry development, and have therefore been separated for independent investigation.

For all three pages (National Map, NSW and Victoria), the LCOE is displayed in an interactive map, with colour grading to indicate the cost, and in particular in relation to the threshold of $12/GJ, under which a project would be economically viable. To investigate a particular area, the map can be zoomed in by clicking on the plus (+) and minus (-) symbols in the top left corner (Figure 6). Furthermore, the map also displays the current pipelines in Australia in grey. More information can be received about the pipelines by clicking on the pipeline of interest. By doing this a small box will appear on the pipeline displaying the name, length and owner of the pipeline (Figure 6). The map can also be clicked to display more information, with a blue marker appearing. The blue marker can be clicked and key plant properties of latitude, longitude, LCOE, distance to pipeline and total energy output of the plant will be displayed in a small box on top of the blue marker (Figure 6). The statistics refer to placing a biomethane plant at the exact location of the blue marker. There is a small 'x' on the right corner of the box to close the information.

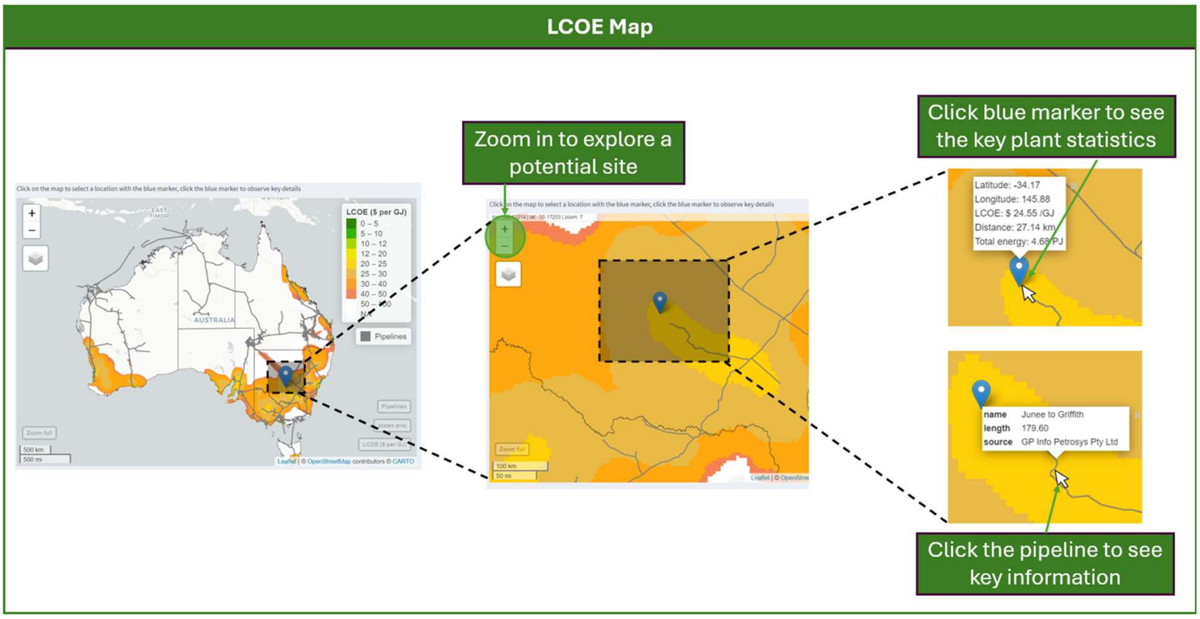

Figure 6: Functionality of the LCOE Map in the online mapping tool

Along with the blue marker when clicking on the map, a more detailed set of plant statistics is also made available in a table under the LCOE map (Figure 7). Note this functionality is only in the National Map Page. The row of data will contain key information about the plant including the LCOE, Distance from pipeline, Total energy, Feedstock and Biogas Rate (Figure 7). These outputs were selected as they are key information in further exploring the project level viability of a project. As more sites are selected on the map, they will appear as new rows in the plant statistics table. The rows remain in the table no matter how many times the map is clicked, but can be cleared by pressing the *reset table* button (Figure 7).

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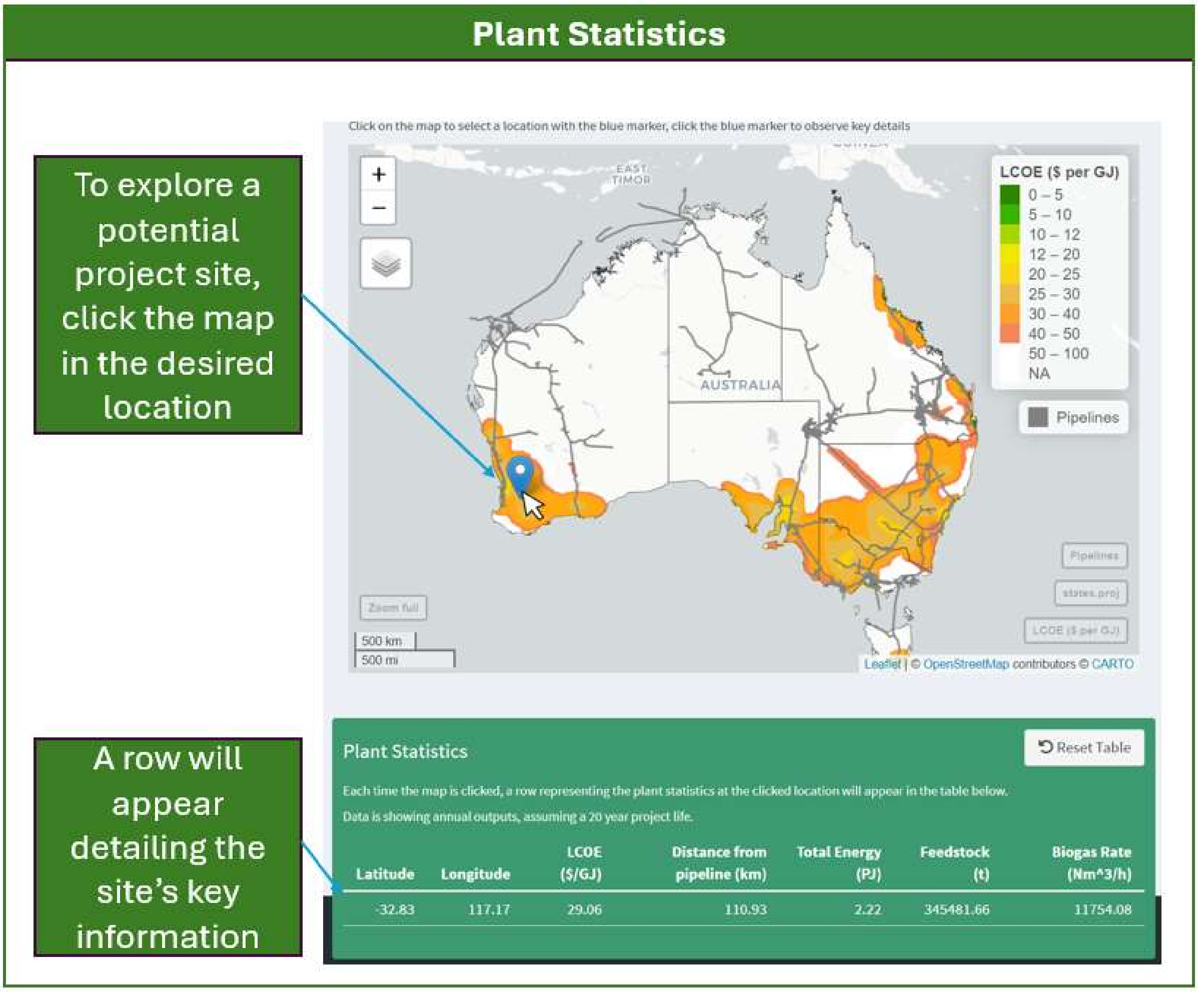

Figure 7: Functionality of the Plant Statistics in the online mapping tool

This interactive functionality allows for several different assessments into biomethane viability, including:

- Comparing viable sites across a state or nationally
  - See Figure 8 for an example of this.
- Building an estimate of a cost curve by selected successive projects.
  - Note that care needs to be taken here to include enough distance between projects such that feedstock is not double counted. See Section 5 for more information, which is a summary of Report 2 RP1.2-06.
- Comparing the effect of different policies and other assessment assumptions by selecting the same site but with different assumptions.
  - See Section 3.4 – User inputs for more information on what assumptions can be explored.

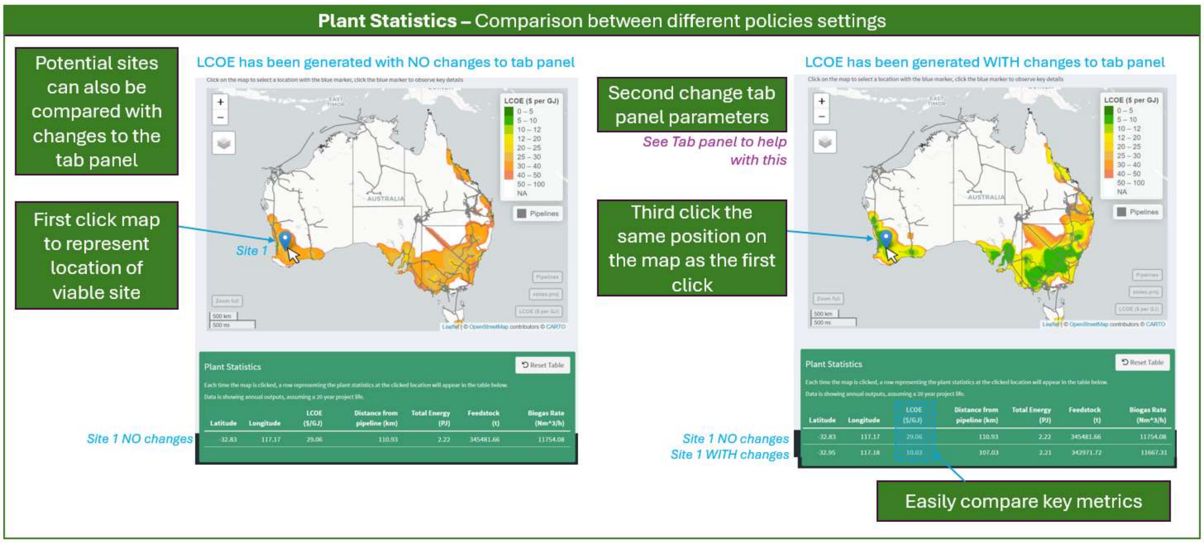

Figure 8: Steps to create a comparison between multiple potential project sites in the Plant Statistics functionality

3.3 Energy Dashboard – how much biomethane is commercially capturable?

With the LCOE estimated at each location, it is possible to estimate the total amount of biomethane that is commercially capturable, both nationally and for each state. To be able to explore this estimate, as well as how it might change as a result of policy implementation, the 'energy dashboard' page was developed (Figure 9). This page displays the amount of energy, in PJ, that can be generated by biomethane projects with a LCOE under the threshold value. The default value is $100/GJ to present an upper limit, but this can be changed by entering a new number in the input field (Figure 9). The amount of energy that can be generated by each state is displayed in the map of Australia. The national total of energy, as well as the carbon emissions displaced from injection of biomethane into the gas grid, are summed and displayed on the left side of the map. The energy and carbon emissions calculations will also change if an adjustment is made to any of the user inputs (Section 3.4), which allows policy makers to explore different levers and examine the change in commercially capturable biomethane.

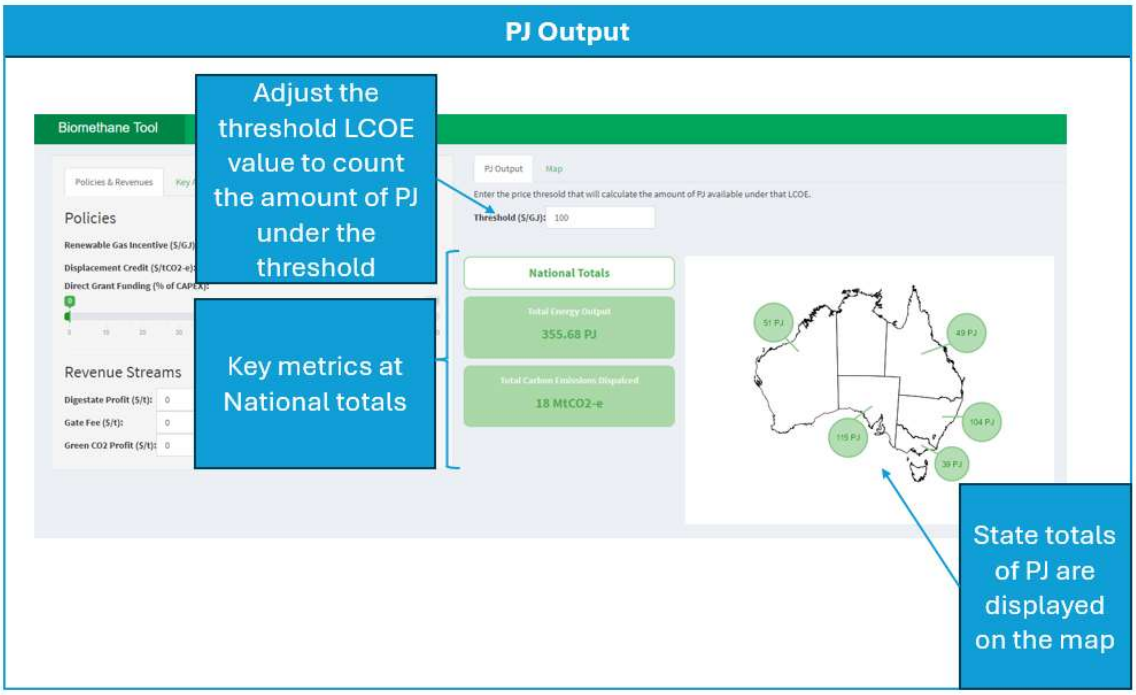

Figure 9: Functionality of the PJ Output in the online mapping tool

3.4 User Inputs

The estimate of LCOE of a biomethane plant, as well as the resulting estimate of commercially capturable biomethane, are both heavily reliant on a set of assumptions regarding plant size, feedstock availability and cost of transport of feedstock. Both estimates are also affected by potential policy and revenue support that is not assumed in the baseline LCOE calculation. To explore the impact of these assumptions, all pages of the tool have a user inputs panel.

The tab panel is situated on the left of the page, highlighted in purple in Figure 10. The tab panel allows for the users to adjust parameters and tailor variables to their location of interest. Any time a variable is changed, the tool will automatically recalculate and update its display. The tab panel is separated into two sets of parameters that heavily impact the viability of a biomethane project. The first page (which is currently displayed in Figure 10) is *Key Assumptions* involving parameters in the feedstock management, economic factors and connection infrastructure. The second user inputs page focusses on *Policies & Revenues* and involves different policies and revenue streams. These allow the exploration of the potential effect of different government policies and project support from sale of by-products. A full description of each of the variables that can be changed is displayed in Figure 11.

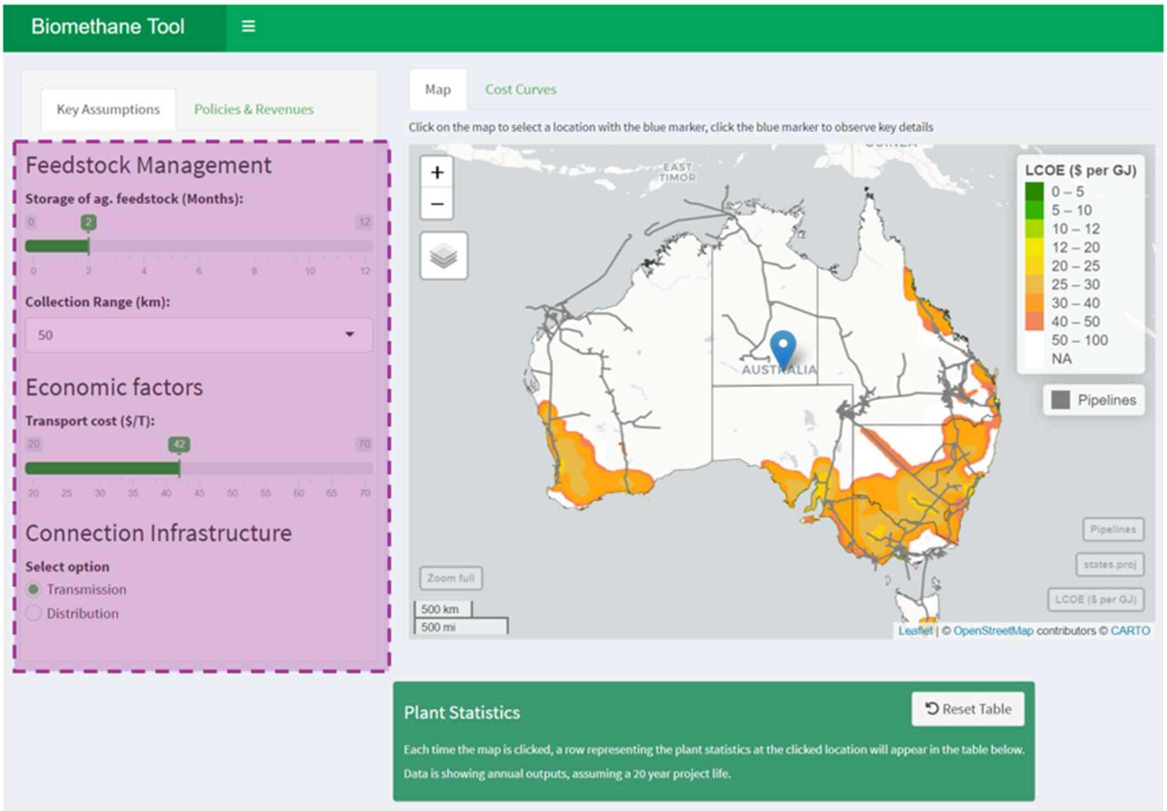

Figure 10: Tab Panel of the Online Mapping Tool highlighted in purple

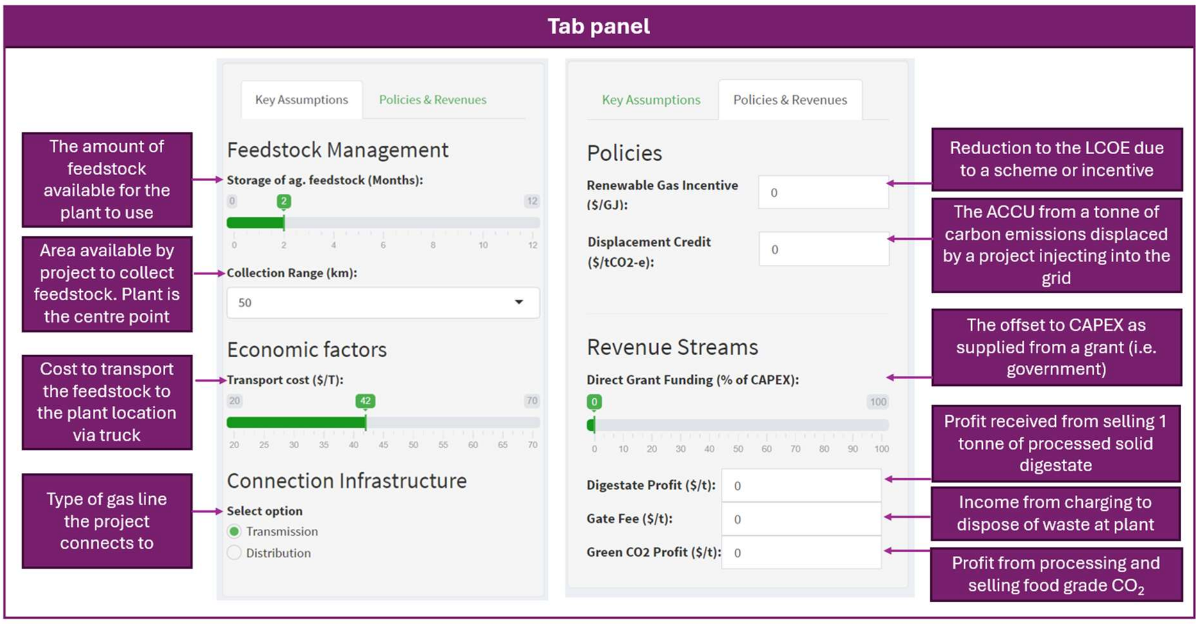

Figure 11: Descriptions of each variable in the Tab Panel

4. USER GUIDE: BIOMETHANE VIABILITY TOOL

In addition to understanding how viability varies across Australia due to spatial factors such as feedstock and infrastructure there is also a need to understand, at the project level, how viability can be improved. This is because without additional revenue streams or policy support, the cost of many biomethane projects is higher than the selling price of natural gas ($12/GJ) (note this is based on the agricultural, hub style plants investigated in our research). To address this gap, our research has also focussed on a project level Biomethane Viability Tool to understand the levers that affect project viability – both cost of production and carbon emission abatement.

The Biomethane Viability Tool is a detailed system dynamics model that tracks the underlying products as they move through the biomethane processes, and calculates costs, carbon emissions and other metrics throughout (See Section 2.1). A more detailed description of the underlying model is provided in Appendix C. To build the system dynamics model, Stella Architect software (isee systems 2020) was selected as the preferred approach, as it allows a front-end interface to be developed. This interface is linked to the underlying model and hosted online and can be accessed through the future fuels website[1].

The interface first provides some context for the project (see Section 4.1). Then, users can work through a series of pages in the interface to customise assumptions and parameters involved in the techno-economic assessment of biomethane projects (see Section 4.2). Finally, a high-level summary of the main outputs is provided (see Section 4.3). The categories included as part of the interface are as follows:

- Feedstock (how much and what type of feedstock is available)
- Site specification (how far is the feedstock from the proposed plant)
- Plant operation (how will the Anaerobic Digestion (AD) reactor be operated)
- Pipeline connection (what is the demand and injection pressure)
- Policy settings (what subsidies and tariffs are available)
- Business case (what are revenue streams and assumptions in cost/benefit)
- Outputs (gas produced, by-products and costs)

4.1 Model welcome and about pages

Upon launching the interface, users will see a description of the integrated assessment model, and a brief overview of the role renewable gas can play in the renewable energy transition (Figure 12). When pressing the “get started” button, users are brought to the main panels (Section 4.2), where they can interact with the pages listed above. The final page is called “About this project”, which provides a list of contributors to the project who have helped co-develop the integrated assessment model (Figure 13). This page also contains a link to a “model overview”, which provides a snapshot of the underlying model described in Appendix C.

[1] https://www.futurefuelscrc.com/

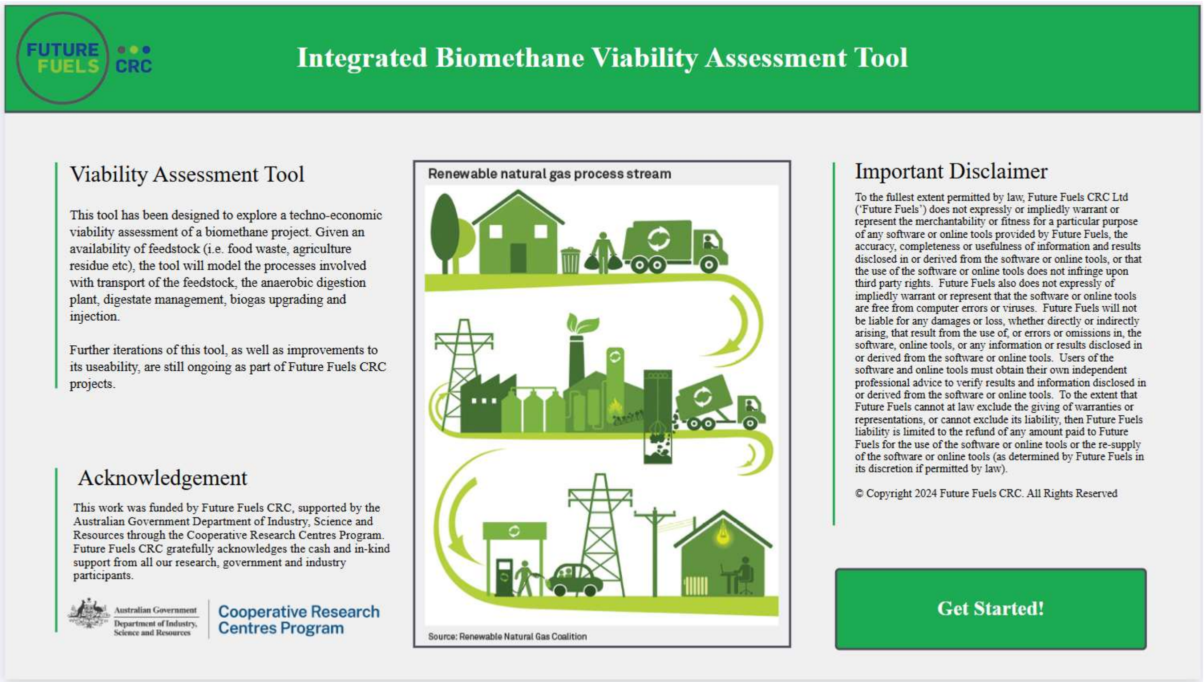

Figure 12: The front page of the interface for the Biomethane Viability Tool

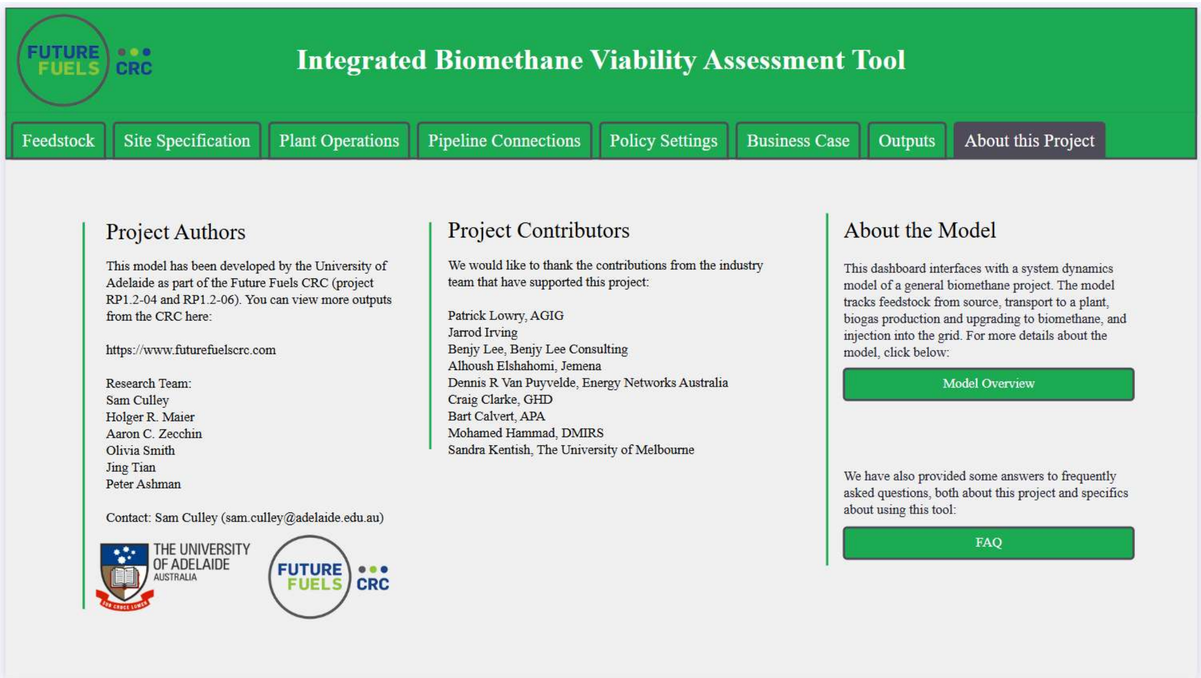

Figure 13: The about the project page for the Biomethane Viability Tool

4.2 Interfacing with the assessment model

The first page in the interface is the starting point for a techno-economic assessment, and a critical component to the success of biomethane projects, namely the feedstock that is available (Figure 14). Users have the option to enter the feedstock available in tonnes either annually, or if more information is known, at a monthly time step. This is particularly important for agricultural feedstock sources for which availability varies significantly through the year. Feedstock amounts are entered in dry tonnes, as this algins with much of the feedstock availability in the Australian Biomass for Bioenergy Assessment (ABBA) dataset (ARENA 2020).

On every page, there is also a quick summary of key techno-economic outputs (described in Section 2), and the ability to run the model. This is to allow a quick exploration of the high-level impact that change in a parameter has, without having to navigate to the outputs page. There is also an option to restore the model to default parameter values.

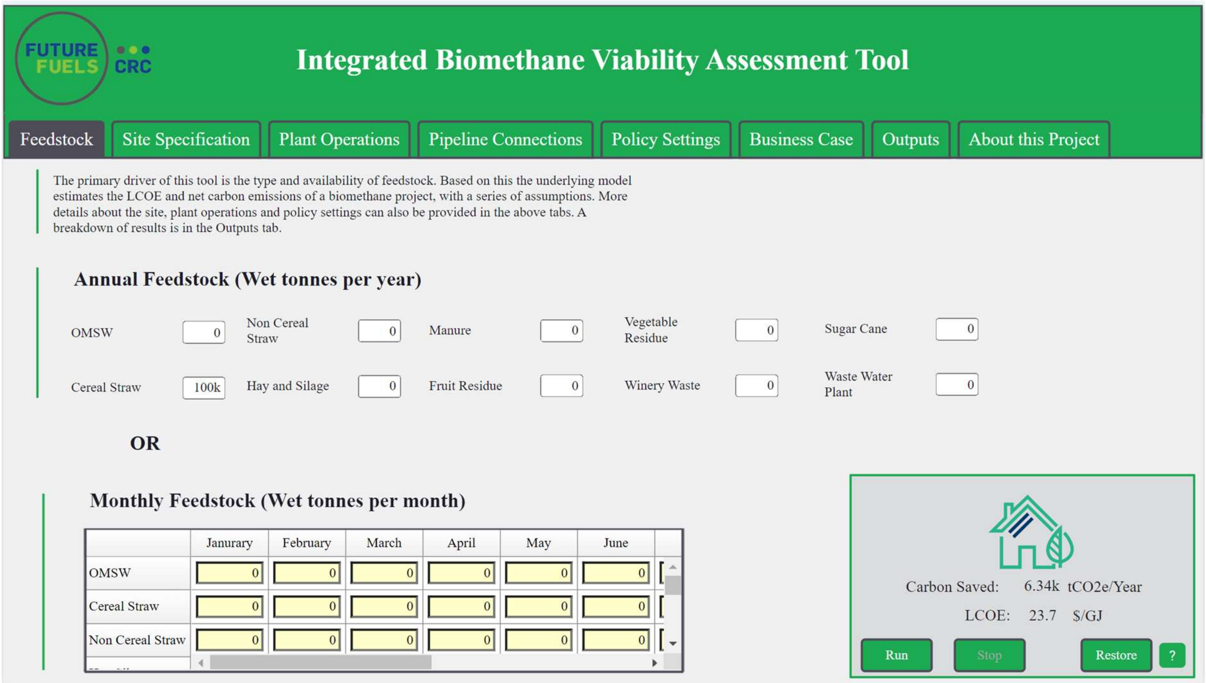

Figure 14: The feedstock input page in the interface

The second page allows users to change some of the details about the site where the project will be located (Figure 15). This is divided into three sections, location/transport, plant costs and emissions factors. The plant costs simply allow users to change the prices of electricity, gas, water, maintenance and wages at the site, which could vary based on state, provider, and also the extent to which more localised renewable power sources like wind and solar are used in the project. These values will be used to estimate the operation costs of the plant, given the energy and water requirements (details in Appendix C). The location and transport sections primarily refer to the distance between the feedstock source and the proposed plant. This is separated into different feedstock types to allow for a series of distributed plants. There are also separate costs of transport, which should be used to represent both the cost of transporting the physical waste and any purchasing or harvesting of waste residues required (e.g. collecting straw stems/chaff or manure). A further consideration for the feedstock availability, which should also be expressed in the transport cost inputs (in $/tonne), is the need to purchase waste due to market competitiveness. Emissions factors are also included to allow for the carbon estimates, as these vary by location.

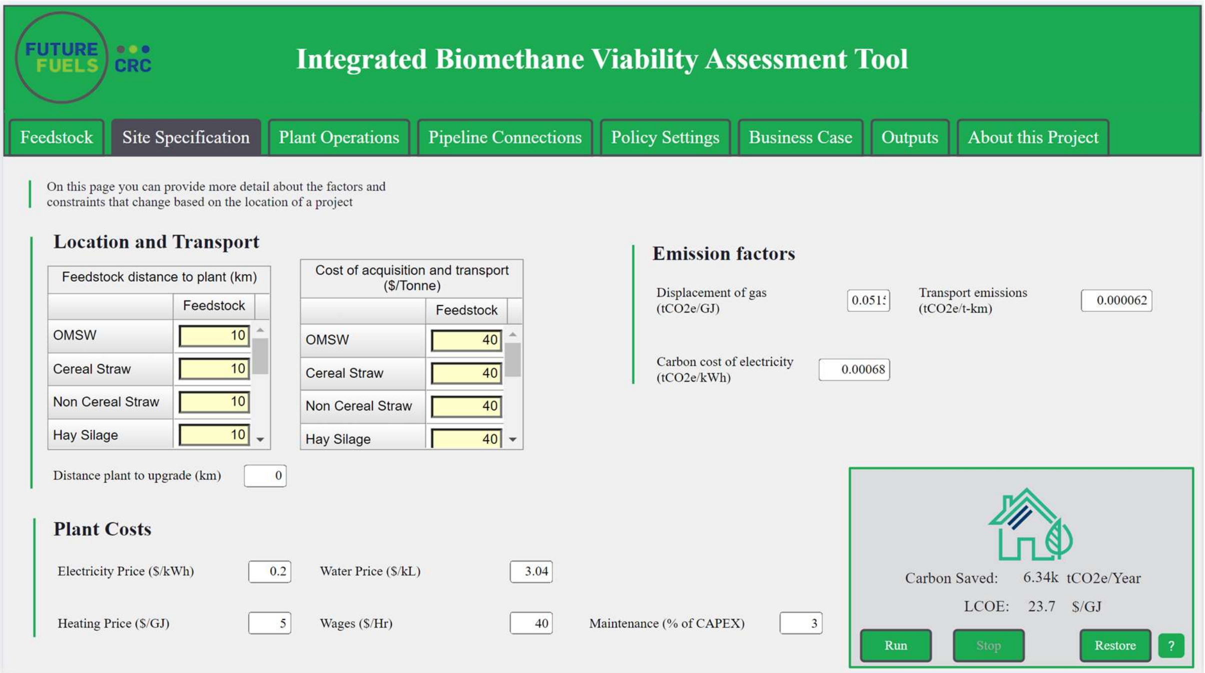

Figure 15: The case study specification page in the interface

The third tab is focussed on the operation of the anaerobic digestion plant (Figure 16). Users can control the configuration of three main areas: the anaerobic digestion reaction type, the method of isolating and removing carbon dioxide and handling of the digestate byproduct. The anaerobic digestion reaction settings can control the temperature of the reaction (supported data includes mesophilic and thermophilic reactions) and whether the reaction is wet or dry. These settings will require different levels of energy, heat and water but will also affect the resulting biomethane yields. The optimal LCOE can therefore be explored by changing between these options for any feedstock available.

Before biomethane is injected into the pipeline, the carbon dioxide needs to be removed from the biogas. Three methods are currently built into the integrated assessment model: pressure swing absorption, water scrubbing and membrane separation. Membrane separation is a newer technology, but is more efficient in treatment in that there is less biomethane slippage. Once this carbon dioxide has been separated, there is also the option to explore methanation (a process used to mix hydrogen with the carbon dioxide to create more biomethane). Whether this technology is economically viable will primarily depend on the price of hydrogen, which has been left as an input.

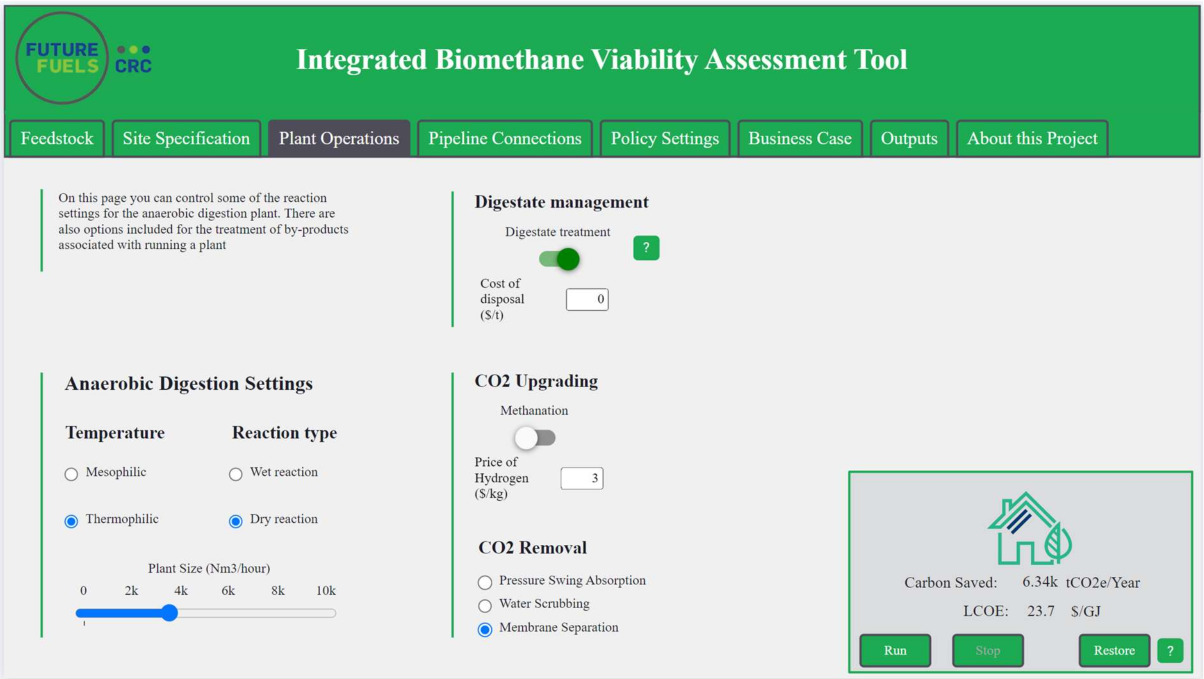

Figure 16: The plant operation input page in the interface

The fourth tab focuses on the connection to the gas network (Figure 17). At this point in the process, the biogas has been upgraded and is at specification for injection into the grid (based on AS4564). There are a few limiting factors at this point that have a significant impact on the overall viability of a project. The first of these is whether the project will connect to a distribution line or a transmission line. This will impact the connection pressure required, which can add significant costs to the project. The other is the demand for biomethane in the pipeline. In some areas of Australia, it will be possible to oversupply biomethane given the amount of feedstock available and the local demand for gas in a distribution network. In some cases, this presents a trade-off between having to pay higher costs for injection pressures, versus being able to provide biomethane in larger quantities. This should be explored for each case study, as a further advantage for higher injection pressure in transmission networks (beyond just increased demand) is the ability to store biomethane in the gas pipeline (line pack). This can help a project smooth out the oversupply of gas over short enough time periods. In the tool, if the biomethane exceeds the average gas demand it is instead flared.

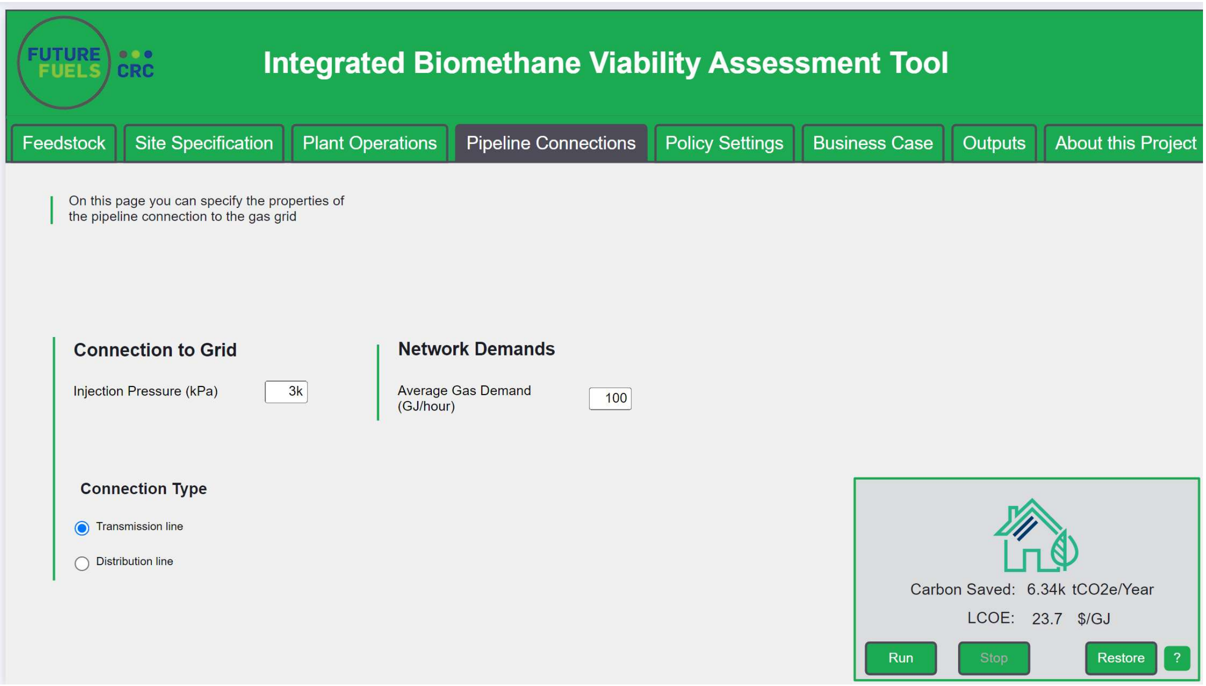

Figure 17: The pipeline connection page in the interface

The fifth and sixth tabs of the interface focus on the policy settings and business case parameters (Figure 18). The policy settings allow the exploration of two types of financial support: reductions to the capital costs of a plant, or a continuous income stream for the project. The reduction to capital cost is in the form of a onetime grant to offset CAPEX, which is meant to represent providers such as ARENA, as well as any state government funding. The income streams over time can be input in the form of a renewable heat incentive of some kind ($/GJ) based on gas injected into the grid, and also a carbon credit ($/T) based on carbon emissions avoided.

The first three inputs in this page are related to possible revenue streams. The first is a profit associated with selling the digestate produced as part of the anaerobic digestion. With some treatment, this can be used as fertilizer, and so the tool allows the exploration of a profit stream from the digestate to offset overall costs. The second is a gate fee associated with the delivery of feedstock. For some waste streams, waste levies are already being paid for disposal, which presents the opportunity to charge a fee for processing the waste at the anaerobic digestion plant. This essentially acts as an offset for the cost of transport. The final revenue stream considers any purchase of the CO_2 stream that is captured during biomethane upgrading. The final two business case parameters include the project life and discount rate, used to calculate the LCOE. In our assessments, these parameters default to 20 years and 7%, respectively.

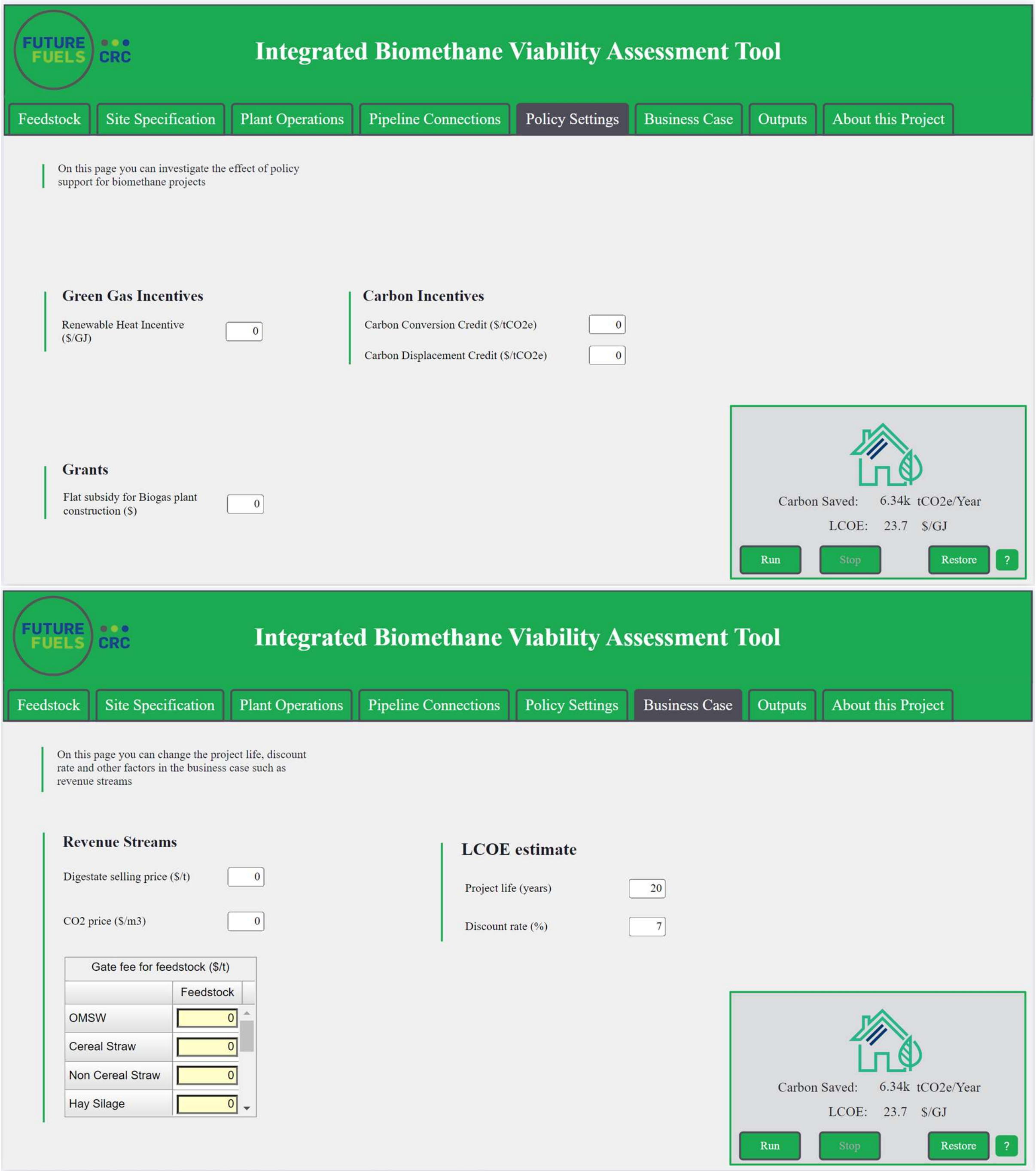

Figure 18: The policy setting and business case input pages in the interface

4.3 Outputs from the Biomethane Viability Tool.

The final page in the interface for the integrated assessment model is a list of outputs from the techno-economic assessment. These outputs are organised into a breakdown of:

- Costs;
- the volumes of biomethane produced;
- any by-products produced and finally; and,
- the materials required to operate the plant.

Costs are separated into capital and operational costs, with operational costs broken down and reported annually in the categories of: feedstock, transport, power, water, an estimation of wages and maintenance, and a sum of materials needed to upgrade the biogas (Figure 19). The biomethane production summarises the annual GJ produced from the feedstock, the annual amount injected (which will only be different if constrained by pipeline demand) and also an indication of any feedstock that was not processed. This term will indicate any feedstock that was delivered to the plant at cost, but not processed as it was greater than the size of the plant (and the maximum loading rate into an anaerobic digestor reactor) would allow. Its inclusion in the interface is to indicate that a larger plant size should be selected for the feedstock.

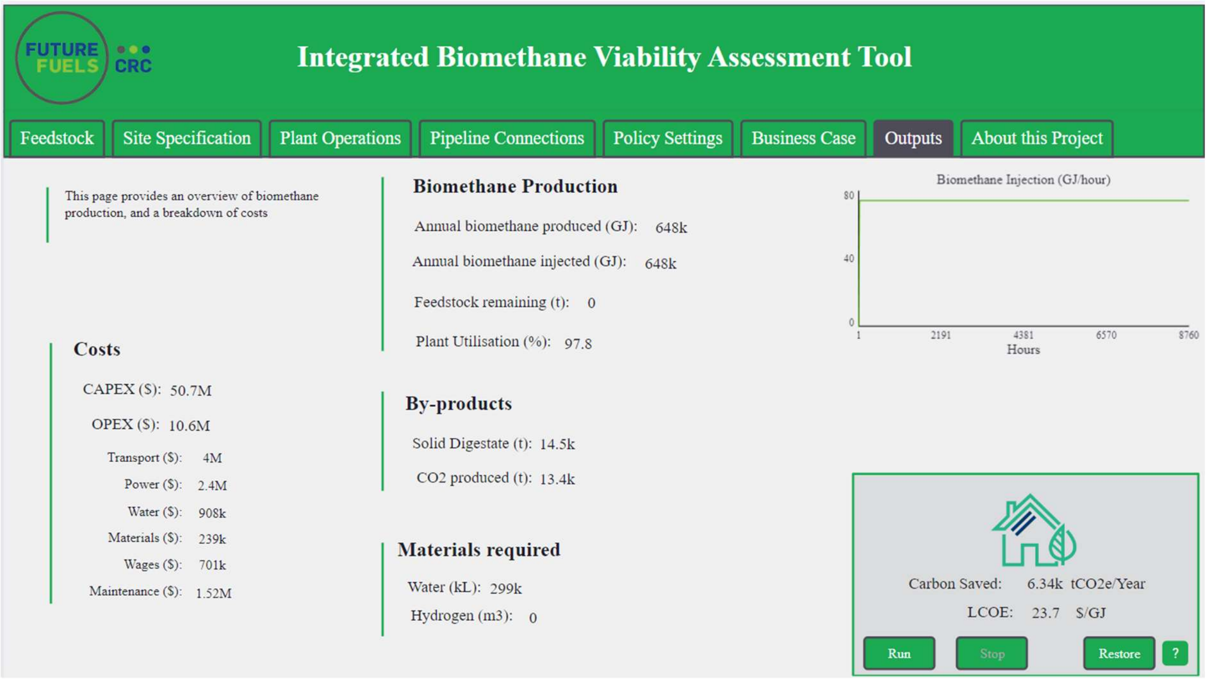

Figure 19: The output page in the interface

The by-products reported on in this assessment are the annual solid digestate and CO_2 produced, both expressed in tonnes. The digestate has commercial value as fertilizer in some applications, depending on the regulations present in the state for the proposed project. The green CO_2 can also have commercial applications, including in farming, as green fuels (such as methanol) and as a food grade product. Finally, the "materials required" section of the outputs track some of the other major resource streams required to run a plant, which will have an impact on where the project can be located (due to resource constraints). This includes the hydrogen that is used in methanation, and/or the water required, which will depend on the moisture content of the AD plant, and the feedstock types.

5. KEY FINDINGS FROM THE APPLICATION OF EACH TOOL

Research projects RP1.2-04 and RP1.2-06 utilised both the above tools to perform assessments that focused on main barriers and opportunities for biomethane projects in Australia. To understand how much biomethane is commercially capturable in Australia, the Online Mapping Tool was used to understand where the most viable sites are located, as well as the potential costs of the first 20 PJ in each state (Section 5.1). To understand the project-level factors that have the largest influence on both LCOE and net carbon emissions, the Biomethane Viability Tool was used to understand, for a given project, what the factors are that have the largest influence on both LCOE and net carbon emissions (Section 5.2).

5.1 Most investable sites and cost curves

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.

With the Online Mapping Tool, the LCOE (levelised cost of energy) for a biomethane project could be estimated at each point across Australia (Figure 20). Several assumptions about the type of project were made, including a 50 km 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. 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 20. 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 (ARENA 2020), 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).

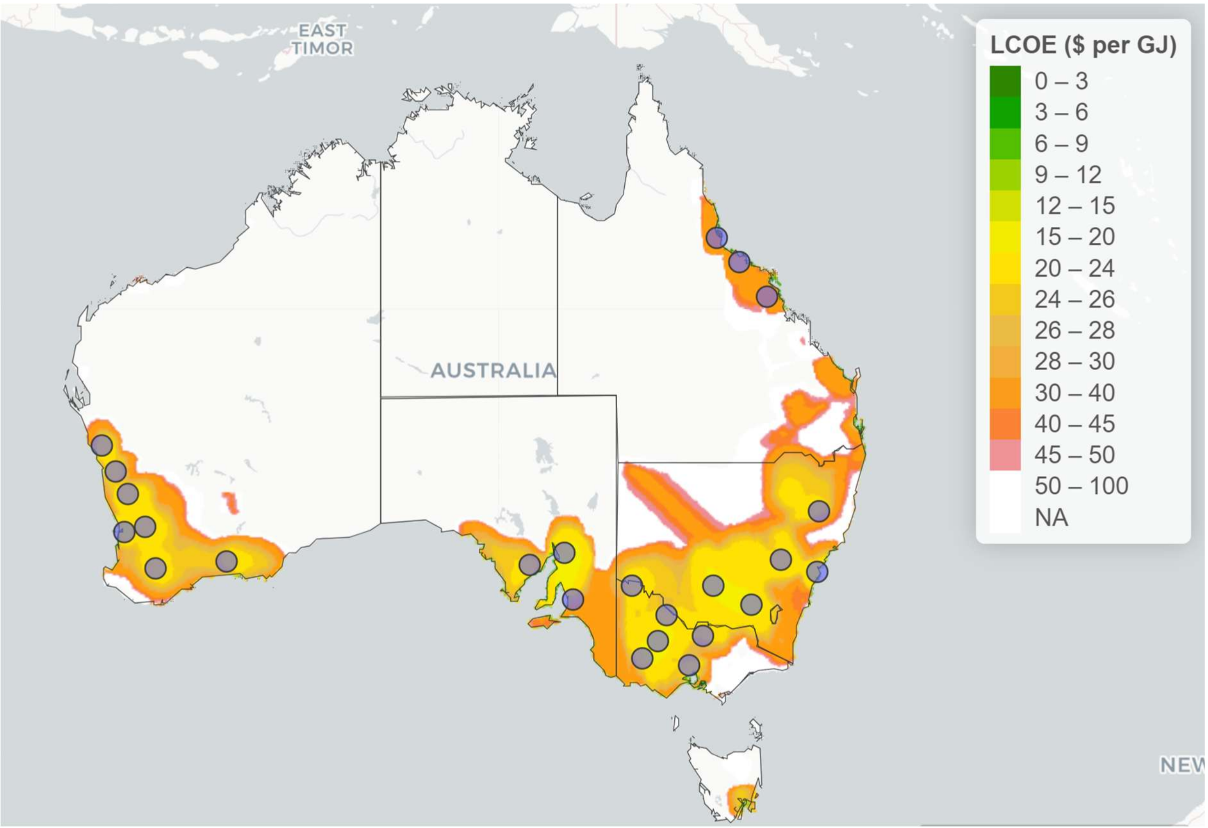

Figure 20: Selected sites to form the first 20PJ of biomethane grid injection projects in each state, with a heatmap of LCOE for production at each 5 x 5 km site in Australia

Taking the amount of biomethane available for each site, and the price, a summary cost curve was produced for each state (Figure 21). 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 1).

Table 1: Scenarios used 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 20 PJ 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 (which cereal straw has the largest plants) and plant utilisation (of which MSW and sugar cane have the highest year-round availability).

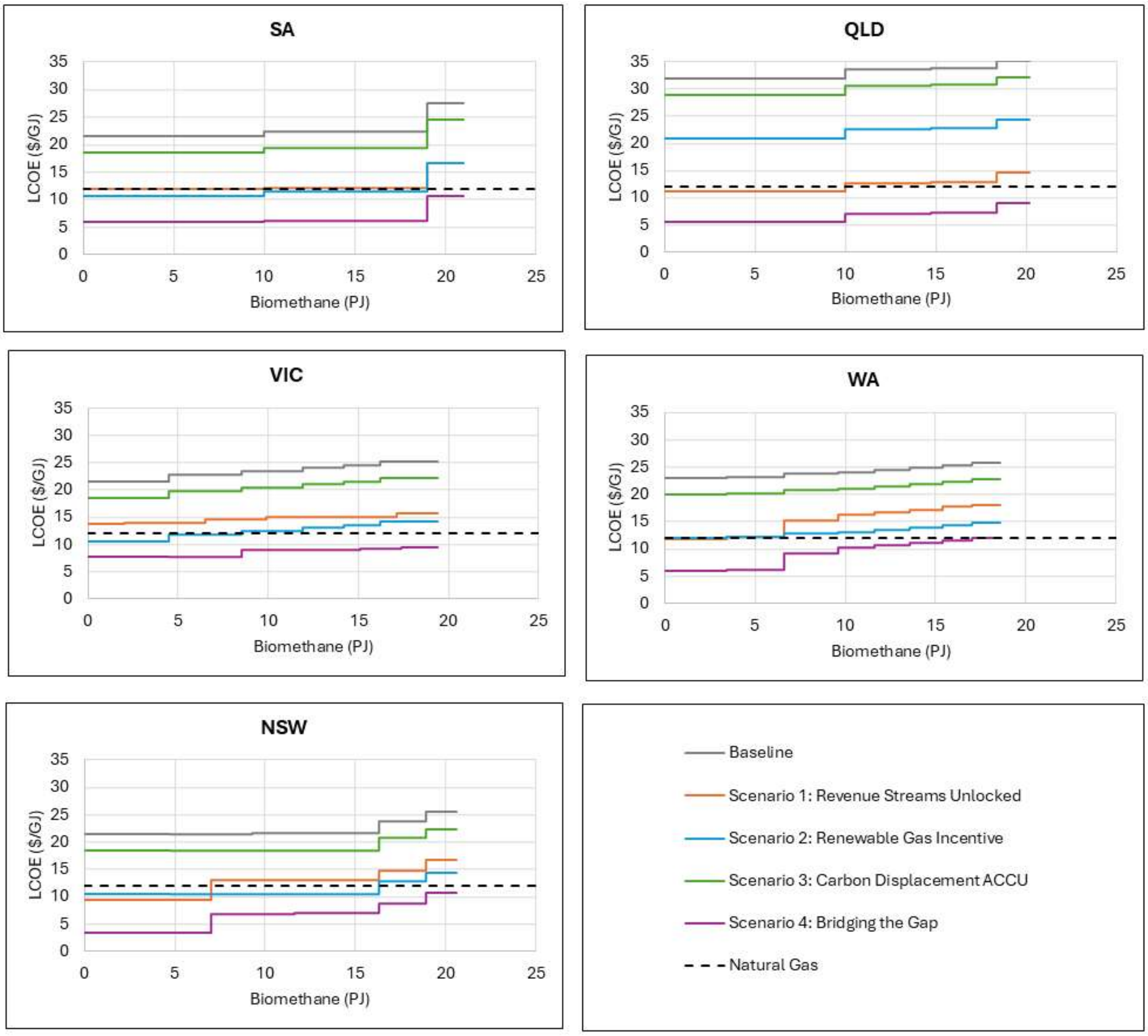

Figure 21: Cost curves of the first 20PJ of biomethane in each state. The coloured lines represent the four policy enabled scenarios

The effect of injecting into distribution, rather than transmission, lines was also considered, which can result in reduced transport distances, activating feedstock sources that are too far from transmission lines, as well as lower connection costs due to the reduced pressures in 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 20 PJ 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 distribution lines, we first limited the feedstock amounts to 10,000 T/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, these projects competitive compared with 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.

5.2 Most viable factors for biomethane projects

With biomethane projects receiving more attention and momentum across Australia, there is a need to understand the significant variability in the potential techno-economic viability of such projects. This variability can arise due to a combination of factors; some that are within the control of project stakeholders and others that are not, as they are caused by external forces. The former include type and location of plant, feedstock source etc., which should be optimised to maximise the chances of project viability. The latter include factors such as government support/policy, geopolitical instabilities, demand for gas from consumers, natural hazards such as droughts/floods and other market forcings, which need to be managed, especially if they have a significant impact on project viability. A sensitivity analysis was applied to the integrated biomethane project assessment model to provide a better understanding of the relative impact the above factors have on the viability of biomethane grid injection projects in Australia. The metrics for project viability used in this assessment are the levelised cost of energy (LCOE, $/GJ) and the net carbon saved (tCO_2-e).

As an example of the assessment performed, Figure 22 shows the sensitivity of both LCOE and net carbon saved to factors that relate to the source of feedstock and distance from the anerobic digestion (AD) plant. Full descriptions of these factors, as well the ranges of values considered for each of these factors as part of the sensitivity analysis, can be found in Appendix D of this report. As can be seen from Figure 22, the factors related to feedstock have a far bigger impact on both LCOE and net carbon saved than the factors related to distance from the plant. Feedstock availability has the largest impact on LCOE and net carbon saved, as this affects operational costs associated with transport and biogas upgrading, biomethane produced, and also the CAPEX of the required plant size (estimated from the peak biogas flow rate). The second most significant factor affecting LCOE is feedstock availability throughout the year, as this is essentially a proxy for feedstock storage, highlighting that fully utilising agricultural feedstock that is only available for one to two months a year is likely to be prohibitively expensive.

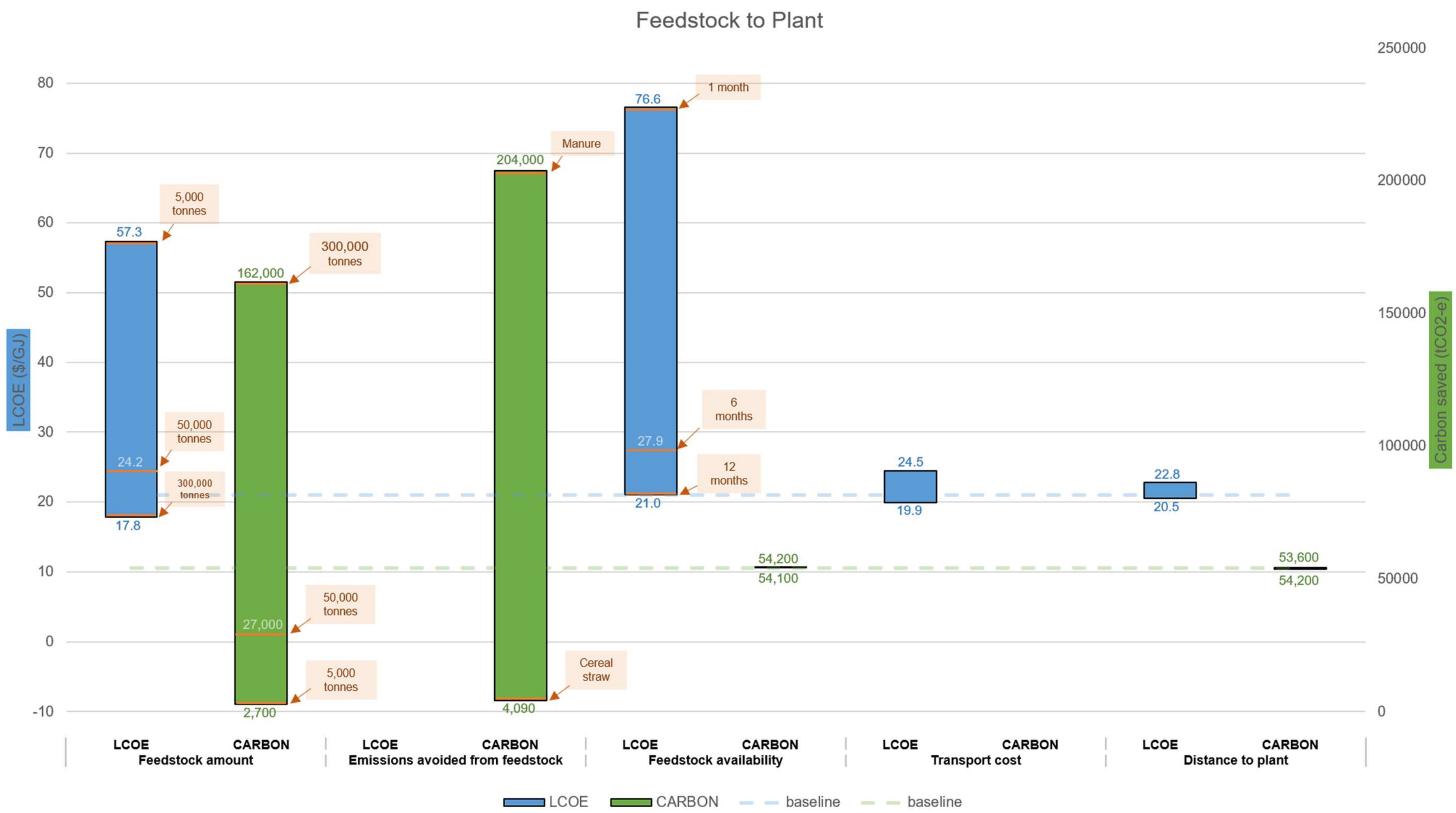

Figure 22: Sensitivity of LCOE and Net carbon saved to factors related to feedstock selection and distance from plant

A summary of the relative influence of all of the factors considered in this study on LCOE and carbon saved, ordered from most to least influential, is given in Figures 23 and 24, respectively. As can be seen from Figure 23, the factor LCOE is most sensitive to overall is the energy density of the feedstock. This factor controls the biomethane injected to the grid per tonne of feedstock transported to the plant and also determines the size of the plant for a fixed feedstock amount. As a result, smaller energy density values result in a lower plant capacity (with a relatively larger capital cost) and less biomethane offset for a fixed transport cost. The second and third most significant factors affecting LCOE are feedstock availability and feedstock amount (also shown in Figure 22), which both also affect the size of the biomethane plant. In the case of feedstock availability, this is because the plant is sized to process all the annual feedstock, which can be either over all twelve months of the year (if the feedstock is available all year round) or all in just one month (if feedstock supply is only available for a single month), resulting in plant underutilisation and prohibitively high costs, as mentioned above.

For net carbon saved, the two most significant factors by far are the emissions avoided from feedstock and the feedstock amount (Figure 24). These two factors inform conversion and displacement ACCU calculations, respectively. Both of these factors provide a strong motivation for biomethane projects with respect to waste re-use as part of creating a more circular economy, with the potential to save tens of thousands of tonnes of more carbon emissions depending on the feedstock type used. The third most significant factor affecting carbon emissions saved is the amount of biomethane injected vs flared (given network constraints), which has the effect of displacing less natural gas, as well as leading to bio-methane slippage into the atmosphere, and so the increase of flaring has a negative impact on the amount of GHG emissions that can be avoided.

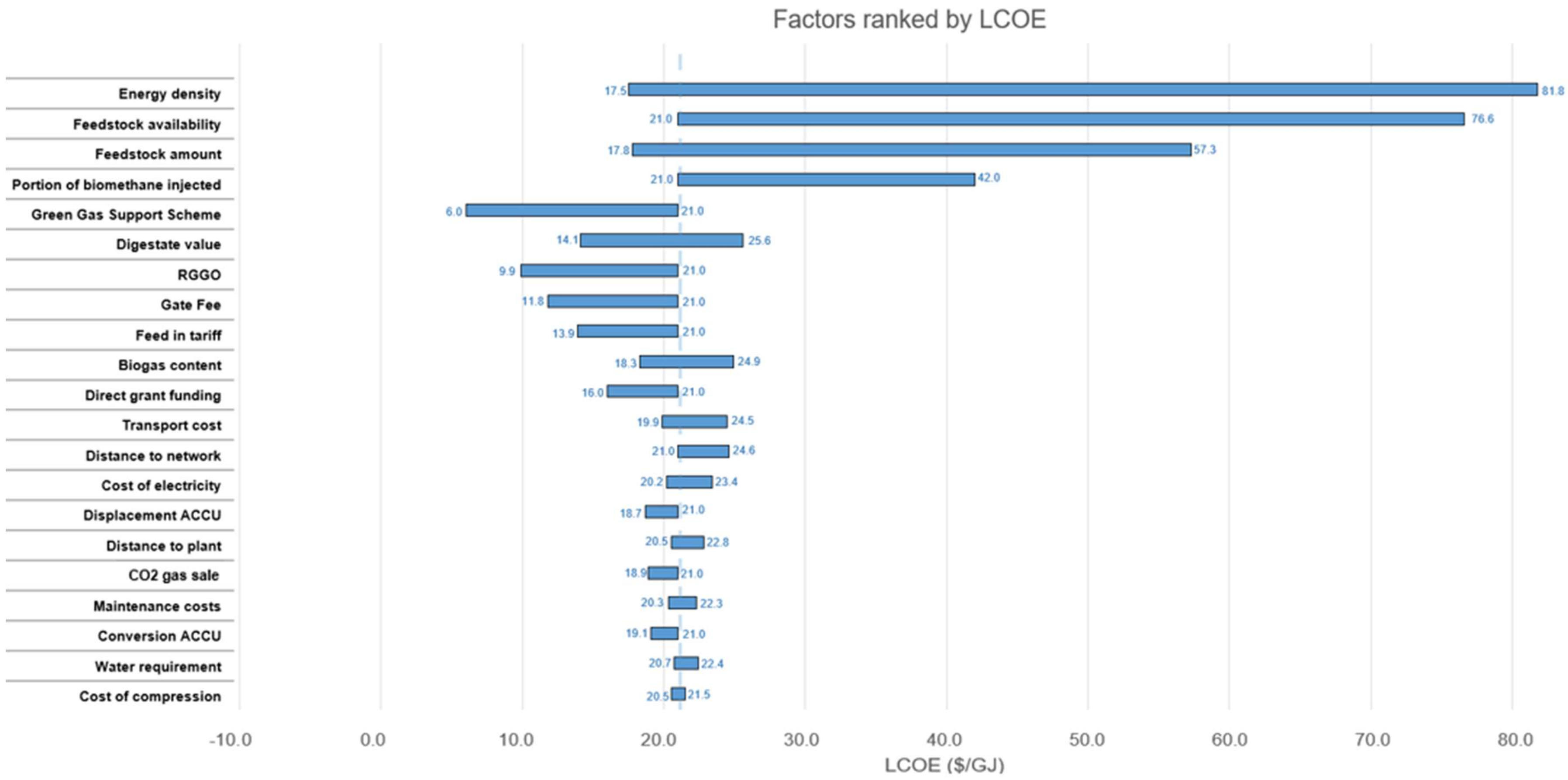

Figure 23: Ranking of how factors impact LCOE, with change presented relative to the baseline (the range taken for each factor can be found in Appendix D)

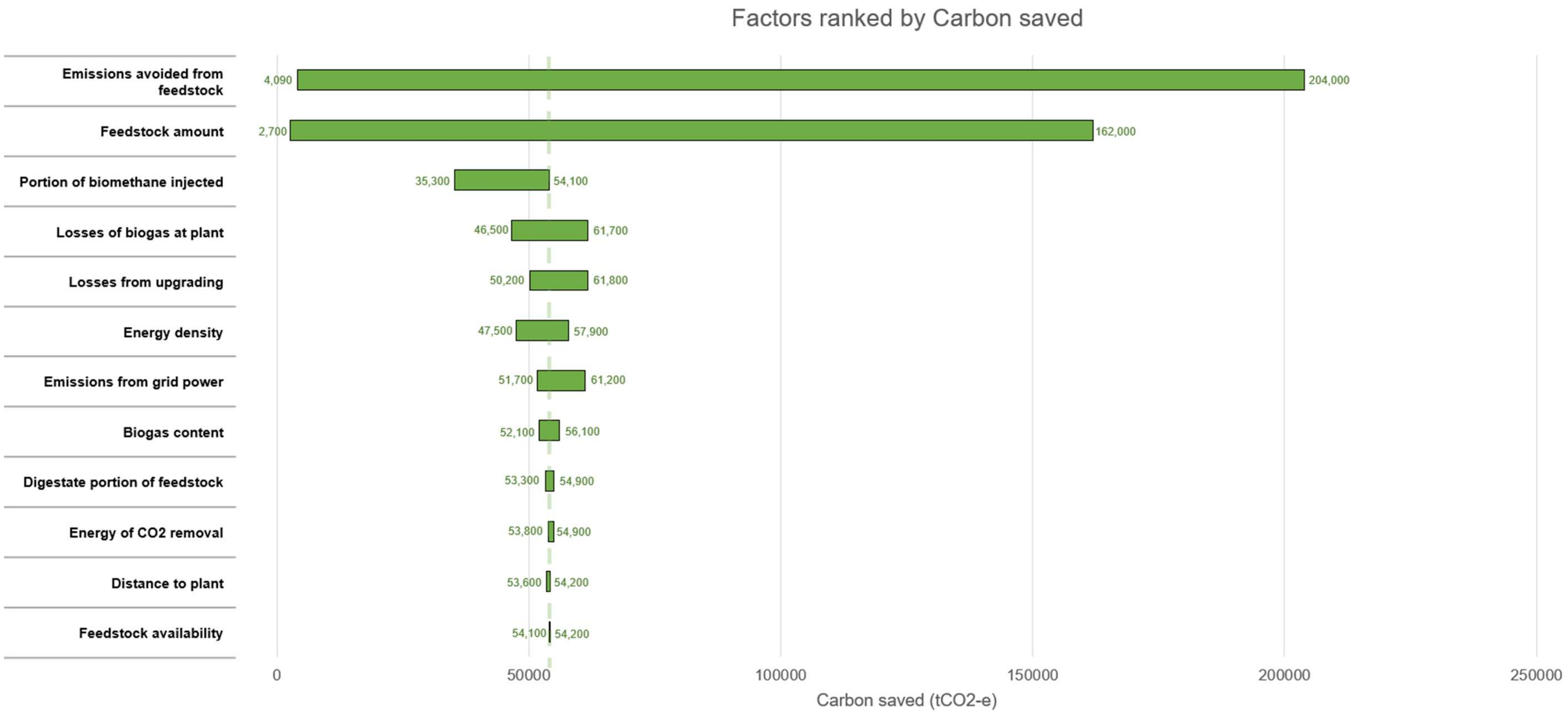

Figure 24: Ranking of how factors impact net carbon saved, with change presented relative to the baseline (the range taken for each factor can be found in Appendix D)

Finally, a series of joint sensitivities were considered to explore how closely the LCOE can approach the price of natural gas, when revenue streams and/or various favorable Government policies are in place (Figure 25), such as:

- **Renewable Gas Guarantees of Origin (RGGOs) + digestate profit**: This combination demonstrates the effects of a single policy support and revenue source, to compare with the price of natural gas.
- **Feed in Tariff (FiT) + grant**: This combination represents a policy scheme that is not solely reliant on FiTs but also includes capital support.
- **RGGOs + ACCU conversion**: This combination represents a carbon market with organisations purchasing RGGOs and also biomethane projects ACCUs.
- **CO_2 revenue + ACCU conversion + ACCU displacement**: This combination represents a biomethane project that has an emphasis on capturing CO_2.
- **CO_2 revenue + digestate profit + gate fee**: This combination represents the revenue streams that would be relevant with a strong circular economy focus.

The joint sensitivities of policies and revenue streams were investigated to examine which combinations lead the LCOE* to approach the price of natural gas (Figure 25). Of the five combinations examined, four resulted in LCOE* values that were less than the price of natural gas (taken as $12/GJ). Two of these include a RGGO scheme, which provides a heavy price offset, given the amount of biomethane produced ($40/MWh). The only policy combination to not reduce the LCOE* to values that are less than the price of natural gas is the one that focuses only on a carbon economy, where a credit of $60/t$CO_2$e for the conversion and displacement abatement, and sale of food grade CO_2, are not enough of a revenue stream for projects to have a positive NPV when selling biomethane at the price of natural gas.

When considering combinations of government policy and revenue support, the two lowest LCOE* combinations (at $2.97/GJ and $2.79/GJ) both consider a revenue stream from the selling of the digestate by-product. It is important to note that the profit available from digestate is highly uncertain due to several factors (e.g. limitations of use of digestate, market competition, and potentially having to dispose of the digestate at cost). When considering the values of a circular economy and combining the digestate profit with revenue from captured food grade CO_2, as well as the imposition of a gate fee, the LCOE* reduces to a value of $2.79/GJ. Alternatively, a FiT based on values from the Netherlands and other countries in the EU (One 2024), when combined with a once off $28,000,000 grant from Government agency funding (50% of CAPEX), reduces LCOE* values to $8.92/GJ, which is below the price of natural gas. If applied in Australia, this would increase the viability of large-scale agricultural projects, like the one modelled in the baseline of this assessment.

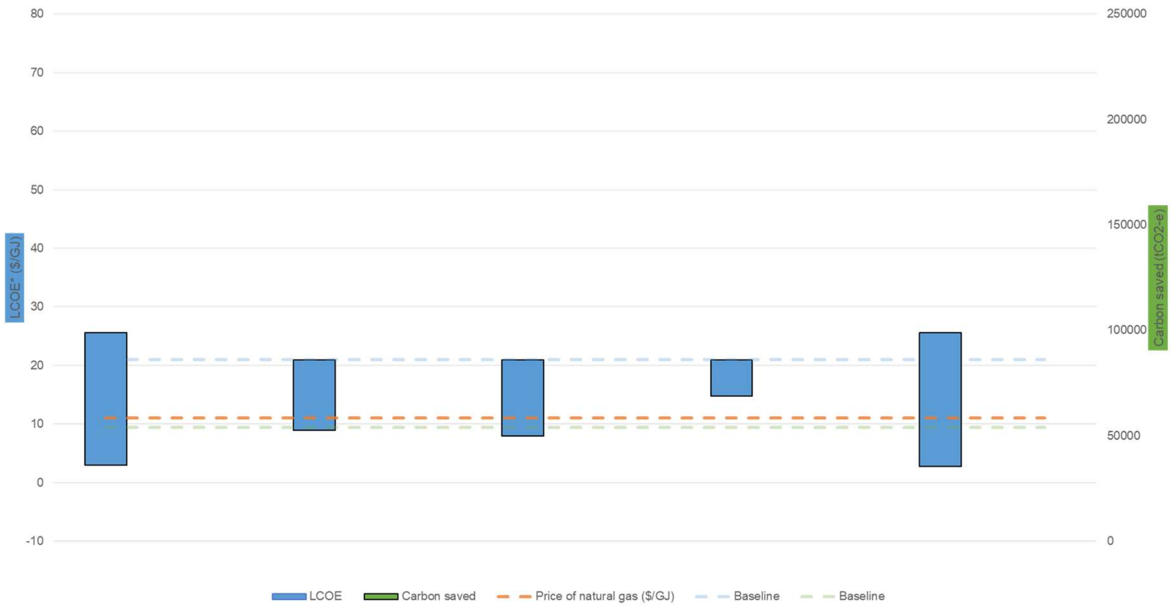

Figure 25: Joint sensitivity of LCOE to combinations of revenue and policies. Results are presented as change in LCOE from the baseline

6. CONCLUSIONS

Despite the clear need to decarbonise energy use in Australia, the pathway for heavy industry and other sectors remains unclear. One opportunity to decarbonise an industry currently reliant on natural gas are biomethane projects, already a proven technology in Europe and the US. This technology captures carbon emissions from organic waste (referred to as feedstock) to be an overall carbon abatement, and produces a fuel fit for use with existing infrastructure, such as gas pipelines for transport and demand side technology for end use. Despite the opportunity that biomethane projects present to decarbonise, there was only one project capturing and injecting biomethane into the gas grid in Australia at the time of writing.

FFCRC projects RP1.2-04 and 1.2-06 have focussed on identifying the critical barriers and opportunities that impact the investability of biomethane grid injection projects in Australia, to support the development of the industry. Two tools that explore different aspects of economic viability have been developed, one – the Online Mapping Tools - focussed on how viability varies across Australia due to feedstock locations and critical infrastructure, and another – the Biomethane Viability Tool - that focuses on how to more optimally run a biomethane plant, to ensure more 'bang for buck' given available feedstock. Having co-designed the tools with the industry team on this project, both tools allow users to understand the effect of key assumptions about feedstock availability, as well as potential government policies that can better enable the investability of these projects. In addition, research projects RP1.2-04 and RP1.2-06 have utilised both the above tools to perform assessments that focused on main barriers and opportunities for biomethane projects in Australia.

To understand how much biomethane is commercially capturable in Australia, the Online Mapping Tool was used to understand where the most viable sites are located, as well as the potential costs of the first 20 PJ in each state. Our research suggests that direct policy support, such as a feed-in tariff in line with Europe (~$11/GJ), makes approximately the first 10 PJ 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 Australian 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.

To understand the project-level factors that have the largest influence on both LCOE and net carbon emissions, the Biomethane Viability Tool was used to understand, for a given project, what the factors are that have the largest influence on both LCOE and net carbon emissions. Our research found that the factor the LCOE metric is most sensitive to is energy density, defined in this study as the gravimetric energy density i.e. the quantity of biogas from a tonne of dry feedstock. Smaller energy density values result in reduced biomethane production for a fixed transport cost of feedstock. The second and third most significant factors were feedstock availability and feedstock amount, which both also affect the size of the biomethane plant. In the case of feedstock availability, this is because the plant is sized to process all the annual feedstock, but either equally over twelve months of the year or on a month-by-month basis. The latter case would mean that the plant is underutilised. This means that the energy content of the feedstock slurry is a key leverage point for projects, as relatively low - cost options such as pre-treatment and co-digestion can result in greater biomethane yields for the same fixed cost of feedstock transport.

7. NEXT STEPS AND FUTURE WORK

This report is the final major milestone report for projects RP1.2-04 and RP1.2-06. The tools built as part of this project will be hosted online for an additional year past the close of the FFCRC. At this point in time further support for the tools will be required.

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> The study reviews and compares the most utilised techniques to obtain high quality biomethane by upgrading biogas from anaerobic digestion of the organic fraction of municipal solid waste. Environmental and economic aspects of membrane separation, water scrubbing, chemical absorption with amine solvent, and pressure swing adsorption have been quantified in a life cycle perspective. An attributional environmental Life Cycle Assessment has been implemented with the support of a Material Flow Analysis and in combination with a complementary environmental Life Cycle Costing. The analyses are based on data largely obtained from Italian existing plants but they can be generalised to the whole European Union, as demonstrated by a companion sensitivity analysis. The comparative assessment of the results indicates all the examined options as fully sustainable, also identifying the “win-win” situations. In particular, the membrane separation technique appears to have the best performances, even though in some cases with limited differences. With reference to base case scenarios, this technique shows better results for the respiratory inorganics potential (up to 34%, i.e. up to 328 kgPM2.5eq/y), global warming potential (up to 7%, i.e. up to 344 tCO2eq/y), and non-renewable energy potential (up to 12%, i.e. up to 6400 GJprimary/y) as well as for life cycle costs (up to 3.4%, i.e. about 60 k€/y). The performances of the examined techniques appear anyway dependent on site-specific conditions (such as the injection pressure in the gas grid or the existence/amount of local economic incentives) and commercial strategies for the market of interest.

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> Abstract The utilization of biogas produced from organic materials such as agricultural wastes or manure is increasing. However, the raw biogas contains a large share of carbon dioxide which must be removed before utilization in many applications, for example, using the gas as vehicle fuel. The process – biogas upgrading – can be performed with several technologies: water scrubbing, organic solvent scrubbing, amine scrubbing, pressure swing adsorption (PSA), and gas separation membranes. This perspective presents the technologies that are used commercially for biogas upgrading today, recent developments in the field and compares the technologies with regard to aspects such as technology maturity, investment cost, energy demand and consumables. Emerging technologies for small-scale upgrading and future applications of upgraded biogas such as liquefied biogas are also discussed. It shows that the market situation has changed rapidly in recent years, from being totally dominated by pressure swing adsorption (PSA) and water scrubbing to being more balanced with new technologies (amine scrubbing) reaching significant market shares. There are significant economies of scale for all the technologies investigated, the specific investment costs are similar for plants with a throughput capacity of 1500 Nm3 raw biogas per hour or larger. Biogas production is increasing in Europe and

around the globe, and so is the interest in the efficient use of upgraded biogas as vehicle fuel or in other applications. The market for biogas upgrading will most likely be characterized by harder competition with the establishment of new upgrading technologies and further optimization of the mature ones to decrease operation costs. © 2013 Society of Chemical Industry and John Wiley & Sons, Ltd

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> The production of methane by carbon dioxide hydrogenation through optimization of the operating parameters to enhance methane yield and carbon dioxide conversion in a two-stage fixed bed reactor is investigated. The influence of temperature, gas hourly space velocity (GHSV), and H2:CO2 ratio on the production of methane is studied. In addition, different methanation catalysts in terms of metal promoters and support materials are investigated to maximize methane production. The results show that the maximum methane yield and maximum carbon dioxide conversion are obtained at a catalyst temperature of 360 °C with a H2:CO2 ratio of 4:1 and total GHSV of 6000 mL h−1 g−1catalyst and reactant GHSV of 3000 mL h−1 g−1catalyst. The optimum metal-alumina catalyst investigated for CO2 conversion and methane yield is the 10 wt%-Ni-Al2O3 catalyst. However, reduction in the methane yield is observed with the addition of Fe and Co promoters because of catalyst sintering and nonuniform dispersion of metals on the support. Among the different catalyst support materials studied, i.e., Al2O3, SiO2 and MCM-41, the highest catalytic activity is shown by the Al2O3 catalyst with 83 mol% CO2 conversion, producing 81 mol% CH4 with 98% CH4 selectivity.

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> Anaerobic digestion has emerged as the preferred treatment for organic fraction of municipal solid waste. Digestate management strategies are devised not only for safe disposal but also to increase the value and marketability. Regulations and standards for digestate management are framed to address the pollution concerns, conserve vulnerable zones, prevent communicable diseases, and to educate on digestate storage and applications. Regulations and the desired end uses are the main drivers for the enhancement of digestate through pretreatment, in vessel cleaning, and post-digestion treatment technologies for solid and liquid fractions of digestate. The current management practice involves utilization of digestate for land application either as fertilizer or soil improver. Prospects are bright for alternative usage such as microalgal cultivation, biofuel and bioethanol production. Presently, the focus of optimization of the anaerobic digestion process is directed only towards enhancing biogas yield, ignoring the quality of digestate produced. A paradigm shift is needed in the approach from 'biogas optimization' to 'integrated biogas–digestate optimization'.

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Scarlat, N., et al. (2018). "Biogas: Developments and perspectives in Europe." Renewable Energy **129**: 457-472.

This paper presents an overview of the development and perspectives of biogas in and its use for electricity, heat and in transport in the European Union (EU) and its Member States. Biogas production has increased in the EU, encouraged by the renewable energy policies, in addition to economic, environmental and climate benefits, to reach 18 billion m3 methane (654 PJ) in 2015, representing half of the global biogas production. The EU is the world leader in biogas electricity production, with more than 10 GW installed and a number of 17,400 biogas plants, in comparison to the global biogas capacity of 15 GW in 2015. In the EU, biogas delivered 127 TJ of heat and 61 TWh of electricity in 2015; about 50% of total biogas consumption in Europe was destined to heat generation. Europe is the world's leading producer of biomethane for the use as a vehicle fuel or for injection into the natural gas grid, with 459 plants in 2015 producing 1.2 billion m3 and 340 plants feeding into the gas grid, with a capacity of 1.5 million m3. About 697 biomethane filling stations ensured the use 160 million m3 of biomethane as a transport fuel in 2015.

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APPENDIX A

In order to consider a more rounded business case, as mentioned, two metrics are considered as part of this assessment, one for cost and one for GHG emissions. The cost metric used is the Levelised Cost of Energy (LCOE), and the carbon metric is a measure of net Greenhouse Gas (GHG) reduction from the European Biogas Association (EBA 2020).

LCOE

The LCOE (measured in $/GJ) is estimated by calculating the total discounted lifetime costs (or, the net present value), divided by the total discounted energy output. In select scenarios where a revenue stream is present (from selling byproducts or a government policy etc.), we adjust the standard calculation of LCOE to include the annualised net project costs, not total project costs. The primary reason for this is to acknowledge that revenue streams reduce the gap between the LCOE and the market price of natural gas so that projects can be profitable, allowing for a consistent comparison across the analysis. But it is important to note in these cases that the inherent cost of the biomethane production is not changed. This modified LCOE metric will be denoted in the report using LCOE* and is measured in $/GJ, allowing for comparison with the purchase price of traditional fuels such as the price of natural gas. LCOE is calculated using the following equation:

Equation 1 – Levelised Cost of Energy

$$LCOE = \frac{I_0 + \sum_{t=1}^{n} \frac{M_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}$$

where, n = lifetime (years), r = discount rate (%), t = project year, I_0 = CAPEX (Capital Expenditure, $) amount, M_t = net cost in year t ($, note that in some relevant scenarios, we subtract revenue from costs), and, E_t = energy produced in year t (GJ). In this assessment, the sensitivity of LCOE to a range of factors will therefore be determined by their impact on the CAPEX and OPEX (Operational Expenditure) of running a biomethane project. However, the discount rate and project lifetime will also have a significant effect on the LCOE metric. This is explored more in Section 3.2.1, where the effect of these parameters on the baseline LCOE breakdown is demonstrated.

Net Carbon Saved

The method of estimating the carbon emissions adopted in this assessment is based on both the European Biogas Association (Figure 2), and the Australia emissions reduction fund calculations (Regulator; 2022). The greenhouse gas emissions reduction potential is estimated by taking the net difference between emissions caused from the project (transport of feedstock, flaring/leakage of gas, and emissions from grid power), and the carbon abatement (displacement of natural gas, avoidance of feedstock emissions and any avoidance from byproducts). In this study, the emissions tracked are as follows:

Carbon emissions:

- Transport;
- Carbon from electricity grid;
- Leakage from AD reactors;
- Leakage from biogas upgrading;
- Scope 3 fugitive emissions from gas networks;
- Leakage from incomplete combustion through flares (not in the baseline case, only when demand is limited).

Carbon abatement:

- Avoided from feedstock decomposition/prior use;
- Net abatement from digestate use instead of fertiliser;
- Displaced natural gas from grid.

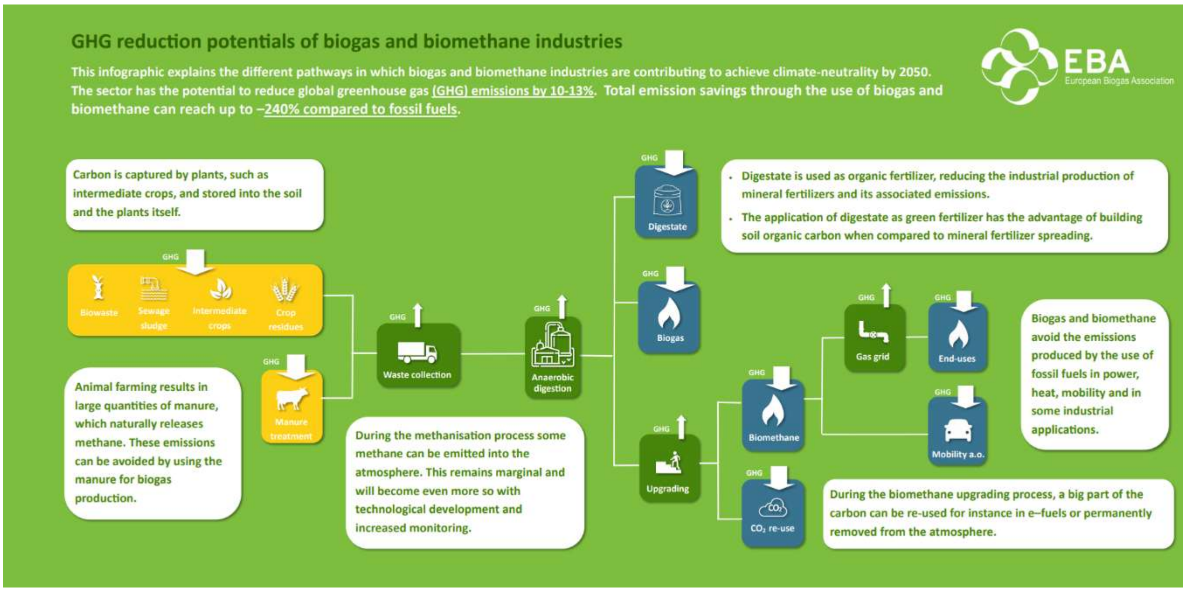

Figure 26 – GHG reduction potentials of biogas and biomethane industries ((EBA 2020)).

APPENDIX B

The Online Mapping Tool applies a spatial assessment methodology which uses several key data sources (available biomass, distance to pipelines and costing parameters) to develop a raster of spatial information on energy from feedstock, cost of transport, cost of production and cost of connection. This is reflected in Figure 27, 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).

The spatial assessment comprises of two sections, cost estimates which is all cost parameters involved to create a heatmap of LCOE, and the carbon emissions which calculates the emission both saved/avoided and released during the biomethane production (including transport and scope 3). Additions to the two sections have been made during RP1.2-06 to reflect new data gathered, as well as represent newly scoped processes in the online mapping tool. A summary of the cost estimates is provided in Section B.1, followed by the carbon emissions in Section B.2.

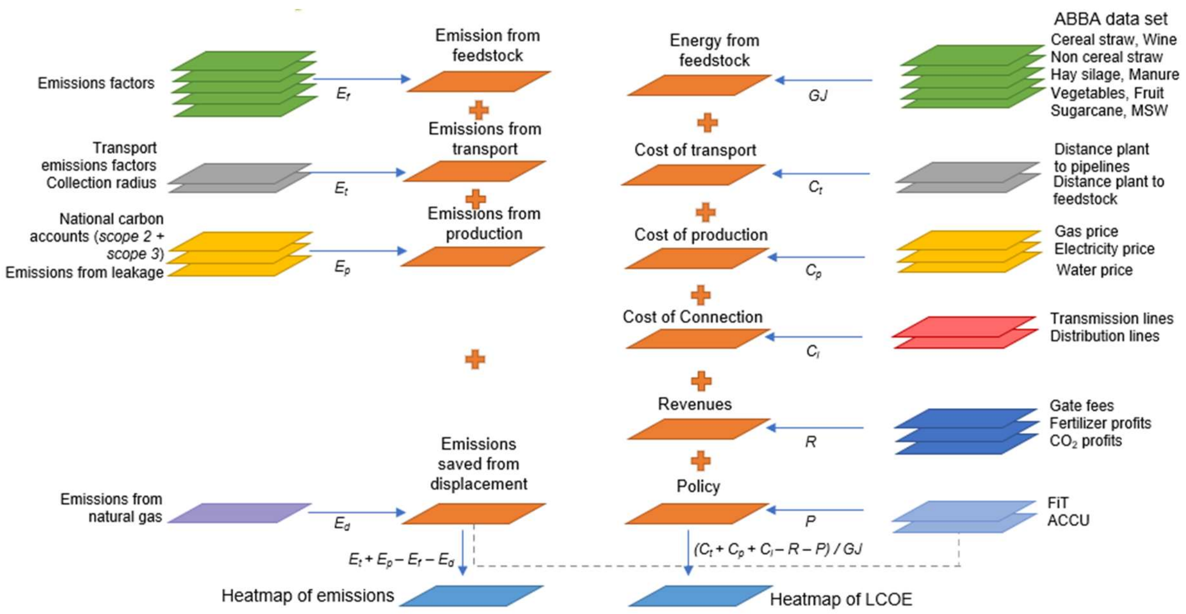

Figure 27: Spatial assessment methodology to identify the most investible sites in each state. The right-hand side consists of the costing estimates and the left reflects the emissions

B.1 Summary of cost estimates

The cost estimates combines 6 layers of data.

The energy from feedstock layer combines the ABBA data set illustrating the availability of feedstock spatially and the amount of energy generated dependent on the type of feedstock. This provides an estimate of the amount of GJ each spatial location can generate.

The cost of transport layer calculates the distance from the plant to pipelines and distance from the plant to feedstock. It is assumed that feedstock is transported via trucks based on $/t parameter, and biomethane is transported via pipelines based on $/km parameter. The pipelines 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. The locations of distribution lines have also been added, taken as point locations from the gas pipeline register[2].

The cost of production layer combines the costs of the utilities required in the production of biomethane. This includes gas price, electricity price and water price.

The cost of connection layer separates the distribution and transmission connection costs 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 the previous RP1.2-06 Report 1 (Figure 16 - Culley et al 2024).

Multiple options for Policy and other revenue streams were added as spatial layers (Figure 27) 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 was 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.

B.2 Summary of carbon emissions

The carbon emissions consist of three layers of data.

Emissions from transport is 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 average, which is assumed to be half the size of the collection radius (considering the plant is the centre point and the collection radius forms a circle, surrounding the plant). The transport emissions factors align with the ECTA guidelines for measuring CO_2 emissions (McKinnon 2007).

The emissions from production of biogas consist of scope 2 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 to upgrade the biogas, as well as scope 3 emissions in the gas grid.

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

APPENDIX C

The Biomethane Viability Tool is a detailed system dynamics model, which tracks the underlying products as they move through the biomethane processes, and calculates costs, carbon emissions and other metrics throughout. System dynamics modelling was selected as a suitable framework for the assessment as a series of stocks and flows allow a simple representation of a supply chain, the temporal dynamics of biomethane supply due to feedstock availability and actual gas demand in the pipelines can be directly modelled, and high level feedbacks and trade-offs can be readily explored. The Stella Architect software (isee systems 2020) was selected as the preferred approach for developing the system dynamics model, as it allows a very visual way to demonstrate the model (Figure 28), parameters can be changed easily, and the software supports the developed of a front-end interface.

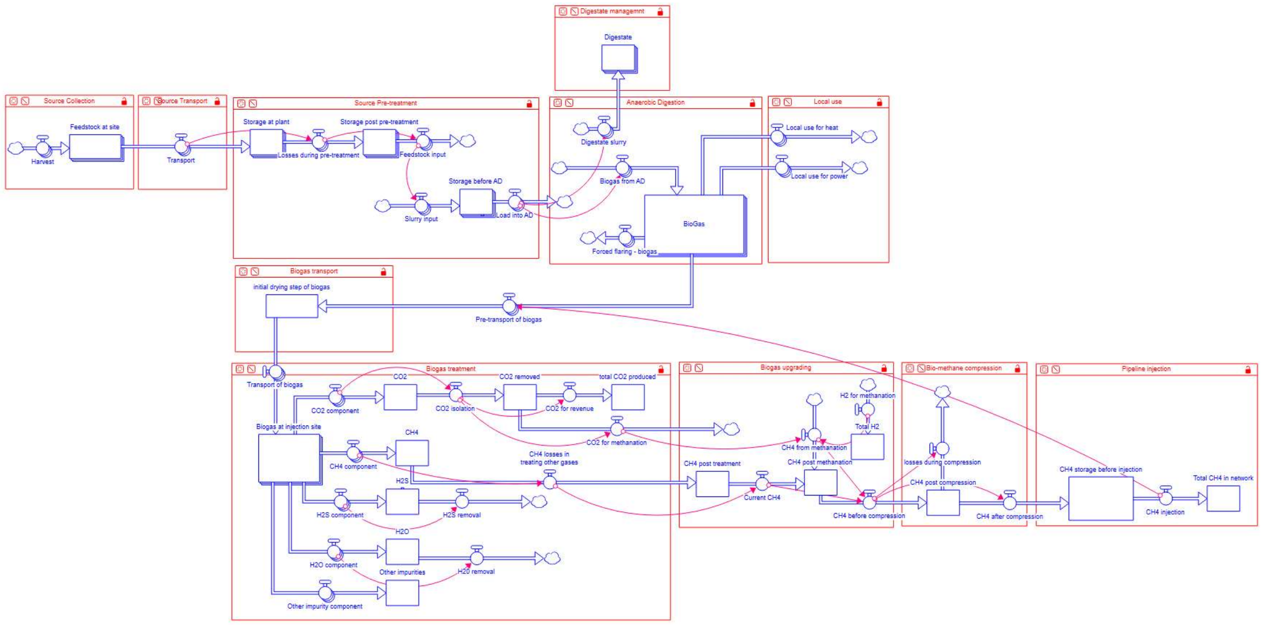

Figure 28: A detailed resolution of key processes and interactions in the production and grid injection of bio-methane

The following sections detail the underlying data and models used to estimate the sections of the biomethane production process. These sections are also aligned with the Final Framework Report from project RP1.2-03 (Culley, R. et al. 2021), which can be consulted for more general guidance around approaching a techno-economic assessment. In each section, the modelling approach is detailed, along with key sources of data in a table. Where a key parameter is case study dependent, it will be noted that this is user input from the interface in Section 4. In these instances, relevant data sources to assist with finding the correct value for the site are provided.

Throughout all these sub-sections, the techno-economic metrics from Section 2 (LCOE and carbon emissions) are calculated for each, and then totalled at the end of all the processes. The exception is part of the LCOE estimate, where there are both initial capital costs (CAPEX) and operational costs (OPEX) considered. The OPEX costs are still calculated in each section, however, for the CAPEX costing, a whole biomethane plant is estimated based on the biogas flows at the stage of anaerobic digestion, which includes the equipment required for pre-treatment, digestate management and biogas upgrading. The CAPEX for gas compression and storage are the only elements calculated independently as this will depend on the gas pipeline constraints more than the AD plant.

C.1 Source Collection

The first process is collection of feedstock, potentially across multiple sources. It is necessary to know the annual tonnes of feedstock available, and the moisture content of each feedstock, as this will affect the water requirements of anaerobic digestion. The feedstocks that are supported by this integrated assessment model, and their carbon to nitrogen ratios and moisture contents, are provided in Table 2.

Table 2: Feedstocks modelled in the project, including the carbon to nitrogen ratio and moisture content and yield estimate from Biogas opportunities for Australia, Figure 2

Feedstock Type	C/N Ratio	Moisture content	Yield (m3/T)

Wastewater	8	96%	4
Cereal Straw	52	9%	300
Vegetable Residue	40	88%	410
Sugarcane	140	44%	110
Manure	14.3	80%	25
Food Waste	21	58%	200
Hay Silage	42	27%	200
Poultry Bedding	15	22%	350
Winery Waste	55	53%	350
Fruit Residue	40	88%	350

There are no financial costs calculated as part of this stage, however, as part of the larger business case, the direct emissions that would result from a business as usual use of the feedstock (i.e. composing, landfill) are calculated. The key parameters for the source collection process, as well as sources for these parameters, are provided in Table 3.

Table 3: Key parameters and data sources for the source collection section of the integrated assessment model

Parameter	Value	Sources
Feedstock amount (tonnes/year)	User input (Section 3.2)	National map of bioenergy National organic waste profile (DAWE)
Moisture content (%)	10% (agricultural straw) – 98% (waste water) (see table 1)	Department of Agriculture, (GRDC 2018)
Emissions from landfill/decomposition (tCO_2e/tonne)	0.3 (agriculture waste) 2 (MSW/landfill)	Table 8.4 of IPCC report (Smith, D. Martino et al. 2007), Waste calculator: (Watch My Waste 2020)

C.2 Source Transport

This section of the tool is designed to estimate the requirements of transporting the feedstock streams to the anaerobic digestion plant. These requirements include both financial costs and carbon emissions (Section 2.1). In addition, there is an estimate of the number of truck drivers necessary to transport, but this is not currently reported on in the model interface (Section 4). The three metrics are calculated using different approaches. The calculation of overall cost is the most straight forward, as the cost of transport (in $/dry tonne) is provided by users through the interface. This number is taken as user input as the cost will vary significantly by region, and also by the distance required to cover. A default value of $40 is provided in the model, which is based on estimates from American biomass projects (Figure 29).

The number of truck drivers required relies on a calculation of the number of trips required to transport the trucks. The number of trips is calculated by taking the maximum allowable load for trucks in Australia (See Table 4) and dividing the feedstock amount by it. The carbon emissions and costs are more difficult to estimate, as they are provided based on both weight of truck, distance travelled, and also the percent empty (See Figure 30).

Table 4: Key parameters and data sources for the feedstock transport section of the integrated assessment model

Parameter	Value	Sources
Transport cost ($/tonne)	User input (Section 4)	Biotransformation of Agricultural Waste and By-Products (Poltronieri and D'Urso 2016)

		Headline economic value for waste and materials efficiency in Australia (CIE 2017)
Transport emissions (gCO_2e/tonne-km)	40-70	ECTA guidelines for measuring CO_2 emissions (McKinnon 2007)
Maximum transport load (tonne)	25	Harders Road weight limits (Harders 2020)

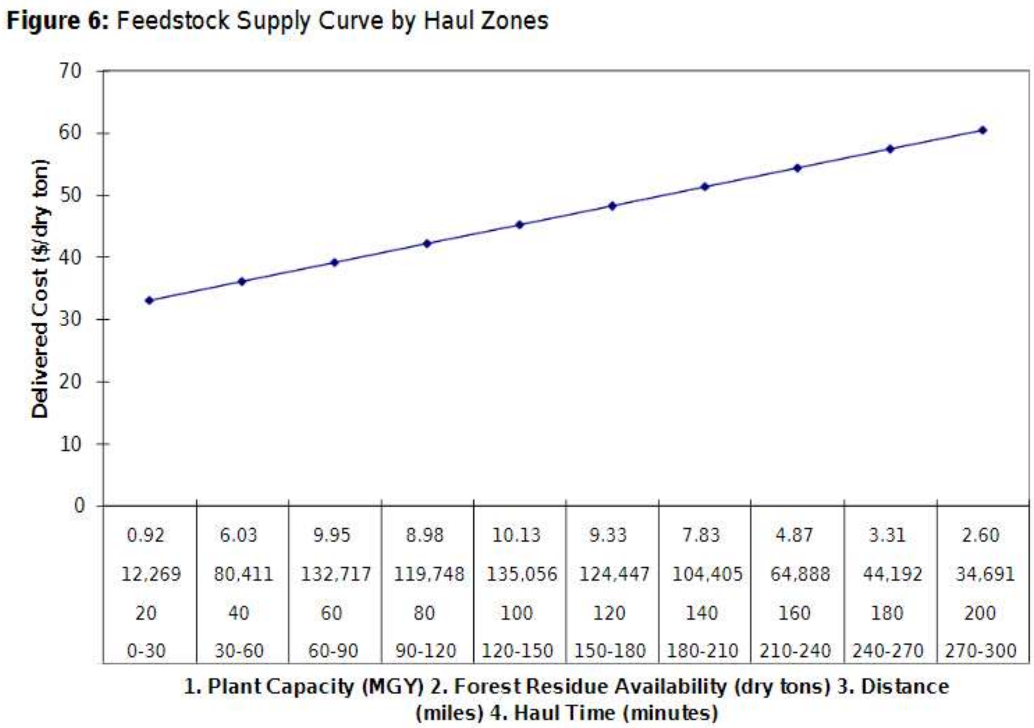

Figure 29: Transport costs for feedstock, presented in USD$/dry tonne.

Table 2
Carbon emission factors (gCO_2/tonne-km) for 40-44 tonne trucks with varying payloads and levels of empty running

Payload tonnes	% of truck-kms run empty										
	0%	5%	10%	15%	20%	25%	30%	35%	40%	45%	50%
10	81.0	84.7	88.8	93.4	98.5	104.4	111.1	118.8	127.8	138.4	151.1
11	74.8	78.2	81.9	86.1	90.8	96.1	102.1	109.1	117.3	127.0	138.6
12	69.7	72.8	76.2	80.0	84.3	89.2	94.7	101.1	108.6	117.5	128.1
13	65.4	68.2	71.4	74.9	78.9	83.4	88.5	94.4	101.3	109.5	119.3
14	61.7	64.4	67.3	70.6	74.2	78.4	83.2	88.7	95.1	102.7	111.8
15	58.6	61.0	63.8	66.8	70.3	74.2	78.6	83.7	89.7	96.8	105.3
16	55.9	58.2	60.7	63.6	66.8	70.5	74.6	79.5	85.1	91.7	99.7
17	53.5	55.7	58.1	60.8	63.8	67.2	71.2	75.7	81.0	87.2	94.7
18	51.4	53.5	55.8	58.3	61.2	64.4	68.1	72.4	77.4	83.3	90.4
19	49.6	51.5	53.7	56.1	58.8	61.9	65.4	69.5	74.2	79.8	86.5
20	48.0	49.8	51.9	54.2	56.8	59.7	63.0	66.9	71.4	76.7	83.0
21	46.6	48.3	50.3	52.5	54.9	57.7	60.9	64.5	68.8	73.9	80.0
22	45.3	47.0	48.8	50.9	53.3	55.9	59.0	62.5	66.5	71.4	77.2
23	44.2	45.8	47.6	49.6	51.8	54.3	57.2	60.6	64.5	69.1	74.7
24	43.2	44.7	46.4	48.3	50.5	52.9	55.7	58.9	62.7	67.1	72.4
25	42.3	43.8	45.4	47.3	49.3	51.7	54.3	57.4	61.0	65.2	70.3
26	41.5	42.9	44.5	46.3	48.3	50.5	53.1	56.0	59.5	63.6	68.5
27	40.8	42.2	43.7	45.4	47.3	49.5	52.0	54.8	58.1	62.1	66.8
28	40.2	41.5	43.0	44.6	46.5	48.6	51.0	53.7	56.9	60.7	65.3
29	39.7	41.0	42.4	44.0	45.7	47.8	50.1	52.7	55.8	59.5	63.9

Source: Alan McKinnon, based on data from Coyle, 2007

Figure 30: Carbon emissions from truck transport of feedstock

C.3 Source pre-treatment/storage

Before anaerobic digestion begins, it is necessary to form a slurry of feedstock and apply all required, and optional, pre-treatment strategies (Montgomery and Bochmann 2014), (Rabii, Aldin et al. 2019). Different pre-treatment strategies can have a significant impact on the yields of biogas but come at different costs. In this analysis, the data behind anaerobic digestion yields only assumes that the feedstock has been mixed and macerated, and so this is the only pre-treatment costed into the model. The CAPEX estimate scales as part of the AD plant estimate (Section C.4), and the OPEX is calculated by the power requirement for the maceration and conveyor belt for loading into the plant, as well as the water requirement for the feedstock slurry (Table 5).

Table 5: Key parameters and data sources for the feedstock pre-treatment section of the integrated assessment model

Parameter	Value	Sources
Water requirement (kL/tonne)	0-4	Chemical process modelling software (aspentech 2020)
Organic loading rate (tonnes/hour)	User input (Section 4.2)	-
Power requirement for pre-treatment (kWh/tonne)	5	Chemical process modelling software (aspentech 2020) A review of processes and energy requirements (Pilli, Pandey et al. 2020)
Cost of materials for pre-treatment ($/tonne)	Highly case study dependent	A review of processes and energy requirements (Pilli, Pandey et al. 2020) Biogas to bio-methane review, Table 3 (Ardolino, Cardamone et al. 2021)

C.4 Anaerobic digestion

There are two sets of calculations in this section of the model that have a significant impact on the overall techno-economic analysis: the yields from the anaerobic digestion reaction (Section C.4.1) and the CAPEX of the biomethane plant (Section C.4.2).

C.4.1 Anaerobic digestion yields

The calculation of the anerobic digestion reaction and yields is a critical component of the techno-economic viability assessment. Primarily, this section of the model determines the bio-methane potential (BMP) of the feedstock provided i.e. the GJ/tonne of the feedstock. In our model formulation, to be consistent with other publications, yield data is taken from the Biogas opportunities for Australia Report, and single digestion is assumed. To explore the effects of project operation on yield, this data is supported by a separate modelling approach using the chemical process modelling software aspen plus (thus making this an integrated assessment model). Each feedstock has been simulated using chemical processing software, both in isolation and also in pairwise combinations of the two, with 5 different mixing ratios. Simulations were run under two different temperature ranges: mesophilic and thermophilic. For each mixing ratio and temperature range, two different moisture contents were analysed: wet reactions (>98% moisture) and dry reactions (85% moisture). Note that the exception is wastewater, which was only modelled as a wet reaction due to its moisture content already being >98%. The effects of wet/dry and mesophilic/thermophilic have been applied to the tool. All data come from the modelling approach described in Robert, Culley et al. (2023). The following feedstock types are available for selection:

- Straw residue (both cereal and non-cereal straws)
- Hay and Silage
- Manure (pig, cattle, sheep)
- Poultry waste (a mix of bedding and manure)
- Winery waste
- Vegetable and/or fruit waste
- Organic municipal solid waste (an estimate of the food waste/green waste)
- Sugarcane Bagasse
- Wastewater Treatment plants

This model also estimates the composition of the biogas produced, and the solid and liquid fractions of the digestate. The composition of the gas is taken as 55% methane, 29% carbon dioxide, 10% water vapour, 2% hydrogen sulphide and 4% trace/inert gases.

C.4.2 CAPEX estimation

In the case study assessments from RP1.2-03, a "bottom-up" approach was used to calculate the CAPEX of a plant. This was a detailed process that relied on the Aspen Plus software and a database of costings for different machines, where a list of all the equipment for the designed plant was generated, and the costs for purchasing materials, and constructing/installing were totalled. This costing process takes a significant amount of time, and needs to start with a detailed chemical process model for each plant.

In an effort to generalise the costing approach to apply more broadly to a range of case studies, a more approximate method of costing is used. This is to estimate the cost of the plant based on its size, expressed in Nm^3/hour of biogas produced. This process is used as part of techno-economic assessments in industry reports and roadmaps for biomethane, where a relationship between size of plant and CAPEX has been established by studying all the existing biomethane projects in the world. CAPEX is estimated using existing cost curves from European biomethane projects (BioSURF report D3.4, 2016).

C.5 Digestate management/transport

For some biomethane projects there is potential value from the digestate, as it can be processed and sold as fertilizer, but this will also add production costs and potentially transport costs to consumers. If there are potential customers identified for the project, the revenue will offset the cost of digestate treatment and also some of the larger OPEX costs. A detailed techno-economic assessment of this supply chain is currently outside the scope of this model, however, the impact of the digestate can be explored through an estimate of the profit obtained from the feedstock.

This calculation is performed by considering the modelled solid digestate amount from Section C.4, and then the profit from digestate per tonne, which is a user input (Section 4). The key parameters, as well as sources for these parameters, are provided in Table 6.

Table 6: Key parameters and data sources for the digestate section of the integrated assessment model

Parameter	Value	Sources

Water content (%)	30-40	Chemical process modelling software (aspentech 2020) (Logan and Visvanathan 2019)
Digestate value ($/tonne)	User input (Section 2.2)	Price of fertilizer in Australia (Index Mundi 2020)
Available digestate (tonnes/hour)	Output from Section C.4 (roughly 10-20% of feedstock)	

C.6 Biogas transport

For some sites, the location of the anaerobic digestion plant may not be at the final point of injection into the pipeline, requiring the biogas to be transported. In this assessment, data has been obtained to cost two forms of transport. The first is by compressing the biogas and transporting by truck. In practice, the water vapour is first removed from the gas before compression. However, from a modelling standpoint, the water vapour removal is still costed in the upgrading process along with CO_2 and other impurities, as the volumes and therefore the total costs are the same (Section C.7). When modelling the transport of the gas via truck, many of the costing parameters are the same for the transport of feedstock (Section C.2), except now in Nm^3 of compressed gas (Table 7).

The second form of transport is via a gas pipeline. In this case the primary parameters are the distance required to transport, and then the cost of constructing a pipeline per km. This is treated as an additional capital cost for the project, not an operational cost.

Table 7: Key parameters and data sources for the biogas transport section of the integrated assessment model

Parameter	Value	Sources
Distance to upgrading/injection site (km)	User input (Section 3.2)	
Nm^3 capacity per trip (Nm^3)	4,500 m^3	(Hjort and Tamm 2012)
Cost of transport via trucks ($/$Nm^3$)	0.46	(Hjort and Tamm 2012)
Cost of pipeline ($/km)	400,000	(BiogasWorld 2021)

C.7 Biogas upgrading

Before injection into the pipeline, the biomethane needs to be isolated from the remaining gases. In this model formulation, this incudes CO_2, water vapour, hydrogen sulphide and other impurities. The removal of each of these components has a cost, dependent on the method used, the most significant of which is typically the removal of CO_2, given its larger volumes. There are also some losses of methane in each of these processes to consider.

Given the CO_2 removal is the most extensive, multiple options are provided for treatment; water scrubbing, and pressure swing absorption, and membrane separation. These two processes have differing operation requirements for both water and electricity (Figure 31). When removing water vapour, this is assumed to be done using a coolant, priced at $0.17/Tonne. The H_2S is assumed to be removed using chemical absorption, priced at $100/tonne.

	water scrubbing	amine scrubbing	membrane separation	physical scrubbing	pressure swing adsorption
Water consumption, m^3/m^3 of biogas	$22(10^{-5})$	$3(10^{-5})$	-	-	-
Electricity consumption, kWh/m^3 of biogas	0.265	0.1	0.22	0.25	0.23
Thermal energy consumption, kWh/m^3 of biogas	-	0.55	-	-	-

Figure 31: Different methods for removing CO_2 from biogas, and their requirements

Table 8: Key parameters and data sources for the biogas upgrading section of the integrated assessment model

Parameter	Value	Sources
Water required to remove CO_2 (kL/m^3)	0.00022	Biogas upgrader systems (Bauer, Persson et al. 2013) Biogas to bio-methane review, Table 3 (Ardolino, Cardamone et al. 2021)
Energy required to remove CO_2 (kWh/m^3)	0.23 or 0.265	Biogas upgrader systems (Bauer, Persson et al. 2013) Biogas to bio-methane review, Table 3 (Ardolino, Cardamone et al. 2021)
Oxide require to remove H_2S ($Tonne/m^3$)	0.002	Chemical process modelling software (aspentech 2020)
Coolant required to remove water (kL/m^3)	0.06	Chemical process modelling software (aspentech 2020)
Losses of methane (%)	2	Review of biogas upgrading technologies (Awe, Zhao et al. 2017)

C.8 Methanation

A simplified consideration of methanation is included as an end use for the residual CO_2 stream from the biogas treatment. This technology is still developing, and the consideration of methanation, as well as available hydrogen, is costed using estimates of how accessible this technology will be by 2030 (De Bucy, Lacroix et al. 2016). Other estimates of costs, including the maintenance costs, are shown in Figure 32.

The following assumptions are made in the methanation modelling:

- The reaction takes place with a 2:1 H_2:CO_2 reaction (Jaffar, Nahil et al. 2019), and yields 96% CH_4 from the CO_2 (De Bucy, Lacroix et al. 2016);
- The capital cost is €1000/kw (Figure 32), and the annual operating costs of methanation are 5% of the capital costs (De Bucy, Lacroix et al. 2016);
- The cost of hydrogen is 2.5 $/kg (Bruce, Temminghoff et al. 2018).

Source	Year	Power MW	Pressure [bar]	CAPEX € / kW SNG	OPEX % of CAPEX per year	ref
Gassner and Maréchal	2009	14,8	15	175		(7)
Outotec GmbH	2014	5	20	400		(7)
Outotec GmbH	2014	110	20	130		(7)
Lehner et al. (three reports)	2014			300-500	8%	(7)
Ausfelder et al. (2015)	2050			600		(7)
E&E Consultant (2014)	2014			1500		(7)
E&E Consultant (2014)	2030			500		(7)
Ueckerdt et al.	2013			1000		(7)
Grahn & Jannasch	2018			600	4%	(9)
enea consulting	2016		10	1500	5-10%	(10)
enea consulting	2030		10	1000	5-10%	(10)
enea consulting	2050		10	700	5-10%	(10)
Danish Energy Agency	2020	3,3		910	6-8%	(12)
Danish Energy Agency	2030	8,3		760	6-8%	(12)
Danish Energy Agency	2050	23,1		450	6-8%	(12)
Haldor Topsøe	2017	25		670	3%	(1)

Figure 32: A comparison of CAPEX and OPEX estimates for methanation, including year of pricing estimate

C.9 Biomethane compression

Once the bio-methane has been isolated and has a specification suitable for injection into the pipeline, it is compressed to the pressure required. This pressure requirement is highly case study dependent, and so is defined by users through the model interface. The compression for higher injection pressures is assumed to take place in stages to control for temperature of the gas, requiring separate compression machines. There is an option for selecting a transmission line or a distribution line, which changes the CAPEX estimate between $20M and $3M.

Table 9: Key parameters and data sources for the biomethane compression section of the integrated assessment model

Parameter	Value	Sources
Injection pressure	User input (Section 4.2)	
Compression energy requirement (kWh/m^3)	0.22	Chemical process modelling software (aspentech 2020)
Biomethane lost during compression (%)	1	

C.10 Biomethane grid injection

Provided there is sufficient demand for gas, it is injected into the pipeline and the quantity is counted in both Nm^3/h and GJ/h. Otherwise, the gas is flared. The carbon emissions avoided due to displacing gas in the pipeline are calculated using the values from the Australian National Greenhouse Accounts Factors (Table 10).

Table 10: Key parameters and data sources for the grid injection section of the integrated assessment model

Parameter	Value	Sources
Heat value of biomethane	0.038	

Emissions avoided due to displacement (kgCO2e/GJ)	51.53	Australian National Greenhouse Accounts Factors

C.11 Metric calculations and recurring costs

When simulating all the above processes, the underlying system dynamics model simulates the production of biomethane at the hourly timestep, for the period of a year. It will then forecast the outputs of the plant for the duration of the project life, in order to estimate the net present value, and the total magnitude of net carbon emissions. Before forecasting, it totals the CAPEX, OPEX, and Revenue streams, and the direct/indirect carbon emissions, and carbon emissions avoided. Where the costs and emissions were specific to a process, the method of calculation was stated. However, there are a few key mechanics behind cost and carbon emissions that occur throughout the whole process, which are estimated at the end of the simulation. This primarily involves the utilities (i.e. power, gas, water) used throughout.

The power and gas needs of the plant are tallied in each process, where the cost of supplying the electricity is determined based on the user input (Section 4.2). When this electricity is drawn from the grid, there are also carbon emissions to consider based on the method of producing electricity (Figure 33). Due to the differing levels of renewable energy penetration across Australia, the emissions from using electricity from the grid differ. Likewise, the emissions from using or displacing natural gas in the pipeline also differ. These are all estimated using the Australian Nation Greenhouse Accounts Factors[3].

At the final timestep of the simulation, any policy offsets are also calculated. Currently, this includes a renewable heat incentive, and a carbon credit. The carbon credit uses the net emissions avoided to estimate a revenue stream based on user input (Section 4.2), and the renewable heat incentive uses the total biomethane injected (in GJ) along with a user input value in $/GJ to calculate the offset. These revenue streams are then subtracted from the annual operational costs before calculating the NPV and the LCOE.

[3] https://www.dcceew.gov.au/sites/default/files/documents/national-greenhouse-accounts-factors-2022.pdf

Table 1 Indirect (Scope 2 and Scope 3) emissions from consumption of purchased electricity from a grid

State, Territory or grid description	Scope 2 Emission Factors		Scope 3 Emission Factors	
	kg CO_2-e/kWh	kg CO_2-e/GJ	kg CO_2-e/kWh	kg CO_2-e/GJ
New South Wales and Australian Capital Territory	0.73	202	0.06	15
Victoria	0.85	238	0.07	20
Queensland	0.73	202	0.15	41
South Australia	0.25	72	0.08	23
Western Australia - South West Interconnected System (SWIS)	0.51	164	0.04	12
Tasmania	0.17	47	0.01	3
Northern territory - Darwin Katherine Interconnected System (DKIS)	0.54	152	0.07	19
Western Australia - North Western Interconnected System (NWIS)	0.58	160	NE	NE
National	0.68	189	0.09	25

Sources: Primary data sources comprise National Greenhouse and Energy Reporting (Measurement) Determination 2008 (Schedule 1), Australian Energy Statistics, Clean Energy Regulator, and AEMO data and Department of Climate Change, Energy, the Environment and Water.

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Figure 33: Carbon costs in drawing energy from the grid

APPENDIX D

A full list of the sensitivity of LCOE and net carbon saved to the factors explored in this assessment

Variable	Parameter		Change in LCOE		Change in Carbon saved	
Variables	min	max	min	max	min	max
Feedstock amount	5000	300000	36.3	-3.2	-51400	107900
Emissions avoided from feedstock	0	2	0	0	-50010	149900
Feedstock availability	8.3	100	55.6	0	100	0
Transport cost	30	70	-1.1	3.5	0	0
Distance to plant	0	100	-0.5	1.8	100	-500
Water requirement	0	5	-0.3	1.4	0	0
Biogas content	0.5	0.7	3.9	-2.7	-2000	2000
Energy density	50	600	60.8	-3.5	-6600	3800
Digestate recovered	0	80	-0.1	0.1	-800	800
Losses of biogas at plant	0	4	-0.4	0.4	7600	-7600
Energy of CO2 removal	0.1	0.265	-0.3	0.1	800	-300
Water for CO2 removal	0	0.00003	0	0	0	0
Losses from upgrading	0	3	-0.4	0.2	7700	-3900
Cost of compression	0	6000000	-0.5	0.5	0	0
Distance to network	0	50	0	3.6	0	0
Portion of biomethane injected	0.5	1	21	0	-24500	0
Digestate profit	-100	150	4.6	-6.9	0	0
Gate fee	0	40	0	-4.6	0	0
Carbon profit	0	200	0	-2.1	0	0
GGSS	0	15	0	-15	0	0
Renewable gas guarantee of origin (RGGOs)	0	40	0	-11.11	0	0

Feed in tariff	0	7.1	0	-7.1	0	0
Displacement ACCU	0	60	0	-2.3	0	0
Conversion ACCU	0	60	0	-1.9	0	0
Direct grant funding	0	12,000,000	0	-2.1	0	0
Transport emissions	0.04	0.07	0	0	0	0
Emissions from grid power	0.00017	0.00085	0	0	7100	-2400
Wages	35	50	-0.1	0.2	0	0
Cost of electricity	0.15	0.35	-0.8	2.4	0	0
Cost of water	2	3.035	-0.1	0	0	0
Maintenance costs	2	5	-0.7	1.3	0	0

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