B5 Research Project

Biogas from agricultural waste - A techno-economic evaluation

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Industry Report

Biogas from agricultural waste - A techno-economic evaluation

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Citations

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Project partners

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Acknowledgement of Country

The authors of this report would like to respectfully acknowledge the Traditional Owners of the ancestral lands throughout Australia and their connection to land, sea and community. We recognise their continuing connection to the land, waters and culture and pay our respects to them, their cultures and to their Elders past, present, and emerging.

What is RACE for 2030?

RACE for 2030 CRC is a 10-year cooperative research centre with AUD350 million of resources to fund research towards a reliable, affordable, and clean energy future. https://www.racefor2030.com.au

Executive summary

The purpose of the project was to assess the techno-economic feasibility of biogas production and use from sugar mills such as Mossman Sugar Mill. The study report was prepared by Griffith University, with inputs from Singh Farming and industry reference group (IRG) members of RACE for 2030. The report is based on lab-scale experimental data and modelling carried out at Griffith University.

Mono-digestion of sugarcane bagasse, trash, mill mud, chicken manure, food waste and banana waste were performed in the laboratory. Methane yields obtained from sugarcane mill mud were higher than those obtained from sugarcane bagasse or trash. To improve the methane yields from high-carbon-containing sugarcane bagasse, codigestion of the sugarcane bagasse and mill mud with nitrogen-rich chicken manure was performed. Best methane yields were obtained when sugarcane bagasse and mill mud were codigested with chicken manure and food waste followed by codigestion of sugarcane bagasse and mill mud with food waste or with chicken manure. Codigestion of sugarcane bagasse with mill mud alone produced the lowest methane yields. The methane yields obtained from the laboratory codigestion studies were used to design and conduct a techno-economic evaluation of a full-scale biogas plant. The biogas plant is planned to be located adjacent to the Mossman Sugar Mill. This feasibility study shows that a 2.2 MW biogas plant can generate approximately 9.35 million Nm^3 of biogas per year through codigestion of 20,000 tonnes per year of sugarcane bagasse and 30,000 tonnes per year of mill mud with 5,000 tonnes per year of locally available chicken manure. The biogas plant (3 × 6,000 m^3) will be operated at an organic loading rate of 3.3 kg VS/m^3/day and hydraulic retention time (HRT) of 35 days under mesophilic conditions (37°C). However, the minimum plant capacity should be 6.6 MW to make it economically viable.

Three different scenarios were evaluated for the economic viability of the project. The produced biogas will be used for electricity and heat generation in a combined heat and power (CHP) plant (Scenario 1), upgraded to compressed biomethane (BioCNG) (Scenario 2) or upgraded to biomethane for grid injection (BioRNG) (Scenario 3). In Scenarios 2 and 3, a part of the biogas will be used for CHP to meet the plant energy demands, with the remaining biogas updated to biomethane. The carbon dioxide from the biogas upgrading process will be recovered and liquefied for sale ($BioCO_2$). The nutrient-rich digestate from the biogas plant will be further processed into a solid fraction and a liquid fraction. The solid fraction will be sold as fertiliser while the liquid fraction will be recycled as process water. Mass and energy balance were also analysed along with the greenhouse gas (GHG) emissions avoided by replacement of fossil fuels and replacement of inorganic nitrogen fertiliser and its application.

Total investment required for the project varied and depends on biogas usage. The total investment required was $24–25 million for Scenarios 2 or 3 and $20.4 million for Scenario 1 (see following table). The estimated revenue per annum with the inclusion of Australian Carbon Credit Units (ACCUs) and green certificates ranged from ~$3.4 million in Scenario 1 to $4.3 million in Scenario 3 and $5.3 million in Scenario 2. Although ACCUs are not currently available in Australia for such projects, there is scope for ACCUs to be implemented for future selected bioenergy projects, according to a report by The Office of the Minister of the Environment (2017)[1], which states that offset projects carried out in accordance with a methodology determined and approved by the Clean Energy Regulator (CER) can generate ACCUs. As the ACCUs represent the project's emissions reductions, the project proponents can receive funding by entering their projects into a CER-run competitive auction. The government will enter into contracts with successful proposers that will guarantee the price and payment for future emission reductions.

Under Scenario 1, approximately 48% of the revenue/savings would result from the sale of electricity to grid, with the remaining revenue coming from sale of solid digestate. Sale of BioCNG and $BioCO_2$ in Scenario 2

[1] Office of the Minister of the Environment (2017). Carbon Credits (Carbon Farming Initiative – Plantation Forestry) Methodology Determination 2017.

accounted for 60% of total revenue. Internalising the environmental benefits of avoided GHG emissions through inclusion of ACCUs and green certificates, the return on investment (ROI) for the studied scenarios are 4.8%, 10.5% and 6.7% for Scenarios 1, 2 and 3, respectively. Conversely, ROIs without ACCUs and green certificates would be −1.9 to 4.2%. Thus, AD projects are less economically viable without government support in investment, ACCUs and green certificates.

Overview of financial analyses of a 2.2 MW biogas plant.

Project parameters	Scenario 1	Scenario 2	Scenario 3
	($/year)	($/year)	($/year)
CapEx			
Total CapEx including contingency	17,315,495	21,147,455	20,006,575
Investment required (including EPCM)	20,432,284	24,953,997	23,607,759
OpEx			
Total OpEx	2,405,240	2,711,796	2,731,410
Revenue			
Total revenue	3,384,062	5,357,701	4,339,167
ROI (%)	4.8	10.5	6.7
IRR (%)	1.1	9.2	4.2
Payback period (years)	21	10	15
NPV ($)	−10,579,827	-1,303,418	−8,559,099

Technical, regulatory and economical barriers need to be removed and/or addressed to allow AD projects to compete with other comparable technologies in the renewable energy and carbon markets in Australia. Currently, agriculture resources are not being utilised through lack of incentives to farmers. For agriculture to play its part in decarbonising the economy, key barriers need to be removed. Potential ways to overcome these barriers include:

1. Inclusion of agriculture in future Emission Reduction Fund (ERF) methods to allow ACCUs to be created for an agriculturally based AD project.
2. Inclusion of biomethane in the hydrogen Guarantee of Origin scheme to allow biomethane to be certified as a renewable feedstock for hydrogen production.
3. Amend the National Greenhouse and Energy Reporting (NGER) scheme so that BioCNG or BioRNG delivered to an end user will reduce their reportable emissions under Commonwealth government programs and policies (CERT, NGERS and Safeguard Mechanism).

With the removal of barriers, costs will reduce, and farmers will be encouraged to pool feedstocks and invest in a centralised biogas plants of large-scale AD projects. To achieve the scale of production, a group of 15–20 farms could form a cooperative society and build a large-scale centralised biogas plant, similar to the Danish centralised biogas plant model. Sensitivity analyses also showed that AD projects are very sensitive to feedstocks gate fees, feed-in tariffs and plant capacity. Scale of production, in particular, had a profound influence on ROI, with a biogas plant size of 6.6 MW significantly reducing costs and making AD among the most competitive technologies in the renewable and carbon markets, with ROIs of 27–33%. Thus, onsite production and/or use of renewable energy will enable to achieve sustainable management of sugar mill wastes and help to decarbonise the agricultural sector.

Contents

List of abbreviations

ACCU	Australian Carbon Credit Unit
AD	anaerobic digestion
BAU	business as usual
BioCNG	biomethane compressed natural gas
$BioCO_2$	carbon dioxide from biogas upgrading process
BioRNG	biomethane renewable natural gas
BMP	biochemical methane potential
CapEx	capital expenditure
CER	Clean Energy Regulator
CERT	Corporate Emissions Reduction Transparency
CHP	combined heat and power plant (or cogeneration)
CO_2-e	carbon dioxide equivalence
CSTR	continuously stirred tank reactor
EBITDA	earnings before interest, tax, depreciation and amortisation
EPCM	engineering, procurement and construction management
ERF	Emission Reduction Fund
FM	fresh matter
FOFO	food organics and garden organics
GHG	greenhouse gas
HRT	hydraulic retention time
IRG	industry reference group
IRR	internal rate of return
K	potassium
LEL	lower explosive limit
MW	megawatt
N	nitrogen
Nm^3	cubic metres, normalised to STP
NGER	National Greenhouse and Energy Reporting
NPV	net present value
O&M	operation and maintenance costs
OLR	organic loading rate
OpEx	operating expenditure
P	phosphorus
PBP	payback period
ROI	return on investment
STP	standard temperature and pressure (0°C, 1 atm)
TKN	total Kjeldahl nitrogen
TS	total solids
VS	volatile solids

1 Technical feasibility of biogas production

1.1 Introduction to feasibility study

Singh Farming and Griffith University have identified surplus sugarcane bagasse (20,000 t/a) and mill mud (30,000 t/a) as potential feedstocks for anaerobic digestion (AD) with locally sourced chicken manure (5,000 t/a) to generate biogas (i.e., codigestion). In addition to biogas, the AD process would also produce a nutrient-rich digestate. The digestate can be pasteurised and separated into solid and liquid fractions. The solid fraction would be sold as a soil conditioner/organic fertiliser while the liquid fraction would be recycled as process water in the AD plant.

To assess the feasibility of the proposed project, different scenarios were designed with an aim to evaluate the possible market opportunities for biogas uses and the overall return on investment (ROI) it generates. Scenario development is important to determine the outcomes of project development in a context that is relevant for stakeholders. Further, the studied scenarios will also help in the process of decision-making. Based on the biogas usage, three different scenarios were considered in this feasibility study and are presented in Table 1.

- **Scenario 1: CHP**—Biogas is used for electricity and heat generation in a combined heat and power (CHP) plant.
- **Scenario 2: CHP + BioCNG**—A portion of biogas is used for CHP to generate electricity and heat to meet the parasitic demand of the biogas plant and the remaining biogas is upgraded and compressed (BioCNG) for vehicle fuel or distribution via virtual pipeline (road transport).
- **Scenario 3: CHP+ BioRNG**—Similar to Scenario 2 but the biogas is upgraded to renewable natural gas (BioRNG) for grid injection.

Under both Scenarios 2 and 3, the carbon dioxide (CO_2) will be recovered and liquified to be sold as food grade BioCO_2.

Table 1. Project parameters for the three studied biogas use scenarios.

Project parameters	Scenario 1	Scenario 2	Scenario 3
Biogas use	Electricity generation, grid supply CHP	30% electricity generation, 70% biogas upgrading CHP + BioCNG	30% electricity generation, 70% biogas upgrading CHP + BioRNG
Biogas plant outputs	Electricity Digestate Heat	Electricity BioCNG BioCO_2 Digestate Heat	Electricity BioRNG BioCO_2 Digestate Heat
Grid electricity required for biogas plant	No	No	No

1.2 Drivers for feasibility study

The cost of sugarcane crop production in Queensland is increasing every year. Of the total production costs, water and pumping accounts for 15% each while diesel fuel accounts for 10%. Diesel consumption is estimated at 3 L/t cane. The high costs of water, electricity and diesel are severely limiting crop yields and farm profitability since farmers are unable to afford sufficient water at critical crop growth stages. A highly prospective opportunity to reduce energy costs is to produce biogas using sugar industry wastes, given their high energy content. By generating electricity onsite, we can reduce the retail and transmission costs by up to 50% of total electricity costs. The biogas can also be upgraded to BioCNG to replace grid-supplied electricity and diesel used for irrigation, farming, and transport.

Currently, sugar industry wastes are used for on-site energy generation in boilers, which were designed as incinerators for burning bagasse rather than recovering full energy potential of biomass. Mill mud is currently spread on farms as soil conditioner. Biogas can play an important role by providing an opportunity to meet our renewable energy targets and decarbonise our economy, as well as provide a holistic solution for the sugar industry and other livestock farms and municipalities in managing their wastes. The national biogas industry is likely to expand, as there is significant potential for growth in feedstock, coupled with rising electricity prices and landfill levies.

This project will repurpose sugar industry wastes to reduce operating costs for Australian sugar farms and help them in transitioning to renewable energy.

1.3 Methodology for feasibility study

1.3.1 Plant location

The plant will be located at Mossman Sugar Mill, Mossman, Queensland.

1.3.2 Biogas plant design calculations and assumptions

Techno-economic evaluation of biogas production from the studied feedstocks was performed as per the designed total electrical power output of 2.2 MW. Based on the best methane yields obtained in the biochemical methane potential (BMP) study, codigestion of sugarcane bagasse and mill mud with chicken manure was selected. The biogas plant will be operated all year round with some days allocated for repair and maintenance. The plant will operate 24/7 and is expected to be equipped with sufficient instrumentation and telemetry to allow for remote access and control of the plant. An estimated operational period of 8,300 h/year was considered.

The plant will be operated as follows:

- waste streams delivered to biogas plant 7 days/week during sugarcane harvesting and processing season
- biogas generation 24/7, year-round with 95% plant availability
- BioCNG/RNG/electricity production 24/7, year-round
- power demand (where applicable) 24/7, year-round
- liquid digestate discharge 24/7, year-round
- solid digestate offtake 4–5 days/week, year-round.

Table 2 shows the feedstock quantities (t/d), chemical composition and methane potentials used for the design calculations. Sugarcane bagasse and mill mud will be collected from Mossman Sugar Mill while chicken manure will be procured from Mareeba. The road transport distance is estimated to be 75 km. The methane yields used in the study were normalised to standard temperature and pressure (STP) conditions (0°C, 1 atm).

Table 2. Feedstock amounts along with their chemical composition and methane yields used for design calculations of farm-scale biogas plant.

Feedstocks	Biomass	TS[1]	VS[1]	Methane yields	Mass	Energy
	(t/d)	(% w/w)[2]	(%TS)	(Nm^3/kg VS_{added})[3]	(% w/w)	(%)
Solid co-substrates						
Sugarcane bagasse	55	48.87	90	0.306	12.5	51.4
Sugarcane mill mud	82	22.66	69	0.365	18.7	32.7
Chicken manure	14	74.31	83	0.271	3.1	15.9
Subtotals	**151**				**34.4**	**100**
Water/liquid digestate (kL/d)	265				65.6	–
Total mass	**416**					

Notes

1 TS – total solids, VS – volatile solids

2 w/w: wet weight

3 Methane yields (Nm^3/kg VS_{added}) are calculated after being normalised to standard temperature and pressure

1.4 Biogas plant design

The biogas plant concept and process flowchart for CHP generation (Scenario 1) and for CHP + BioCNG with additional $BioCO_2$ production (Scenario 2) are presented in Figure 1 and Figure 2, respectively. The process flowchart for Scenario 3 is not presented as it is similar to Scenario 2, with only minor changes in biomethane use equipment. Both bagasse (55 t/d) and mill mud (82 t/d) generated during the cane crushing season (June to December) will be used as feedstock. For off-season supply, biomass produced during the on-season will be ensilaged and stored as silage in concrete bunker silos. Two concrete bunker silos (10 m × 4.5 m × 2.5 m) were considered for the ensilation process. Lactic acid bacteria at the rate of 4–5% on fresh weight basis will be used. Possible storage losses were not considered in this study. On the other hand, chicken manure (14 t/d) is procured from poultry farms in Mareeba.

The feeding technology consists of maceration coupled with an augur feeding system and feed buffer tank. Feedstocks are macerated, mixed, homogenised and fed into the buffer tank. In the buffer tank, chicken manure is added along with process water (265 kL/d) and liquid fraction of the digestate, to adjust the solids content to <8%. The feed buffer tank (2,900 m^3) was designed to prepare feed for five working days (Monday through Friday). Feed rates were designed so that the feedstocks will be consumed evenly throughout the year. The prepared feed is then fed to the biogas reactors (Figure 1 and Figure 2).

Three semi-continuously stirred tank reactor (CSTR) systems (3 × 6,000 m^3) were designed to enable the implementation of the proposed codigestion system in a full-scale plant. CSTR technology is widely applied in the European biogas plants for a range of residues including energy crops and livestock manure AD (Janke et al., 2016)[2]. The reactors have mechanical agitators to mix the reactor contents. The rectors will be operated at an organic loading rate (OLR) of 3.3 kg VS/m^3/d, hydraulic retention time (HRT) of 35 d and process temperature of 37°C. The well-insulated upright galvanised steel CSTR reactor has sufficient headspace for biogas to evolve and flow to a post-storage tank.

The biogas and digestate produced from the three CSTR reactors are stored in the post-storage tank (10,000 m^3). Prior to solid–liquid separation of digestate, the whole digestate is sent to pasteurisation (2 × 6.0 m^3) and carried at 70°C for 1 h to kill the zoonotic pathogens in the digestate. The pasteurised material

[2] Janke, L., Leite, A., Batista, K. (2016). Enhancing biogas production from vinasse in sugarcane biorefineries: Effects of urea and trace elements supplementation on process performance and stability.

is then separated into solid and liquid fractions by using a decanter centrifuge (48.3 m^3/h). The solid fraction is sold as soil conditioner while the liquid fraction is returned as process water to dilute the incoming feedstock.

The biogas train consists of a biogas blower, desulphurisation unit and a flare. In Scenario 1, desulphurised biogas is fed to the CHP plant (2 × 1,200 kW) by a biogas blower (1,060 m^3/h) to produce heat and electricity (Figure 1).

Two stationary internal combustion engines (electrical output of 899–1,500 kW and thermal output of 95–1,812 kW) with an electrical conversion efficiency of 0.424 and thermal conversion of 0.426 were used. After meeting the parasitic electricity needs, the surplus electricity is fed to the grid. Heat as hot water from the CHP plant is used internally for heating the reactors.

In Scenario 2, approximately 8,703 m^3/d of biogas (33% of total production) is fed to the CHP plant (850 kW) to produce heat and electricity to meet the parasitic demands of the biogas plant. The remaining biogas (17,671 m^3/d) is fed to a membrane biogas upgrading unit (700 m^3/h raw biogas) coupled with CO_2 recovery and liquefaction plant (350 m^3/h) to produce BioCNG and bioCO_2, respectively. The PurePac Medium biogas upgrading system (400–1,000 Nm^3/h raw biogas) and CO_2 recovery system, manufactured by Bright Biomethane (the Netherlands) was considered. A methane yield of 99.5% is guaranteed in this highly efficient membrane upgrading technology. A 2% BioCH_4 slip was considered during biogas upgrading. This reflects the worst-case scenario within the range (1–2%) usually observed in upgrading technologies (Muñoz *et al.*, 2015)[3]. In case of emergency, biogas can be flared on site by using the biogas flare (539.5 m^3/h).

3 Muñoz, R., Meier, L., Diaz, I., Jeison, D. (2015). A review on the state-of-the-art of physical/chemical and biological technologies for biogas upgrading. Rev Environ Sci Bio/Technol. 14:727–759.

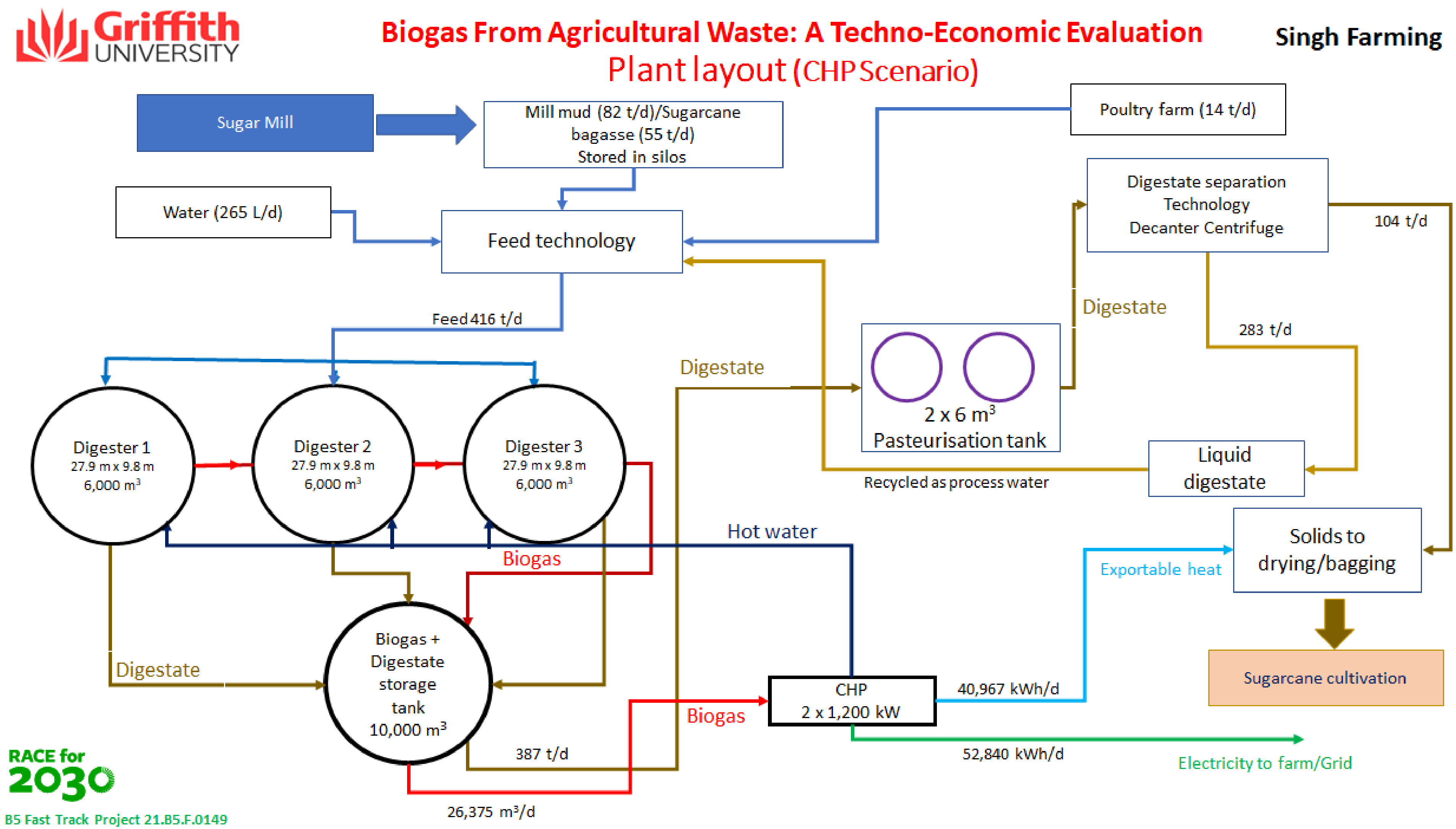

Figure 1. Process flowchart of the anaerobic codigestion of sugar mill wastes with chicken manure (CM) for combined heat and power generation (Scenario 1).

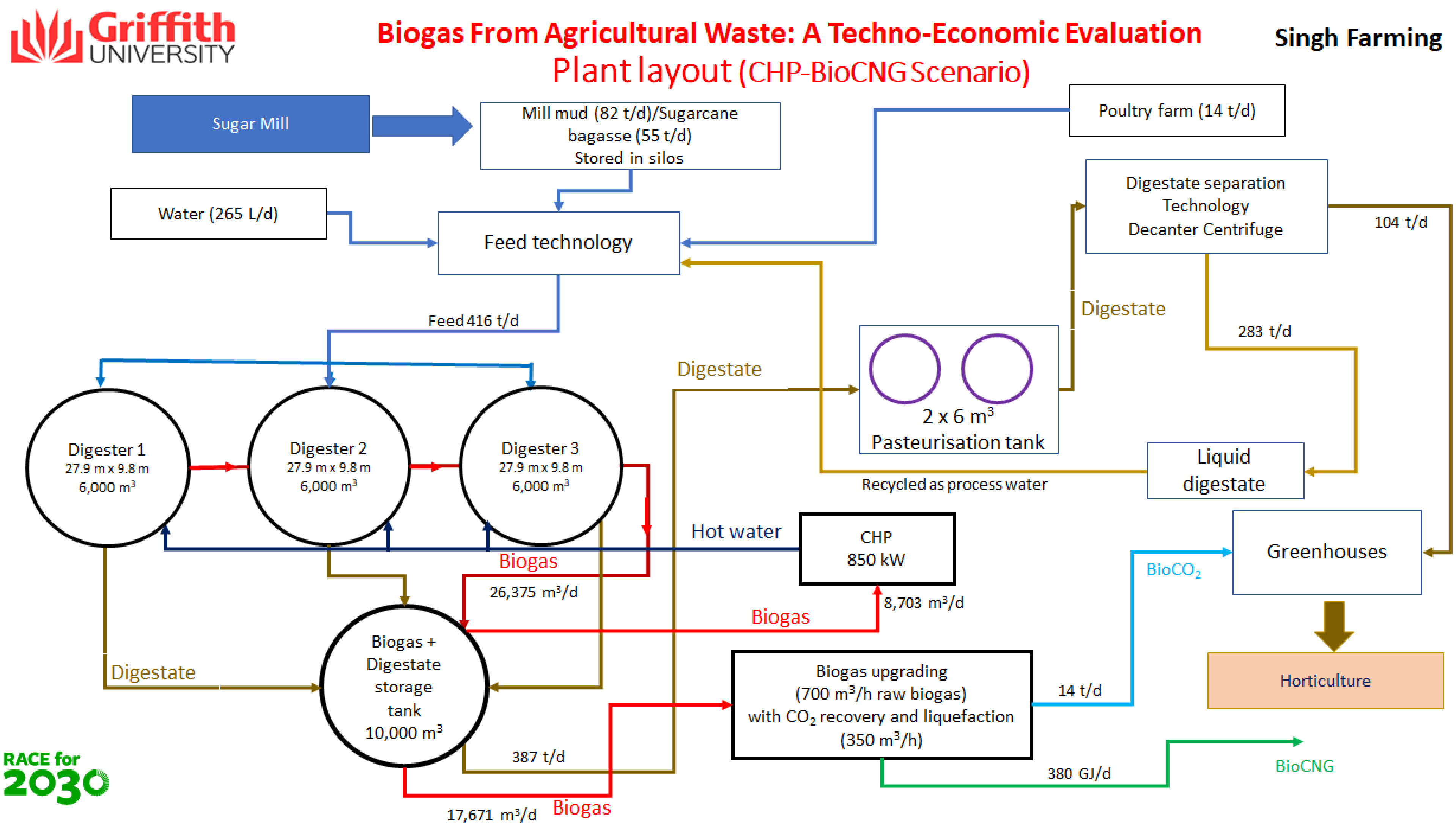

Figure 2. Process flowchart of the anaerobic codigestion of sugar mill wastes with CM for biogas upgrading to produce BioCNG and BioCO$_2$ (Scenario 2). Note that as electricity from the CHP plant is consumed in the plant, it is not shown in this diagram.

1.5 Mass balance

Table 3 details the mass balance for the studied scenarios. For all scenarios, anaerobic codigestion of 151 t/d of the studied feedstock and 265 kL of water will produce 26,376 m³/d of biogas (30 t/d) and 386 t/d of digestate. Separation of the digestate into solid and liquid fractions by using a decanter centrifuge resulted in 104 t/d of solid fraction and 283 kL/d of liquid fraction. The solid fraction accounted for 27.16% w/w of the total digestate and had a solids content of 30% (Table 4). The liquid fraction had a solids content of 1.2%.

Table 3. Mass and energy balance of anaerobic codigestion of sugar mill by-products with chicken manure.

Mass balance	Units	Scenario 1 CHP + electricity	Scenario 2 CHP + BioCNG	Scenario 3 CHP + BioRNG
Total feedstock treated	t/d	151	151	151
Additional water/wastewater	kL/d	265	265	265
Biogas produced	m³/d	26,376	26,376	26,376
Methane produced	m³/d	14,773	14,773	14,773
Energy in methane produced	GJ/d	567	567	567
Electricity generated	kWh/d	61,456	19,797	19,797
	GJ/d	222	71	71
Heat generated	kWh/d	58,304	19,276	19,276
	GJ/d	210	70	70
Biomethane produced	GJ/d	–	380	380
Carbon dioxide produced	t/d	–	14	14
Parasitic demand—electrical	kWh/d	8,615	15,191	14,664
Parasitic demand—heat	kWh/d	17,337	17,337	17,337
Import of electricity	kWh/d	–	–	–
Import of heat (natural gas)	kWh/d	–	–	–
Exportable electricity—grid	kWh/d	52,840	4,605	5,133
Exportable heat	kWh/d	40,967	1,938	1,938
Digestate production	t/d	387	387	387
Solid digestate	t/d	104	104	104
Liquid digestate	kL/d	283	283	283

1.6 Energy balance

Table 3 shows the energy balance for the studied scenarios. For all scenarios, a daily biogas production of 26,376 m³/d was obtained from 151 t/d of feed. In Scenario 1, use of the produced biogas for heat and electricity generation in CHP resulted in 61,456 kWh/d of electricity and 58,304 kWh/d of heat. Considering the energetic performance in Scenario 1, the installed capacity of the biogas plant is 2.2 MW. For Scenario 2, use of biogas (33% of total production) for heat and electricity cogeneration in a smaller size CHP plant (1 × 850 kW) produced 19,797 kWh/d of electricity and 19,276 kWh/d of heat. The remaining biogas, when used for biogas upgrading with integrated CO_2 recovery and liquefaction, can produce 380 GJ/d of BioCNG and 14 t/d of food-grade $BioCO_2$. The produced BioCNG can be used to replace fossil fuel in vehicles (Scenario 2) or injected into the natural gas grid (Scenario 3), depending on the production level and the distance to the natural gas grid. In contrast to electricity generation in Scenario 1, where heat losses usually account for over 50% of the available 'raw energy' (i.e., the installed capacity of the biogas plant), the energy potential of BioCNG production could reach values as high as 98% owing to the much lower energy loss levels (2% in this case).

The parasitic energy demand for biogas plants in the studied scenarios varied and was dependent on the process configuration and the plant equipment used. In Scenario 1, parasitic energy demand was 8,615 kWh/d of electricity and 17,337 kWh/d of heat. This energy demand was supplied by the produced heat and electricity from onsite CHP plant. Thus, import of heat (natural gas) and electricity (grid electricity) was not required. For Scenario 2 and 3, the parasitic energy demands were relatively high (15,191 kWh/d of electricity). This high energy demand is attributed to the energy requirements of the BioCNG (4,560 kWh/d electrical) and for liquefaction of BioCO_2 (2,016 kWh/d electrical). The electrical energy requirement for biogas cleaning and upgrading with compression was 0.3 kWh/m^3 raw biogas (Scenario 2) and without compression was 0.22 kWh/m^3 raw biogas (Scenario 3). The corresponding electrical energy requirement for CO_2 recovery and BioCO_2 liquefaction was 0.24 kWh/m^3 CO_2 (Scenarios 2 and 3). The surplus electricity of 52,840 kWh/d is available for grid injection in Scenario 1. The corresponding values in Scenarios 2 and 3 were 4,605 and 5,133 kWh/d, respectively.

Apart from economic and environmental implications, BioRNG production largely outperforms the energetic exploitation of biogas compared to electricity generation on a conservative basis. Total energy content in the biomethane in Scenario 2 or 3 was 380 GJ/d (Table 3). This considerable amount of surplus biomethane could be also used to produce electricity, characterising a highly flexible AD plant. In the current sugar industry scenario, bagasse can be used in boilers for production of baseload power during the cane crushing season only. With AD of bagasse, we can store the biogas to allow for year-round power generation. It also gives the operator the flexibility to generate power only during peak periods. This will provide higher feed-in tariff value and improves the economics of the biogas plant. Thus, the utility value of the biomass is improved through application of AD for sugar mill wastes. Future techno-economic assessments should indicate the most feasible layouts and operational strategies for codigestion plants.

1.7 Digestate management and use

The mass balance and nutrient distribution in the whole digestate and after solid-liquid separation is presented in Table 4 and Figure 3, respectively. The whole digestate had a solids content of 6.1%. An attempt to improve the nutrient content of the digestate was made by separating the digestate into solid and liquid fractions using a decanter centrifuge. Results showed that the solid fraction with 30% solids and 74% w/w by mass accounted for 41, 71 and 71% of total Kjeldahl nitrogen (TKN), phosphorous pentoxide (P_2O_5) and potassium oxide (K_2O) content of whole digestate, respectively. On the other hand, the liquid fraction (1.2% solids) accumulated the remaining TKN, P_2O_5 and K_2O (see Table 4).

Table 4. Mass balance of nutrients in the digestate before and after solid–liquid separation using a decanter centrifuge.

	Dry matter	TKN	P_2O_5	K_2O
	(%)	(kg/d)	(kg/d)	(kg/d)
Whole digestate	6.1	383	642	275
Solid fraction	30	157	456	195
Liquid fraction	1.2	226	186	80
Digestate concentrate	11	203	186	80
Digestate condensate	0	23	0	0

The nutrient content and fertiliser value of different fractions of digestate are presented in Table 5. The N, P and K fertiliser content (%) in digestate were 1:0.7:0.6. Separation of the digestate into solid and liquid fractions did not improve the fertiliser value of the fractions. Solid digestate had N:P:K values of 0.15:0.19:0.16. One option is to dry the solid fraction and sell it as soil conditioner. Based on the nutrient value, the solid fraction can be sold at $10/t. The liquid fraction (1.2% TS) with relatively low N content (0.93 g/kg FM) will be recycled as process water. An attempt was made to improve the fertiliser value of the liquid by using evaporation technology (see Table 5). Evaporation of the liquid fraction with 90% volume reduction can concentrate (27.96 t/d) the N:P:K content to 0.65:0.26:0.21 but will incur an energy requirement of 540 kWh/d. The market value for this product has been estimated to be $15.72/t. Mixing the dried solid fraction with the concentrate did not improve the overall value of the product as fertiliser and thus its market value remained low ($10.50/t). Thus, recycling of the liquid fraction as process water in the biogas plant and sale of solid digestate are the best digestate management options.

Table 5. Nutrient content and economic value of the solid digestate, concentrate from evaporation of liquid digestate, and mixture of solid digestate and concentrate.

				Nutrients market value			
Product type	**N**	**P**	**K**	**N**	**P**	**K**	**Total**
	(%)	(%)	(%)	($/d)	($/d)	($/d)	($/d)
Solid digestate	0.15	0.19	0.16	212	254	150	616
Concentrate from evaporator	0.65	0.26	0.21	272	104	61	439
Solid digestate and concentrate mix	0.27	0.21	0.17	486	358	211	1,056

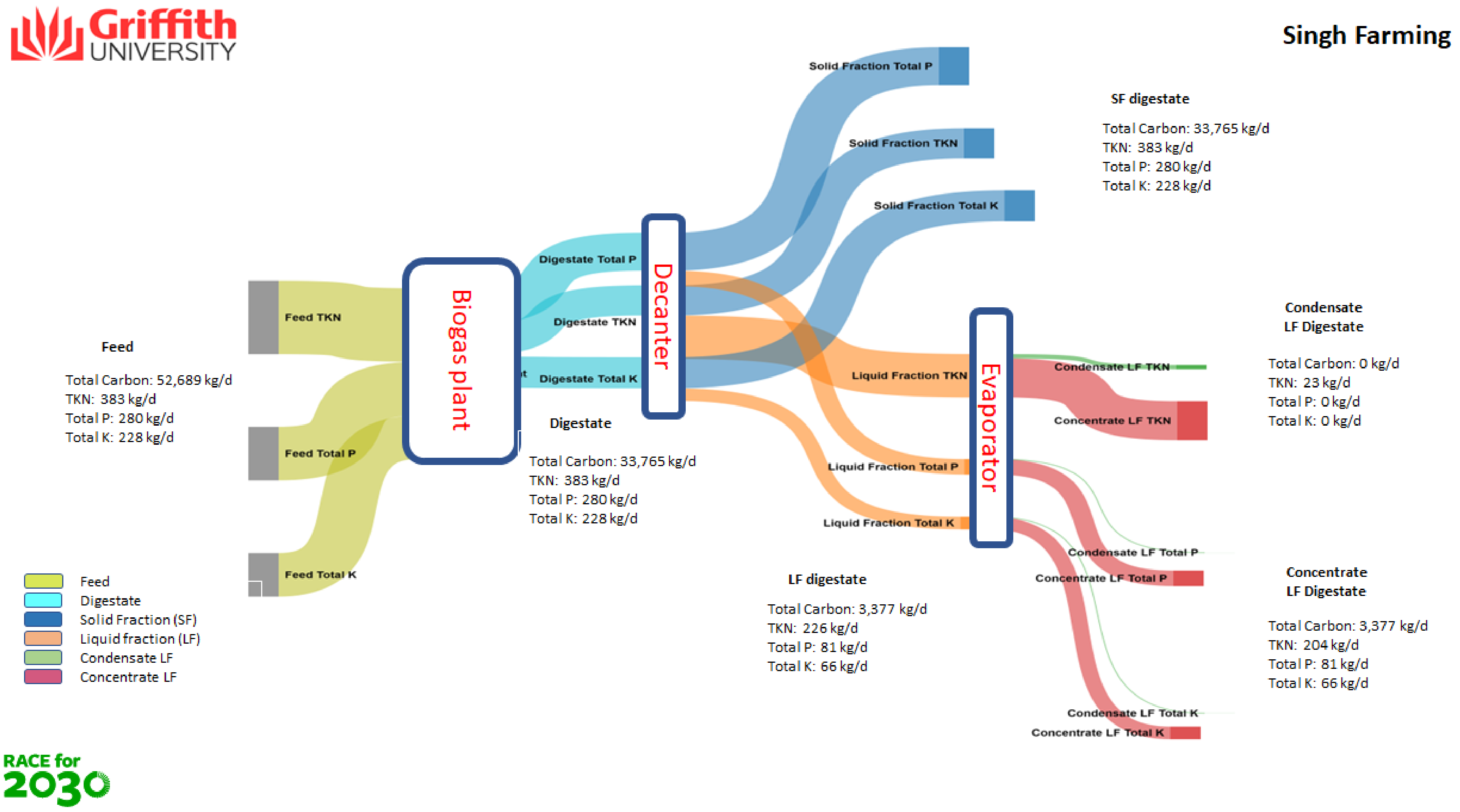

Figure 3. Mass balance of nutrients in anaerobic digestate before and after solid–liquid separation and evaporation of liquid fraction of digestate.

1.8 Greenhouse gas emission reduction

Table 6 presents the annual greenhouse (GHG) emissions that could be avoided on adopting AD technology for generating renewable biogas and using it for heat and electricity generation (Scenario 1), BioCNG (Scenario 2) and BioRNG (Scenario 3). Total GHG emissions from fossil fuel use in the transport of 5,000 t/a of chicken manure has been estimated at 50 t/a carbon dioxide equivalence (CO_2-e). Emissions from the transport of bagasse and mill mud is not included as these two feedstocks are available on site. GHG emissions from their current business-as-usual (BAU) applications *vis-à-vis* as feedstocks in AD process were also calculated. Diverting 30,000 t/a of mill mud from current stockpiling (BAU) to an AD pathway would avoid 29,944 t/a CO_2-e. Similarly, diverting 20,000 t/a of bagasse from combustion in boilers (BAU) to an AD pathway would avoid 269 t/a CO_2-e, while diverting 5,000 t/a of chicken manure from composting (BAU) would avoid 105 t/a CO_2-e. Thus, the total GHG emissions avoided from current management practices of these feedstocks was estimated to be 30,318 t/a CO_2-e. Renewable energy in the form of heat and electricity generation in Scenario 1 could replace 15,429 t/a CO_2-e of emissions generated from equivalent heat produced from natural gas and electricity from coal, respectively. Similarly, use of biogas for BioCNG production and use in Scenario 2 could avoid 7142 t/a CO_2-e emissions from natural gas. Finally, the annual emissions saved on the use of anaerobic digestate in the studied scenarios is about −354 t/a CO_2-e. Overall, the net GHG emissions avoided in Scenario 1 were 45,343 t/a CO_2-e, which is 6,942 t/a CO_2-e more than the values obtained for Scenarios 2 and 3.

Table 6. Annual greenhouse gas emission balance for anaerobic codigestion of sugar mill by-products with chicken manure.

Greenhouse gas emissions	Scenario 1	Scenario 2	Scenario 3
	(t/a CO_2-e)	(t/a CO_2-e)	(t/a CO_2-e)
1. Greenhouse gas emissions from fossil fuel use			
a. Transport of chicken manure	−50	−50	−50
2. Emissions from diverting current management practices			
a. Stock piling of mill mud	29,944	29,944	29,944
b. Bagasse as solid fuel in boiler	269	269	269
c. Composting of chicken manure	105	105	105
Subtotal	**30,318**	**30,318**	**30,318**
3. Emissions from replacing fossil fuel electricity or natural gas			
a. Electricity generation	15,429	1,345	1,499
b. Natural gas	–	7,142	7,142
Subtotal	**15,429**	**8,487**	**8,641**
4. Emissions on replacing inorganic fertiliser with digestate			
a. Emissions from equivalent N fertiliser production (urea) and application	287	287	287
b. Emissions from digestate application	−478	−478	−478
Subtotal	**−191**	**−191**	**−191**
Total	**45,506**	**38,564**	**38,718**

1.9 Economic analyses

For economic analyses, capital costs (CapEx), operating costs (OpEx), revenue and return on investment (ROI) along with payback period (PBP), net present value (NPV) and internal rate of return (IRR) were calculated. In addition, sensitivities to different project parameters were also calculated and compared for the three studied scenarios. The economic assessment undertaken is based on the best available data and uses a combination of internal plant and equipment cost data and literature reports adjusted for plant size. Where equipment cost data are used, the associated discipline costs for installation have been apportioned based on industry experience for the delivery of process plants within Australia. Operating costs are determined independently for each of the four main components. There remains an opportunity to integrate elements of plant operation and further reduce these costs by examining the control systems and remote monitoring and through more detailed analysis. Economic analyses were carried out for plant life of 25 years and that there is no assumed change to plant outputs over the course of its life.

Project CapEx includes the following parameters:

- project development fee
- engineering, procurement, and construction management (EPCM)—18% of CapEx
- plant equipment
- plant infrastructure (civil works, concrete works, roads, pipe work, powerlines)
- plant commissioning
- contingency—30% of total CapEx.

Project OpEx includes the following items:

- electricity to plant
- biomass ensilation
- BioRNG grid connection metering
- O&M costs.

The operation and maintenance (O&M) cost estimate represent a site-based attendance for plant operation and as-required maintenance regime and is based on a percentage of the mechanical and electrical equipment as well as manpower estimates. An estimated 8% of the CapEx including contingency was considered as O&M costs. The following assumptions have been used for the financial modelling:

- Feedstock cost of $40/t of chicken manure and $25/t of sugarcane bagasse and $0/t of mill mud.
- Fossil fuel electricity cost at $160/MWh to meet parasitic electrical and heating demand of the biogas plant.
- Biomass ensilation cost of $0.16/kg.
- Biomethane grid connection metering cost of $0.8/GJ.
- Biogas plant revenue was calculated at sale prices of $8.5/GJ of BioRNG to grid, $16/GJ for BioCNG and $200/t for uncompressed food-grade BioCO_2.
- Feed-in tariffs of $85/MWh for electricity to grid injection and sale of solid digestate at $10/t as soil conditioner.
- Liquid digestate sale is not considered due to low nutrient content.
- Australian Carbon Credit Units (ACCUs) at $30/t CO_2-e and green certificates at $3/GJ were considered in the financial model. ACCUs were calculated for the total GHG emissions avoided from use of renewable energy and the associated GHG emissions (see Table 6). Green certificates were calculated for energy content in the biomethane produced.

Profitability Analysis

The profitability of the plant was assessed using four metrics:

- the return on investment (ROI)
- the payback period (PBP)
- the net present value (NPV)
- the internal rate of return (IRR)

The NPV represents the economic value of the project at present by considering the time value of money throughout the project lifetime of 25 years. A positive NPV indicates economic feasibility.

$$NPV = -TCI + \sum_{n=0}^{N} \frac{CF_n}{(1+r)^n}$$

TCI – Total Capital Investment Cost

CF_n - cash flow of the year n

r – discount rate

The payback period (PBP) expresses the period which is necessary for full investment recovery.

$$PBP = \frac{TCI}{P_{NET}}$$

P_{NET} – net yearly profit.

The IRR corresponds to the discount rate when the NPV becomes zero.

The ROI is the percentage of the investment recovered in a year of operation.

$$ROI = \frac{P_{NET}}{TCI}$$

- NPV was calculated at a discount rate of 10%.
- Cash flow was scheduled at an inflation rate of 0% at the start of the project Year 1 and then NPV was calculated at a fixed net income over the project life of 25 years. About 80% of CapEx payment is scheduled in the Year 1 and the remaining 20% in Year 2.

1.9.1 Capital cost (CapEx) estimate

Table 7 and Figure 4 summarise CapEx for the three studied scenarios. The general breakdown of the individual categories of CapEx into sub-components depends on the equipment of the biogas plant's process line with some significant and recurring categories of expenditure. Total CapEx increased from $13 million in Scenario 1, when biogas was used for 100% heat and electricity generation in CHP, to $15–16 million, when the biogas is upgraded and compressed to BioCNG (Scenario 2) or to BioRNG (Scenario 3). Investment in both CHP and biogas upgrading equipment in Scenarios 2 and 3 would incur an additional CapEx of $3–4 million. Of the total CapEx, biogas plant alone accounts for 77% in Scenario 1, 66% in Scenario 3 and 63% in Scenario 2.

Thus, the total investment required varied from a low of $20 million for Scenario 1 to $24–25 for the other two scenarios (Table 7).

1.9.2 Operating cost (OpEx) estimate

OpEx costs were calculated and are presented in Table 7 and Figure 4. O&M costs accounted for 8% of the CapEx and thus varied slightly from Scenario 1 to Scenario 3. The major operating cost is derived from the cost of the feedstock (bagasse and chicken manure import) and biomass storage with this cost representing ~37–42% of total operating costs. In Scenarios 1 and 3, O&M accounted for 58% of OpEx costs. The corresponding values for Scenario 2 was 62%.

Table 7. Indicative cost-estimation of the overall project for the studied Scenarios 1–3.

Project parameters	Scenario 1	Scenario 2	Scenario 3
	($, $/year)	($, $/year)	($, $/year)
CapEx			
Development fee	700,000	700,000	700,000
Biogas plant	10,818,365	13,766,027	12,888,427
Infrastructure	1,539,460	1,539,460	1,539,460
Commissioning costs	261,786	261,786	261,786
CapEx total	**13,319,611**	**16,267,273**	**15,389,673**
CapEx contingency	3,995,883	4,880,182	4,616,902
CapEx total including contingency	**17,315,495**	**21,147,455**	**20,006,575**
EPCM fee	3,116,789	3,806,542	3,601,184
Investment required	**20,432,284**	**24,953,997**	**23,607,759**
OpEx			
Electricity	–	–	–
Feedstock cost	700,000	700,000	700,000
Biomass ensilage	320,000	320,000	320,000
Biomethane grid connection metering	–	–	110,884
O&M cost	1,385,240	1,691,796	1,600,526
Total OpEx	**2,405,240**	**2,711,796**	**2,731,410**
Revenue			
BioRNG—to grid	–	–	1,178,145
BioCNG—bottled	–	2,217,685	–
Green certificate	–	415,811	415,816
BioCO_2	–	1,016,811	1,016,811
ACCUs	1,365,185	1,156,912	1,161,537
Electricity—grid	1,639,384	142,876	159,257
Solid digestate	379,494	379,494	379,494
Revenue—total	**3,384,062**	**5,329,593**	**4,311,060**
ROI (% pa)	4.8	10.5	6.7
IRR (% pa)	1.1	9.2	4.2
Payback period (years)	21	10	15
NPV ($)	-10,579,827	-1,303,418	8,559,099

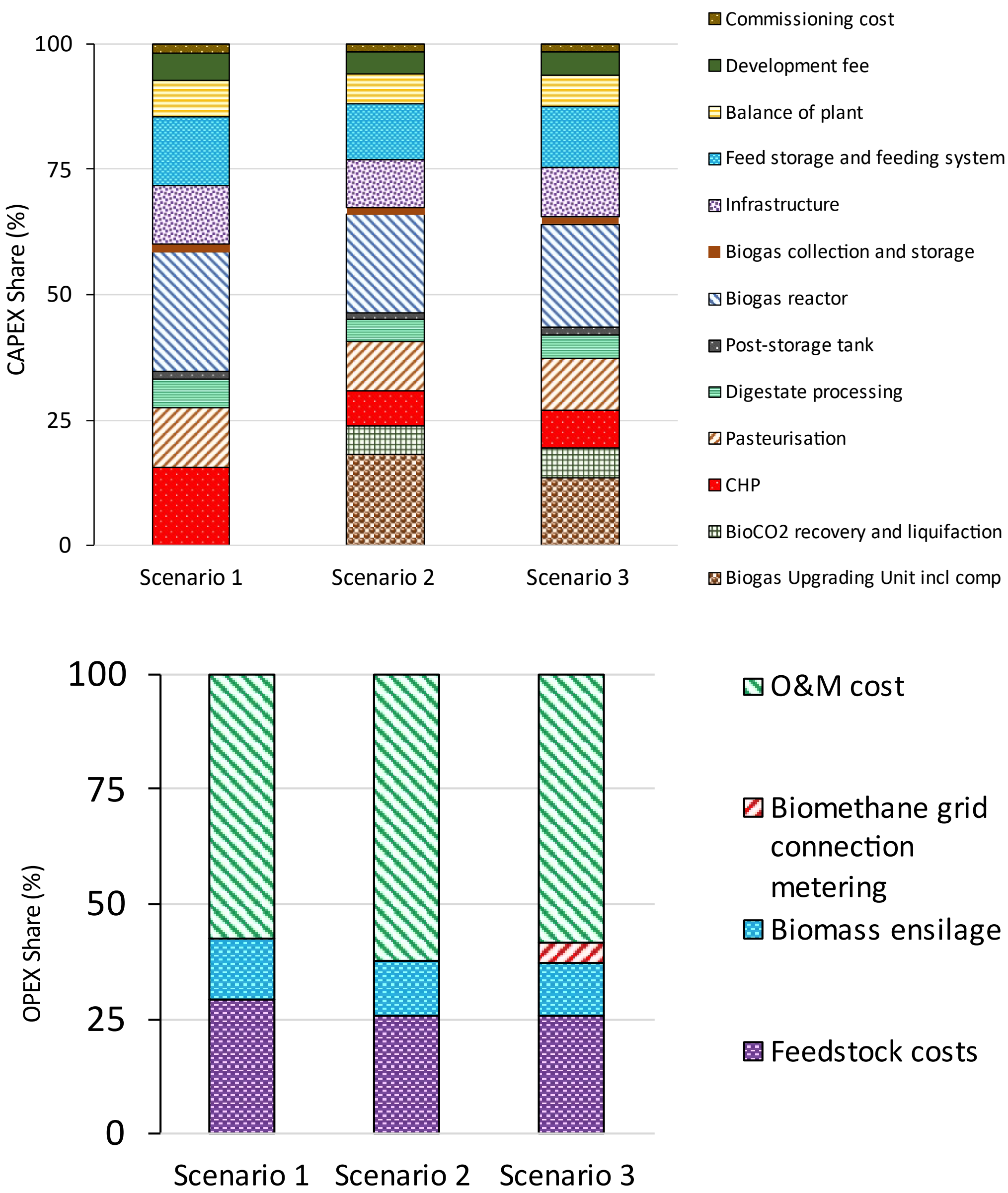

Figure 4. OpEx and CapEx cost breakdown for biogas production and use comparison between Scenario 1 (CHP + electricity), Scenario 2 (CHP + BioCNG) and Scenario 3 (CHP + BioRNG).

1.9.3 Revenue and ROI

Earnings (earnings before interest, tax, depreciation and amortisation or EBITDA) analysis was undertaken for the project to assess aspects associated with operating cash flows. The results of this analysis are shown in Table 7 and Figure 5. The data shows that the project concept at the scale of 2.2 MW biogas plant would result in revenue of ~$3.4 million per year for Scenario 1 and $4.3 million for Scenario 3 while Scenario 2 would generate $5.3 million per year. In Scenario 1, 48% of revenue would result from the sale of electricity to the grid while the remaining revenue comes from ACCUs and sale of solid digestate.

However, ACCUs are not currently available in Australia and a methodology to ascertain methane emissions from these feedstocks is required. Sale of BioCNG and BioCO_2 in Scenario 2 accounted for 60% of the revenue. Internalising the environmental benefits of avoided GHG emissions through inclusion of ACCUs and green certificates, the ROIs for the studied scenarios are 4.8, 10.6 and 6.7% for Scenarios 1, 2 and 3, respectively. Conversely, ROIs without ACCUs and green certificates would be −1.9 to 4.2%. Thus, ACCUs

($30/t CO_2-e) and green certificates ($3/t CO_2-e) play an important role in making bioenergy projects such as this economically viable and provide confidence to investors.

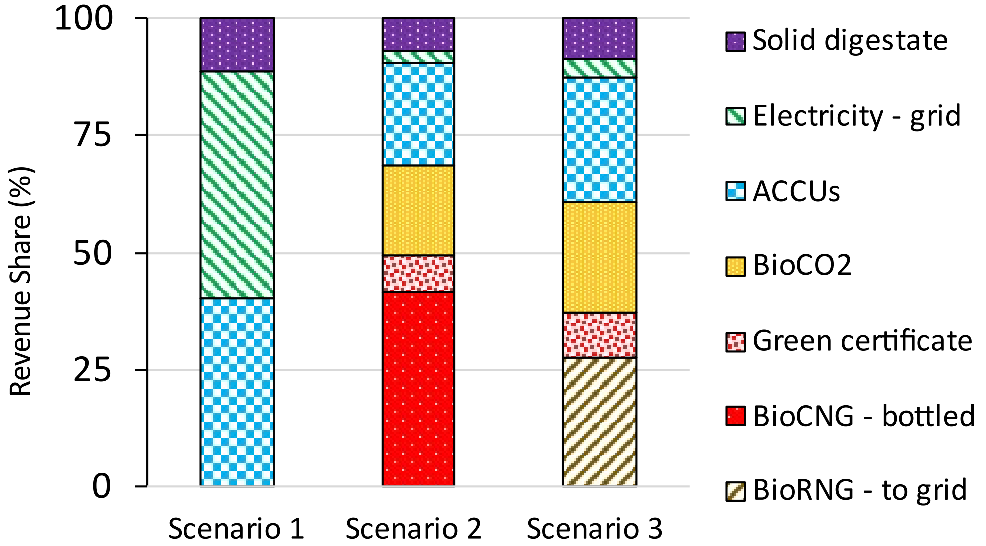

Figure 5. Revenue breakdown for biogas production and use comparison between Scenario 1 (CHP), Scenario 2 (CHP + BioCNG) and Scenario 3 (CHP + BioRNG).

1.10 Sensitivity analysis

Table 8 and Figure 6 present the results of a sensitivity analyses carried out to understand the importance of feedstock gate fees, government grants, feed-in tariffs and ACCUs in improving the revenue and thereby ROI of bioenergy projects. The influence of feedstock gate fees of $0–50/t for future organic wastes (e.g. food organics and garden organics (FOGO) or food wastes) showed that an increase in gate fees will increase the ROI linearly. Overall, Scenario 2 showed the best response to an increased gate fee, indicating that use of biogas for BioCNG and sale of surplus electricity will bring better economic ROI. In Europe especially in Denmark and Germany, feedstock gate fees of €20–40/t have been widely used. Similarly, the influence of investment grants on ROI showed that any investment grant support <30% of the total CapEx will have only marginally increase ROI. On the other hand, an investment grant support of >40% of total CapEx will have a significant impact on ROI. As expected, an increase in the feed-in tariff price for electricity from $0.085/kWh to $0.21/kWh increased the ROI linearly. Similarly, ACCU prices of $30–70/t CO_2-e also showed a similar trend as that of gate fees, indicating that both gate fees and ACCUs are the major economic parameters required to make these bioenergy projects economically viable.

The scale of production was calculated at four different plant sizes - 2.2 MW, 4.4 MW, 6.6 MW and 8.8 MW. CapEx was increased by 50% from 2.2 MW plant to 4.4 MW and 6.6 MW. On the other hand, OpEx increased linearly by 20% and 30% from the 2.2 MW plant size to the 4.4 and 6.6 MW plants, respectively. For the 8.8 MW plant size, CapEx increased by 100% while OpEx increased by 40% than the 2.2 MW plant.

Table 8. Sensitivity analyses of plant size on financial parameters for Scenario 1 (CHP), Scenario 2 (CHP + BioCNG) and Scenario 3 (CHP + BioRNG).

Plant size (MW)	2.2	4.4	6.6	8.8
(GJ/d)	380	759	1,139	1,519
Scenario 1				
ROI (%)	4.8	12.7	22.9	24.9
PBP (year)	21	8	4	4
NPV—25 years, 10% DR[1] ($million)	-10.6	3.8	29.5	45.9
IRR (%)	1.1	11.8	22.8	24.8
Scenario 2				
ROI (%)	10.5	19.8	33.3	35.1
PBP (year)	10	5	3	3
NPV—25 years, 10% DR ($million)	-1.3	26.5	67.8	97.7
IRR (%)	9.2	19.5	33.3	35.1
Scenario 3				
ROI (%)	6.7	15.1	26.5	28.4
PBP (year)	15	7	4	4
NPV—25 years, 10% DR ($million)	- 8.6	11.5	44.4	66.7
IRR (%)	4.2	14.5	26.4	28.4

Notes 1 DR: discount rate

Overall, scale of production has a more profound influence on the ROI and production costs of electricity, BioCNG and BioRNG than any of the parameters studied (Figure 7 and Table 8). When increasing the plant design capacity from 2.2 to 8.8 MW, the cost of electricity production drops sharply when the plant size is increased from 2.2 to 4.4 MW and then drops more steadily as the plant size is increased from 4.4 to 8.8 MW. At the same time, the ROI increases significantly when the plant size is increased from 2.2 to 6.6 MW and flattens thereafter. Both these results suggest that a large-scale centralised biogas plants with an average plant size of about 6.6 MW and digesting 450 t/d of feedstock would be economically viable in Australia with a ROI of 27–33%.

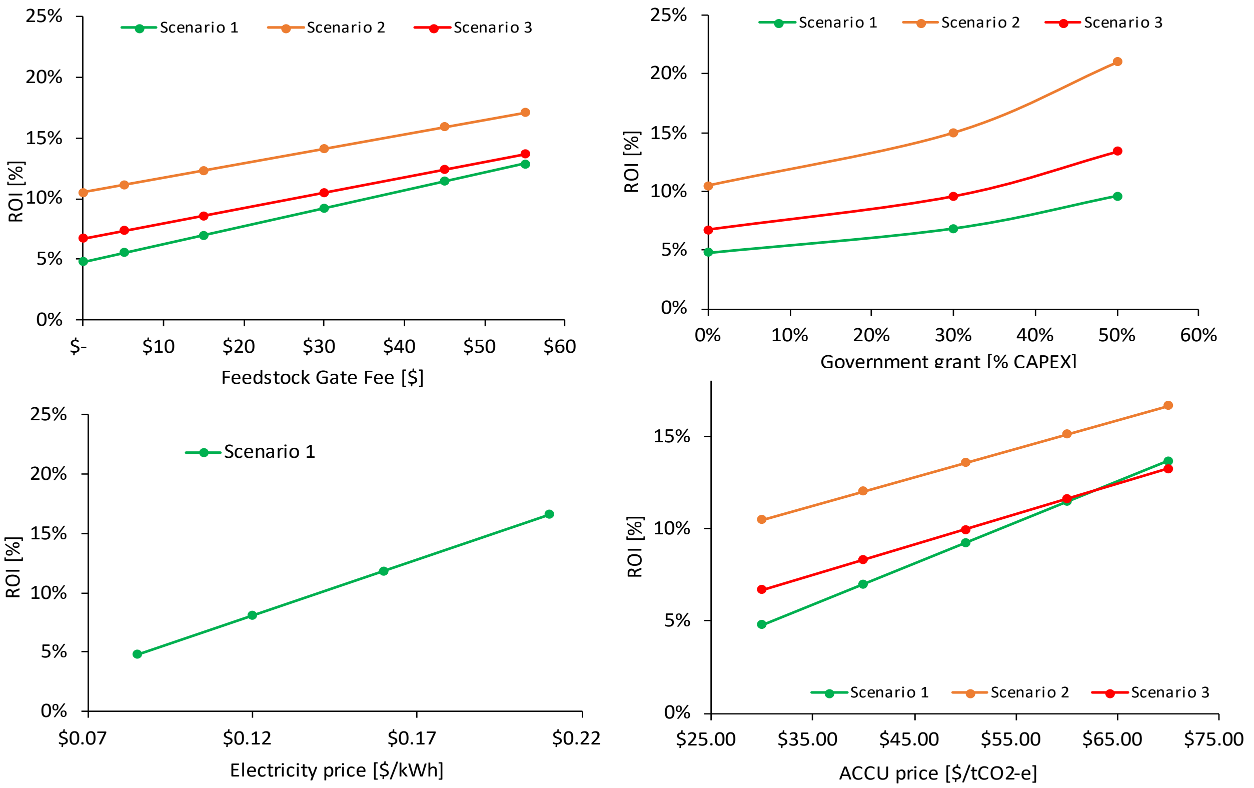

Figure 6. Sensitivity of feedstock gate fee (top left), government grants (top right), electricity price for Scenario 1 (bottom left) and ACCUs (bottom right) on the return on investment (ROI) for Scenario 1 (CHP + electricity), Scenario 2 (CHP + BioCNG) and Scenario 3 (CHP + BioRNG). Please note that Scenarios 2 and 3 use biogas for BioCNG and BioRNG production, rather than electricity production, so are not present on the electricity price figure as they do not export electricity.

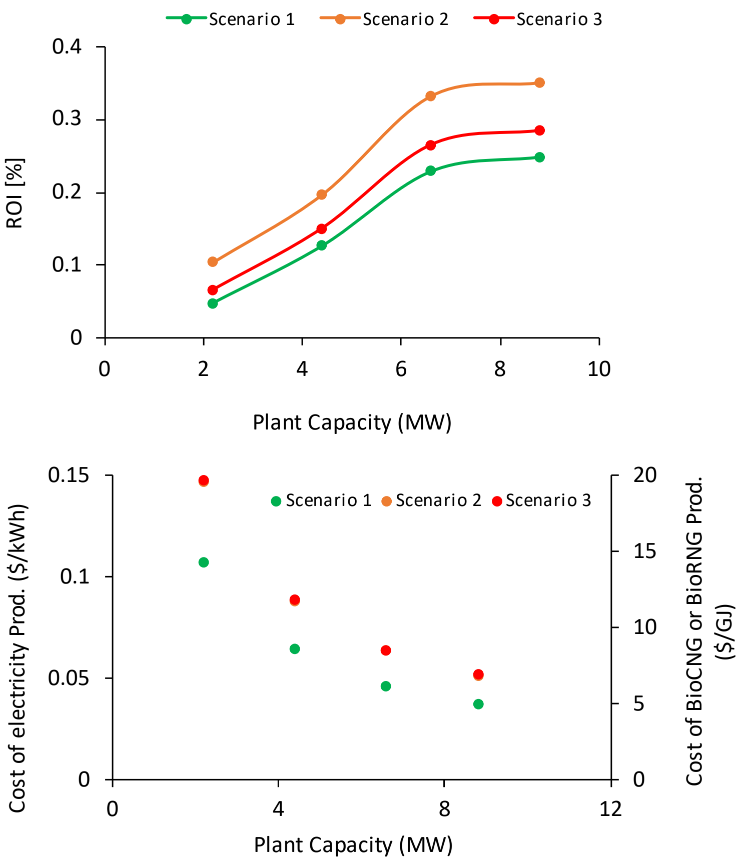

Figure 7. The influence of plant capacity on return on investment (ROI, %) and cost of electricity ($/MW), BioCNG ($/GJ) and BioRNG ($/GJ) for Scenario 1 (CHP + electricity), Scenario 2 (CHP + BioCNG) and Scenario 3 (CHP + BioRNG). Please note that the values for costs in Scenarios 2 and 3 are identical, so Scenario 2 is also represented by the red dots.

The cost of production of electricity (in $/kWh) or biomethane (in $/GJ) is presented in Figure 7. The cost of production of electricity decreased from $0.11/kWh at a 2.2 MW plant size to $0.04/kWh when the plant size reached 8.8 MW. Similarly, the estimated cost of biogas upgrading and feeding biomethane into the natural gas grid decreased from $19.71/GJ at 735 m^3/h of raw biogas upgrading capacity to $6.9/GJ when the upgrading capacity is 2940 m^3/h raw biogas. For BioCNG production, the cost of production decreased with an increase in upgrading capacity from $19.56/GJ (750 m^3/h raw biogas) to $6.84/GJ (3000 m^3/h raw biogas).

1.11 Conclusion

The study shows that a 2.2 MW biogas plant can generate approximately 9.35 million Nm^3 of biogas per year through codigestion of 20,000 t/year of sugarcane bagasse and 30,000 t/year of mill mud with 5,000 t/year of locally available chicken manure. Nonetheless, it is necessary to further improve the energy and product efficiency to make the biogas plant economically viable. Financial analyses show that the total investment required for the biogas plant could vary from $20.43 to 24.95 million and depends on the technology and equipment used for biogas use. However, the ROI depends on the revenues generated especially from variable parameters such as feedstock gate fees, government investment grants and guaranteed feed-in tariffs, ACCUs and green certificates. Internalising the environmental benefits of avoided GHG emissions through inclusion of ACCUs and green certificates, the ROIs for the studied scenarios are 4.8, 10.5 and 6.7% for Scenarios 1, 2 and 3, respectively. Conversely, ROIs without ACCUs and green certificates would be −1.9 to 4.2%. Sensitivity analyses showed that an AD plant of 6.6 MW capacity will significantly reduce costs and become among the most competitive technologies in renewable energy and carbon markets with ROIs of 27–33%. Thus, onsite production and/or use of renewable energy will enable farmers to achieve sustainable management of agricultural wastes and help to decarbonise the agricultural sector.

Far Northern Milling, owners of Mossman Sugar Mill, have selected Helmont Energy as the proponent of their AD project, and plan to achieve practical project completion by 2024.

2 Commercialisation of the biogas plant

2.1 Commercialisation stages

This project is intended to complete the first stage of a six-stage process towards a highly innovative, full-scale commercial biogas plant. The commercialisation pathway for the project is outlined below:

1. **Stage 1 (six months)** — This fast-track project has been conducted to determine the biochemical methane potential (BMP) of a range of organic waste feedstocks that are readily available in rural areas. Sugarcane growing areas were of particular interest owing to logistics and the availability of highly concentrated biomass such as sugarcane bagasse, trash and mill mud from sugar mills. Both mono- and codigestion of the above feedstocks were completed. Based on the results obtained, the techno-economic analyses have been carried out to evaluate the feasibility and minimum supply of feedstock required to support the construction of a commercial-scale biogas plant. Three different scenarios on the use of biogas for electricity, BioCNG with CHP and BioRNG with CHP production were evaluated.
2. **Stage 2 (12 months)** — In Stage 2 of the commercialisation pathway, we will optimise the organic loading and codigestion ratios. This will first be conducted at lab scale before evaluating the process performance and methane yields using the Griffith University pilot-scale biogas plant (4 × 1.2 m^3 stainless reactors). The produced biogas will be upgraded to BioCNG using the Griffith University pilot-scale biogas upgrading and compression unit (10 m^3/h raw biogas). This is expected to require 12 months of research and cost ~$120,000. We will seek funding under RACE for 2030, industry partners and/or other government programs.
3. **Stage 3 (six months)** — In Stage 3 of the project, a range of potential commercial uses for the digestate from the pilot-scale biogas plant will be tested, which will be critical to the success of any biogas project. This is expected to require six months of research and cost $35,000. We will seek funding under for RACE for 2030, industry partners and/or other government programs.
4. **Stage 4 (six months)** — The pilot-scale studies will be used to design the AD process, physical plant component sizes and layout for commercial-scale operations. A biogas plant blueprint will be created for commercial businesses to successfully construct and operate a biogas plant. This is expected to require six months and cost $35,000. We will seek funding under for RACE for 2030, industry partners and/or other government programs.
5. **Stage 5 (two years)** — Private equity will fund the construction and operation of the biogas plant(s). Strong interest to invest in such projects is being expressed in the media (e.g. AGL, Origin, ENGIE and Jemena). The investment required for a biogas project producing 9.35 million m^3 of biogas per annum to produce 2.2 MW of electric power is expected to be approximately $20-$25 million. However, a 6.6 MW biogas plant has to be considered to make it economically viable. It is estimated that 6.6 MW biogas plant would be $30-37.5 million. Upgrading the biogas to CNG (250 m^3/h raw biogas) will require a further investment of $600,000 for a 2.2 MW plant or $0.9 million for 6.6 MW plant. A review of available funding sources through private equity and grant funding will be performed to identify alternative business models to aid in project delivery and maximise success.
6. **Stage 6 (six months)** — The commissioning of the proposed full-scale biogas plant. The final outcome of this project will be to meet with prospective stakeholders (including processors, companies, and/or end users) to present business case options and seek long term contracts from companies to participate in a value chain approach for specific waste streams to build a commercial-scale biogas plant.

Some of the above stages will be carried out simultaneously so that the commissioning of the biogas plant can take place during or before 2025.

2.2 Barriers, policies and regulations on commercialisation of project

2.2.1 Technical and compliance barriers

While the proposed project has the potential to make a significant contribution to the government's carbon and emissions reduction targets, several technical and regulatory barriers currently exist to developing a biogas plant in Australia. Specific barriers that have the most significant impact on the viability of bioenergy production from agricultural waste are discussed below. The proposed technical strategy can address these barriers and improve the project viability. For instance, increasing the scale of projects can reduce relative electricity production or biomethane costs. This will also increase confidence among farmers to supply their feedstock. Thus, reducing barriers and creating a demonstration project in a highly intensive agricultural region can improve the commercialisation of the project.

Guarantee of Origin certification scheme

There is currently no mechanism to demonstrate the carbon reduction benefit of biogas and biomethane in Australia. Thus, the biogas produced in this proposed project has no intrinsic value to a wider market and therefore will not attract any premium over the prevailing natural gas commodity price. Including biomethane in the Guarantee of Origin certification scheme will enable Australian businesses to sell domestically, and to the world, verified low emissions fuels derived from renewable sources, such as hydrogen and biogas, as well as fossil fuels with substantial carbon capture and storage. Guarantee of Origin certification will enable biomethane use to be recognised and allow users to reduce reportable carbon emissions (either voluntarily through CERT or mandatorily through NGER). The Guarantee of Origin scheme underpins the government's clean hydrogen future and is an essential aspect to allow the biomethane produced in this project and injected into the gas network to support hydrogen production as a primary feedstock. Inclusion of the Guarantee of Origin scheme in this program will enable the project to demonstrate the applicability of Guarantee of Origin certification mechanism for biomethane produced sustainably from agricultural waste.

Energy Reduction Fund registration

Currently, sugar industry residues such as sugarcane bagasse, mill mud, cane tops and trash are not accredited under approved methods of the Energy Reduction Fund (ERF). Projects using these wastes are therefore not currently eligible to create Australian Carbon Credit Unit (ACCU) certificates. Acceptance by the Clean Energy Regulator (CER) into the ERF will reduce the cost of biomethane to consumers and increase the availability of agricultural resources. It also increases the supply of ACCUs, providing entities with increased access to carbon offsets to meet voluntary targets. Development of a new ERF method is essential to support the carbon calculations required for ACCU certification.

Mechanisms to recognise secondary products

The proposed biogas plant produces secondary products such as BioCO_2 and digestate. Acceptance and certification of these AD by-products will allow the carbon reduction potential to be recognised. This will also create new markets, increase the revenue profile of similar projects and make investment more attractive and biomethane cheaper to end users. Currently, digestate is considered as waste in Queensland. Engagement with the CER, EPA and other regulatory bodies in Queensland to establish appropriate accreditation mechanisms for each of the secondary products is necessary to support removal of any barriers and improve the uptake of these secondary products, particularly biogenic CO_2 and organic fertiliser.

Biomethane quality compliance with AS 4564: Specification for general purpose natural gas

The biomethane produced from this and other biomethane production projects will not meet the gas quality specifications as set out in the National Gas Rules (which includes AS 4564-2011 and the Gas Safety (Gas Quality) Regulations), or AEMO's *Gas Quality Standard and Monitoring Guidelines* (AEMO 2016)[4]. Without update and revision of these requirements, the biomethane produced can only be delivered to customers through the existing gas network after expensive biogas cleaning and upgrading processes. Projects will incur substantial costs associated with the treatment of biomethane to a quality that meets the requirements for injection into the gas network under AS 4564. Revised biomethane standards will reduce costs and simplify the technical process required to inject biogas and biomethane into the gas network without unnecessary additional treatment.

Compliance of offshore equipment with Australian Standards

The electrical and electronic equipment for control and monitoring of AD plant along with mechanical and biomethane upgrading and carbon dioxide recovery are likely to be imported from offshore suppliers owing to the increased maturity of the European and North American anaerobic digestion markets. These suppliers do not comply with relevant Australian Standards as their products are currently not supplied into Australian markets. The costs associated with compliance of European products to Australian standards is estimated at 30% of capital costs. Without this technical certification, biomethane projects cannot be developed in Australia. Based on our personal experience with Griffith University's pilot-scale biogas plant and from other industries, we can achieve this compliance certification. However, streamlining the specific requirements for certification by local consultants and manufacturing industries can support the overseas suppliers to build locally and thereby reduce the costs of project implementation.

Substrate availability

Considering seasonal variations in the availability of sugar mill by-products, feedstock storage is required to provide consistent feeding of the biogas plant. Monitoring the amount and types of the supplied feedstocks at the plant is essential. Sugarcane bagasse and mill mud if stored improperly can lead to rotting and nutrient leaching during rainfall events or spontaneously combust during the dry season. Ensilation of sugarcane bagasse and mill mud with lactic acid bacteria can ensure the preservation of biomass under an anaerobic environment and thereby prevent further degradation and/or environmental impacts.

Substrate composition

Sugarcane bagasse and chicken manure features high total solids (TS) and fibre contents and slow degradability. For digestion of these type of feedstocks, operation of biogas plants at the designed organic loading rate and hydraulic retention times along with a robust feeding technology and mixing are required under high TS concentrations in wet digestion systems. However, pre-treatment technologies should be considered to promote positive effects on rheology, increased degradability and gas production, and a reduction of the necessary retention time.

The carbon-to-nitrogen (C/N) ratio in the sugarcane bagasse is high. It is critically important to improve this ratio to facilitate better conversion of lignocellulosic biomass to methane. An optimal C/N ratio of 20–30 needs to be properly maintained in order improve the process stability and methane yield. To ensure efficient AD, an

[4] AEMO (2016). Gas quality standard and monitoring guidelines. gas-quality-standard-and-monitoring-guidelines-declared-transmission-system.pdf (aemo.com.au)

appropriate C/N and balance among the main nutrients can be achieved through codigestion of sugarcane bagasse and mill mud with chicken manure. BMP studies in the project showed that addition of chicken manure to codigestion of bagasse and mill mud improved methane yields by 40%. Further improvement can be achieved by the addition of trace elements.

General plant process performance and monitoring

To ensure that the plant is technically fully operational, a regular check of the technical equipment (e.g. digester technology, mechanic feeding, temperature regulation, stirring or pumping systems, CHP, biogas upgrading unit) is common practice. On-line monitoring and control such as temperature, pH, alkalinity, as well as the detection of the produced biogas amount and the gas composition are essential. These parameters should be measured continuously on a daily basis. Engaging experienced operators also helps to manage this risk.

Gas explosion

Methane is an explosive gas with a lower explosive limit (LEL) of between 50,000 and 150,000 ppm or 4.4% by volume (AS/NZS 60079.1.2012). At room temperature and standard pressure, methane is a colourless and odourless gas. Therefore, odorants such as methanethiol or ethanethiol are added to the biomethane to detect the methane leaks in the plant. The risk of methane leaks or explosions occur when the reactor is opened for repairs, during start-up of the plant, or from leaks in the biogas storage or upgrading facility. These risks can be managed by:

- methane detectors being worn by operators during operation of the plant or installing methane alarms (Lo: 5% LEL or 2200 ppm)
- undertaking commissioning tests
- removal of air from the storage bladder prior to filling with biogas
- reduction or purging of air from the system using water or CO_2
- ensuring biogas flaring systems comply with AS 1375: Industrial Fuel Fired Appliances Code
- ensuring all electrical equipment is intrinsically safe (International Electrotechnical Commission System for Certification to Standards Relating to Equipment for Use in Explosive Atmospheres (IECEx System) compliance) and located outside the explosion hazard zones and away from any potential biogas release point (AS/NZS 60079.10).

Thus, a competent consultant is required to design the biogas plant and in the purchase of electrical equipment.

Plant operational experience

There is a risk of losing key experienced personnel who have knowledge and capabilities important to a business delivering these new (to Australia) projects at commercial scale. Succession planning and key roles will be covered by multiple people or reliably covered by outsourcing are important factors in managing this risk.

2.2.2 Economic barriers

Risk averse and inexperienced project financiers

A lack of understanding of this new (to Australia) asset class impacts the ability to attract project financing. To overcome these risks requires that commercial project proponents demonstrate that the equipment selected is commercially available off-the-shelf and has been deployed and financed in Australia. Biogas developers in Australia typically need to carry the full cost of the project to the point of meeting project financiers 'financial close' requirements.

Gap in government funding programs

These hard costs to financial close include application and connection fees to government-owned entities (councils, state government and network owners, utility providers), which are explicitly excluded as eligible expenses under most government funding programs.

No available government incentives and high levels of sovereign risk

Other biogas and biofuel markets around the world have been incentivised by government. This is not and is unlikely to ever be the case in Australia. The politicisation of energy policy in Australia is seen as a major risk by potential project financiers. Locating energy offtakes behind the meter so that any electricity or fuel produced is supplied directly to the project proponent or a co-located tenant reduces network costs and risk. It is also prudent to assume no government incentives in commercial project economics.

Government funding of CapEx distorts market

The government funding of CapEx in some key projects has delayed the uptake of biogas in Australia as industry and financiers currently perceive the asset class to be unviable without government funding. Until there are examples at utility scale/grade with no government funding of CapEx, it is unlikely that private funding of these assets will be mainstreamed.

2.2.3 Regulatory barriers

Biogas project

There is currently no legislation, regulation or policy in Australia specifically for biogas plants, which may make it difficult to bring projects on-line or allow them to operate as designed and which could impact on the level of demand for biogas plants. Development Application (DA) approval needs to be granted for a biogas project. A DA is normally granted by local government. However, some applications are referred to state government where they are either large scale or have potential environmental impacts. The plant would meet this test and therefore would need to be referred to state government. The project aims to reduce this risk by assisting customers with obtaining all necessary approvals as well as lobbying for consistent regulation.

2.2.4 Environmental regulatory barriers

Environmental pollution

Close proximity of biogas plants to residential areas is considered a risk owing to emissions of odours, generation of dust particles, water pollution and noise pollution. All feedstocks, especially manure and mill mud, must be stored in closed containers or silos and sealed. Feed tanks, biogas reactor and digestate storage should be covered tanks and digestate separation should be performed inside the building. Solid digestate should be transported in closed trucks and storage time minimised. Liquid digestate must be returned to post-storage tanks for storage until further use as process water for substrate dilution.

Any noise created by pumps, blowers, mixers or other ancillary equipment should be minimal, intermittent and controllable locally through noise baffling. Operation of the digestor is generally silent. The biogas upgrading unit is contained within shipping containers that have sound baffling insulation to minimise noise.

The plant is sited on a concrete plinth as a stable and secure footing. As such there is no dust created from operational activities on-site. The infrastructure of the plant is fully enclosed, including the feedstock and liquid digestate pipelines.

2.2.5 Market barriers

Retrofit vehicles to operate with BioCNG

Timing of the phase-in of new vehicles that can take BioCNG would be key to reducing the costs and risks associated with retrofitting vehicles to use the new fuel. Alternatively, BioCNG can be used for power generation in local industries, especially during the peak hours.

BioCO_2 uses

BioCO_2 from biogas upgrading is relatively new and is gaining importance in Europe and the USA. The product needs to be of high purity to be sold to the food and beverage industry. The technology to separate CO_2 and liquify it is commercially available off the shelf but the quality and uptake by local greenhouses, food and beverage business or slaughterhouses presents additional risks for project financiers.

Immature digestate market

The digestate market in Australia is immature. Solid phase digestate should have a higher market value than manure, due to its high plant availability and more stable nutrient content, but at present in commercial projects only local manure market offtakes/displacement value can be assumed. Liquid phase digestate can be recycled, irrigated or more deeply refined. When more deeply refined (e.g. evaporation condensate) local agronomist crop trials and offtakes are required to justify the benefit of the liquid in displacing mainstream chemical liquids. The condensing equipment, while commercially available off the shelf, adds CapEx and OpEx. Project financiers, even international ones, are currently unconvinced of the market price and distribution arrangements able to be struck.

2.2.6 Project management

There is a risk that the construction will not be completed at the agreed cost or within the agreed schedule. This may reduce the profitability of the project. Delays in supply or increment costs of components could disrupt production schedules and project profitability. Third party subcontractors will be engaged for various aspects of the construction project to ensure the best possible outcome for shareholders. The components for the plant designs will be sourced from international manufacturers with the focus on ensuring suppliers are able to meet timelines.

3 Project short-term and long-term impacts

3.1 Identified short-term impacts

The proposed biogas plant (3 × 6,000 m^3), if implemented at Mossman Sugar Mill, will:

1. Produce 9,62,6875 m^3/year of biogas. Use of biogas for electricity production can generate (22,431 MWh/year) a new revenue stream of $1.63 million/year and avoid 20,414 t/year CO_2-e of GHG emissions. Use of biogas for BioCNG (201,198 GJ/year) and BioCO_2 (8,146.8 t/year) production can generate $3.99 million/year and avoid 2,436 t/year CO_2-e of emissions.
2. Divert 10–15% of organic wastes such as food organics and garden organics (5,000 t/year) from landfill in the regional areas (Douglas Shire) and save landfill levies of $255,000 per year (@$85/t of waste in Douglas Shire region of Cairns) for the polluter and generate additional revenue of $75,000 per year (@ $25/t) as gate fees for biogas plant.
3. Achieve savings of more than $10,000/year, for a 120-ha cane farm using $160/MWh of electricity to run a pivot irrigation system.
4. Increase the share of renewable energy in the energy mix by 1%[5] and contribute to Queensland's 2030 emissions reduction target of 30%.[6]
5. Using 55,000 t/year of feedstock consisting of sugarcane bagasse, mill mud and chicken manure in the proposed biogas plant at Mossman could replace the annual 100% diesel consumption of a medium size sugar mill (3.1 ML/year of diesel) for transport of cane from farm to mill (Kaparaju, ARENA project). The proposed biogas plant can produce 201,198 GJ/year of BioCNG, equivalent to 5.6 ML/year of diesel (@35.8 MJ/L). Use of wastewater from sugar mills can reduce the costs associated (@$0.71/$m^3$) with the treatment and disposal of wastewater by 50%. The plant will also attract new investment of approximately $100 million and could generate 10–15 direct jobs and 60 indirect jobs.
6. Local generation/replacement of grid electricity ($160/MWh) with renewable electricity (@$0.09/kWh) or BioCNG (@$16/GJ) will provide electricity input cost savings of 53% for parasitic electricity demand in Scenario 1 or 2.
7. Use of 33% of the total (37,949 t/year) solid digestate can replace 100% of inorganic nitrogen fertiliser (41.7 t/year of urea @46% N) requirement of a 120-ha cane farm (@160 kg N/ha/year) and associated GHG emissions (@0.733 t/t CO_2-e urea) of 30.6 t CO_2-e. Thus, production of digestate will create a new local organic fertiliser market. Using this digestate for crop production will reduce nitrogen and phosphorous leaching into the Great Barrier Reef by 20% for N and 10% for P.

[5] In 2019, Germany with 9,527 biogas plants produced 48,000 GWh/a of electricity and heat, comprising 3% of its electricity.

[6] In 2019, Europe produced 176 TWh of biogas and 26 TWh of biomethane from 18,855 biogas plants and 726 biomethane plants, respectively. The EU target is to produce 370 TWh of biomethane by 2030 and 1020 TWh by 2050. Australia has the potential of 100 TWh, which is equivalent to 9,000 biogas plants.

3.2 Identified long-term impacts

1. This project will assist the Australian biogas industry to lift its current generation contribution to the national grid from 0.5% to a potential 9% (21,600 GWh) by 2034, which will assist in the decarbonisation of Australia's electricity and gas networks. For instance, electricity generated by manure-based biogas reduces the GHG emission about 1.45 kg/kWh CO_2-e generated power due to the improved manure management and the substitution of the German electricity mix (Oehmichen & Thrän, 2017)[7].
2. New investment opportunities for biogas and energy from waste projects in Australia are estimated at $3.5–5.0 billion. If these are taken up, it is estimated that up to 9 million t/year CO_2-e can be avoided and 8,000 direct and indirect jobs created.
3. Use of digestate for developing speciality fertiliser would have significant environmental and economic benefits across the biogas industry in Australia. For instance, substituting 1 tonne of inorganic fertiliser with 1 tonne of digestate would save 1 tonne of oil, 108 tonnes of water and avoid 7 tonnes CO_2-e of GHG emissions. Moreover, use of digestate as biofertiliser can improve fertiliser use efficiency by 50%, reduce leaching to ground water, and improve the crop growth and yields.
4. Replacement of 5% of transport fuel consumption across Australia with BioCNG will replace 1.4 billion litres of fossil fuel and 3.5 million t CO_2-e of GHG emissions.
5. New biogas plants and their ancillary industries such as biogas upgrading, BioCNG bottling and distribution, $BioCO_2$ recovery and liquefaction, digestate to solid/liquid biofertiliser production and composting will facilitate 50–60 direct and 300–500 indirect jobs in the biogas industry by 2040.
6. Opportunities to turn agricultural waste and FOGO into renewable energy will attract significant investment to regional areas across Australia. For instance, use of 69% of total sugarcane trash (4.7×10^6 t per year), generated in Australia can replace the energy demand of 24 sugar mills (14 kWh/t cane per sugarcane mill) and 29.15 ML/year of diesel consumed for sugarcane transport. This opportunity is particularly suited to NSW and the Burdekin region in Queensland where sugarcane is burnt before harvest.
7. Once the research has been conducted for the sugarcane industry, the approach can be used as a guideline or blueprint for other similar lignocellulosic feedstocks. However, best practice requires each new feedstock mix to be tested at lab scale before a final investment decision. This will cost $20,000–30,000 for bench-scale testing.
8. The construction blueprint of a commercial scale plant that will be developed in a follow-on project could also be adopted at multiple locations using a range of different feedstocks. However, adaptations will be required to account for different outputs required at different locations (e.g. electric power or BioCNG).

3.3 Overview of technical feasibility of biogas plant

3.3.1 Biomass supply and storage

Operating costs associated with the collection, transportation, storage and handling of sugarcane bagasse and chicken manure have been estimated at $25/t and $40/t (wet basis), respectively. Total OpEx for the biomass storage and ensilation has been estimated at $1.6 million per year. However, feed-in tariffs are essential to make the project more economically attractive.

[7] Oehmichen, K. & Thrän, D. (2017). Fostering renewable energy provision from manure in Germany—Where to implement GHG emission reduction incentives. Energy Policy, 110:471–477.

3.3.2 Biomass pre-treatment

Cost estimation data for biomass pre-treatment and digestate processing continues to be based on theoretical studies with only a few publicly available studies. In the present study, maceration of sugarcane bagasse and mill mud was considered. If any thermal pre-treatment is considered, an additional CapEx of $4–5 million is required for the project.

3.3.3 Biogas plant design and fabrication

The capital cost estimates for biogas production are based on European biogas plant experience in the design and construction of biogas digesters. The equipment list identifies the key equipment elements of the digester plant and pricing is applied from the German biogas plant equipment database, matching both type and size for each element. Most equipment items for these plants are sourced from Europe and specific to the biogas industry. This equipment pricing forms the base for developing an overall cost for bringing the plant through to operation. However, application of industry percentages for installation of biogas plants in Australia is not included. Finally, the components of design, commissioning, and indirect costs (such as management) are represented by the EPCM discipline and industry percentages.

3.3.4 Biogas upgrading

To support a cost estimation of the proposed membrane biogas upgrading facility, several published economic comparisons were reviewed based on technology and throughput size evaluation. Bright Biomethane has provided the most comprehensive range of membrane-based biogas upgrading technologies with CO_2 recovery and liquefaction. Their website provides technical data sheets and forms the basis for determining a cost estimate of this facility. Data from this report has been extrapolated to provide a cost estimate.

The cost basis for upgrading the biogas incorporates the necessary biogas clean-up for not only vehicle use, 96% methane (Scenario 2), but also for injecting into European natural gas networks (Scenario 3). The membrane modules in the system are arranged in three stages. In this patented design, the permeate gas from the different stages is recirculated to obtain the highest efficiency (>99.5%) and lowest methane loss (<0.5%). This is a significantly lower methane slip value than many other biogas purification technologies. In this instance the target output is 96% methane, and this is in alignment with Australian gas quality standard AS 4564. In addition to the production of biomethane, the Bright Biomethane systems may be used to recover and liquefy CO_2 (BioCO_2) to create an extra source of revenue for the owner of the biogas plant. Zero methane slip is achieved since the small amount of methane still present in the CO_2 is recovered during the liquefaction process. When no liquid CO_2 production is required, the recovery system can be put in a standby mode that requires no additional energy. This liquid CO_2 has food grade quality and can be used in greenhouses, the food and beverage industry, refrigeration and slaughterhouses.

Internal project team data and the published economic comparisons referenced above are used to inform OpEx costs associated with biogas production and upgrading. These costs include electricity, water, maintenance and operating personnel and excluding depreciation costs. Electricity consumption for biogas upgrading and compression has been estimated at $0.27/m^3 raw biogas.

3.3.5 Digestate processing and pasteurisation

In Queensland, digestate from the biogas plant is considered as a waste (Queensland Digestate Policy, in preparation). The *End of Waste Code Anaerobic Digestion Digestate* (EOWC 010001054) requires a minimum temperature of 70°C for at least 1 hour before digestate can be applied to land or sold to users. To comply with legislation, pasteurisation of digestate is required as a post-AD process. In addition, pasteurisation is considered as a way of demonstrating the quality of the digestate and increase its value. Digestate pasteurisation systems are commercially available in the market and have been designed to handle difficult feedstocks and to maximise energy efficiency regardless of whether the feedstock is pasteurised before or after the AD process.

3.3.6 Liquid digestate condensate

The liquid fraction of the digestate is often used as process water owing to its low nutrient content and high costs of transportation. However, the liquid fraction can be converted into a valuable biofertiliser by evaporating the water. Depending on the feedstock nutrient content, the liquid fraction can be rich in key fertiliser components (NPK), although the two streams have different storage and handling requirements. Generally, biogas operators must use and incur additional cost for the disposal of the liquid digestate, meaning extra OpEx costs. In a two-stage effect digestate concentration system, the volume of liquid digestate is reduced by up to 90%, thereby increasing the nutrient content. These systems have the facility to recapture energy for use in the subsequent concentration phases, increasing energy efficiency and reusing the condensate elsewhere in the AD plant. The concentrate can then be sold in the market. Reducing its volume will decrease the expense of storage, transport, application and disposal, while preventing additional discharge to the environment.

The operating costs across downstream processing of the digestate such as solid-liquid separation, pasteurisation and evaporation, can be distinguished between variable and fixed operating costs. Variable costs fluctuate based on the plant throughput and include chemicals, wastes and utilities, their values deriving from simulation results and vendor/literature unit pricing. Fixed costs incorporate maintenance and labour costs.

4 IRG engagement

4.1 Introduction

In total four industry reference group (IRG) meetings were conducted over the course of the project to discuss project progress and obtain valuable feedback from the IRG members. Following is a summary of the topics discussed during these meetings and how they were incorporated into the project. The main objective of the project was to carry out a feasibility study for a full-scale biogas plant at Mossman, Queensland. Three different scenarios were evaluated—using biogas for heat and electricity generation in CHP or upgrading the biogas to biomethane for grid injection or BioCNG. In addition, the environmental benefits on replacing inorganic fertilisers with nutrient-rich digestate as biofertilisers for crops was also evaluated.

4.2 IRG meeting 1

The first IRG meeting was held on 11 August 2021. In this inception meeting, the various milestones of the project were discussed and the IRG members introduced to one another. The milestones, including a comprehensive literature survey for sugarcane residues and codigestion potential, techno-economic feasibility of a biogas plant along with short- and long-term impacts of the project, were presented and discussed. During this meeting, the main issue addressed was the separation of digestate into solid and liquid fractions to improve the market value of the biogas plant. In response, a decanter separation technique and an evaporator process were incorporated in the design of the biogas plant, as discussed above. Feedstock storage options were also discussed. Building a concrete silo was considered the best option as it was convenient for loading and unloading the feedstock and would prevent rotting of feedstock due to weather.

4.3 IRG meeting 2

The second IRG meeting was held on 8 September 2021. Project progress and important changes to methodology were discussed. At this stage, the IRG members were approved by the RACE Program Leader, completing the IRG establishment milestone. Results from the preliminary biochemical methane potential (BMP) experiments for the selected sugar mill and other substrates were presented to the IRG members and future BMP codigestion experiments were planned for the next phase. From the selected nine substrates, sugarcane bagasse, mill mud, food waste and chicken manure were selected for the next phase as they had the required C/N ratio for improving methane yields. A digestate hygienisation step was recommended by the IRG to meet regulatory requirements, which was incorporated in the techno-economic analysis. Transportation of liquid digestate as liquid fertiliser for crop production in Mareeba was discussed. However, due to low nutrient content in the liquid fertiliser and the economic analyses showing it is not viable, the IRG recommended recycling the liquid fraction of digestate as process water to dilute the incoming feedstock. Technologies and market potential for CO_2 recovery and purification from biogas was recommended by the IRG. The market potential was 2,000 t/d of BioCO_2 with an economic value of $200/t of Bio$CO_2$. Thus, Bio$CO_2$ production was considered in the techno-economic analyses.

4.4 IRG meeting 3

The third IRG Meeting was held on 20 October 2021. During this meeting, the results of the BMP experiments, especially the codigestion experiments, were presented for discussion and a decision on the appropriate feedstocks for the large-scale plant were made. It was concluded that bagasse, mill mud and chicken manure will be used as major feedstocks for the full-scale biogas plant design calculations and feasibility study. In addition, the decision on inclusion of CHP in all the studied scenarios with biogas upgrading for BioRNG and BioCNG production was also made as the economics on the purchase of fossil fuel electricity for biogas upgrading and the associated GHG emissions were too high. Thus, 80% of the heat produced in the CHP will be recycled to the biogas plant to reduce the dependency on LPG for heating. Techno-economic evaluation of evaporating liquid fraction of digestate to decrease the volume of digestate (by 90%) and consequently increase the nutrient content by 10% was carried out and presented to the IRG members. As the ROI on the use of evaporation for production and sale of liquid fertiliser was poor, the option for digestate treatment was ruled out. However, it was included in the final techno-economic analysis for comparison purposes. As per the IRG recommendation, the feasibility scenarios were reduced to three— (1) CHP + electricity, (2) CHP + BioCNG, and (3) CHP + BioRNG. In all scenarios, sale of solid digestate only was considered.

4.5 IRG meeting 4

The final IRG meeting was held on 23 March 2022. In this meeting, detailed techno-economic analyses of the project results were presented and some valuable suggestions from the IRG regarding some economic factors were considered. Mark Jonker (Helmont Energy) attended this meeting (substituting Roger Pattinson). He suggested that biomethane can be a good feedstock for hydrogen production and that we calculate the required hydrogen price at which biomethane can be sold for hydrogen production to make it economic. Therefore, it can also include the evaluability of biomethane in terms of hydrogen production. However, Rajinder Singh pointed out an important suggestion; that we must consider peak load demand when calculating electricity requirements in the calculations. In this case, biogas can be stored and supplied in case of higher requirements during peak load. Lisa Randone enquired if the ratio of components in the resulting digestate would meet standard regulatory requirements. However, there is no specific regulations for digestate components, but they only have restrictions for treating pathogens. Also discussed were the importance of ACCUs from full carbon calculations and their role in calculating GHG emissions from fossil fuel substitution, synthetic fertiliser production and application, and carbon sequestration in soil. The IRG recommended that we include ACCUs in revenue streams and for financial calculations. Jarrod Leak suggested we include the price for firmed electricity in peak hours as $50/MWh and for unfirmed $30/MWh. Finally, it was suggested by the IRG to carry out sensitivity analyses on plant capacity versus ROI as scaling of plant capacity tends to improve ROI and thus has a great potential to be incorporated in future bioenergy sectors for agricultural residues. Similar discussion around the cost of upgrading biogas into methane was also discussed and the IRG recommended that appropriate plant size and factors be used in sensitivity analyses as the size of the plant does not have a linear relation with CapEx. An appropriate sensitivity analysis was therefore included.

Appendix A

Equipment list, costing and parasitic loading for the studied scenarios

Equipment	Quantity	Specification	Scenario 1 CHP + electricity Cost	Scenario 1 CHP + electricity Parasitic demand	Scenario 2 CHP + BioCNG Cost	Scenario 2 CHP + BioCNG Parasitic demand	Scenario 3 CHP + BioRNG Cost	Scenario 3 CHP + BioRNG Parasitic demand
			(A$)	(kWh/d)	(A$)	(kWh/d)	(A$)	(kWh/d)
Biomass processing & storage								
Concrete bunker for biomass storage	1.0		1,600,000	–	1,600,000	–	1,600,000	–
Macerator	3.0	18.8 m^3/h	32,481	105.8	32,481	105.8	32,481	105.8
Feed pump	3.0	52.1 m^3/h	19,620	104.4	19,620	104.4	19,620	104.4
Buffer tank	2.0	350 m^3 10 m (D) × 4.5 m (H)	2,122,281	–	2,122,281	–	2,122,281	–
Biogas reactor & ancillaries								
CSTR tank	3.0	6,000 m^3 30.7 m (D) × 8 m (H)	2,122,281	–	2,122,281	–	2,122,281	–
CSTR insulation	3.0	–	8,750	–	8,750	–	8,750	–
Biogas dome	3.0	2,850 m^3 – ¼ sphere	519,000	–	519,000	–	519,000	–
Bullseye	3.0	–	2,400	–	2,400	–	2,400	–
Heat exchanger	3.0	–	24,000	–	24,000	–	24,000	–
Heat exchanger temp. sensor	3.0	–	450	4.8	450	4.8	450	4.8
Hot water transfer line 25 m	6.0	–	6,000	–	6,000	–	6,000	–
Tank pH meter	3.0	–	19,500	4.8	19,500	4.8	19,500	4.8
Temperature sensor	3.0	–	450	4.8	450	4.8	450	4.8
Pressure vacuum relief valve	3.0	–	6,300	–	6,300	–	6,300	–
Ultrasonic level sensor	3.0	–	8,100	4.8	8,100	4.8	8,100	4.8

Equipment	Quantity	Specification	Scenario 1 CHP + electricity Cost	Scenario 1 CHP + electricity Parasitic demand	Scenario 2 CHP + BioCNG Cost	Scenario 2 CHP + BioCNG Parasitic demand	Scenario 3 CHP + BioRNG Cost	Scenario 3 CHP + BioRNG Parasitic demand
			(A$)	(kWh/d)	(A$)	(kWh/d)	(A$)	(kWh/d)
DN150 manual butterfly drain valve	3.0	–	900	–	900	–	900	–
DN50 manual butterfly sample valve	3.0	–	660	–	660	–	660	–
Agitator	9.0	52,471.3 m^3/h	367,201	1,976.4	367,201	1,976.4	367,201	1,976.4
Hot water transfer pump	1.0	–	6,540	–	6,540	–	6,540	–
Manual valves	24.0	–	19,200	–	19,200	–	19,200	–
Pneumatic valves	6.0	–	39,000	–	39,000	–	39,000	–
Manual valves	24.0	–	8,400	–	8,400	–	8,400	–
Pneumatic valves	6.0	–	21,000	–	21,000	–	21,000	–
Biogas train								
Flare	1.0	539.5 m^3/h	137,772	8.64	137,772	8.64	137,772	8.64
Biogas sensor	1.0		13,756	–	13,756	–	13,756	–
Desulphur unit	1.0		5,700	–	5,700	–	5,700	–
Biogas blower	1.0	1,060.9 m^3/h	58,650	1,176	58,650	1,176	58,650	1,176
Biogas utilisation								
Biogas upgrading (cleaning and compression for grid injection)	1.0	1,060.9 m^3/h	–	–	–	–	2,937,600	4,032
Biogas upgrading (cleaning and compression for grid injection)	1.0	750 m^3/h raw biogas	–	–	2,937,600	4560	–	–
BioCO_2 recovery and liquefaction	1.0	350 m^3/h raw biogas	–	–	951,808	2,016	951,808	2,016
CHP	2.0	1,200 kW	1,861,746	–	–	–	–	–
CHP	1.0	850 kW	–	–	920,000	–	920,000	–
Electrical			209,470	72	209,470	72	209,470	72

Equipment	Quantity	Specification	Scenario 1 CHP + electricity Cost	Scenario 1 CHP + electricity Parasitic demand	Scenario 2 CHP + BioCNG Cost	Scenario 2 CHP + BioCNG Parasitic demand	Scenario 3 CHP + BioRNG Cost	Scenario 3 CHP + BioRNG Parasitic demand
			(A$)	(kWh/d)	(A$)	(kWh/d)	(A$)	(kWh/d)
Infrastructure								
Civil works			2,937,600		2,937,600		2,937,600	
Concrete works			951,808		951,808		951,808	
Roads			1,129,470		1,129,470		1,129,470	
Piping transfers			1,595,000		1,595,000		1,595,000	
Powerlines			741,000		741,000		741,000	
Balance of plant								
Electrical supply	1.0	–	50,000	–	50,000	–	50,000	–
Site survey	1.0	–	5,000	–	5,000	–	5,000	–
Structural supply—sheds	1.0	–	30,000	–	30,000	–	30,000	–
Control system	1.0	–	195,310	–	195,310	–	195,310	–
Low voltage works, earthing grid	1.0	–	129,800	–	129,800	–	129,800	–
Structures		–	253,015	–	253,015	–	253,015	–
Piping		–	285,515	–	285,515	–	285,515	–
Electrical supply		–	209,470	72.0	209,470	72.0	209,470	72.0
Soil testing	1.0	–	12,000	–	12,000	–	12,000	–
Post-storage tank								
Substrate/digestate pump	1.0	156.2 m³/h	5,000	68.4	5,000	68.4	5,000	68.4
Liquid digestate pump	1.0	48.3 m³/h	8,100	44.2	8,100	44.2	8,100	44.2
Digestate tank	1.0	10,000m³ 18.5 m (D) × 9.3 m (H)	194,649	–	194,649	–	194,649	–
Decanter centrifuge	3.0	48.3 m³/h	741,000	790.3	741,000	790.3	741,000	790.3
Electric heat exchanger	1.0	750 kW	–	–	131,000	17,280	–	–

			Scenario 1 CHP + electricity		Scenario 2 CHP + BioCNG		Scenario 3 CHP + BioRNG	
Equipment	**Quantity**	**Specification**	**Cost**	**Parasitic demand**	**Cost**	**Parasitic demand**	**Cost**	**Parasitic demand**
			(A$)	(kWh/d)	(A$)	(kWh/d)	(A$)	(kWh/d)
Pasteurisation unit	2.0	6 m^3/h	1,595,000	4,250.4	1,595,000	4,250.40	1,595,000	4,250.40
Grand total			**10,818,365**	**8,615.8**	**13,766,027**	**15,191.8**	**12,888,427**	**14,663.8**

Appendix B

Scheduling of cashflow for the studied scenarios

	Scenario 1	Scenario 2	Scenario 3
Total Capital Investment	$ 20,432,284	$ 24,953,997	$ 23,607,759
Net Yearly Profit	$ 978,823	$ 2,617,797	$ 1,579,650
ROI 1	4.8%	10.5%	6.7%
Cashflow- year 1	-$ 20,432,284	-$ 24,953,997	-$ 23,607,759
Cashflow- year 2	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 3	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 4	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 5	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 6	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 7	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 8	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 9	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 10	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 11	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 12	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 13	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 14	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 15	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 16	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 17	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 18	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 19	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 20	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 21	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 22	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 23	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 24	$ 978,823	$ 2,617,797	$ 1,579,650
Cashflow- year 25	$ 978,823	$ 2,617,797	$ 1,579,650
NPV - 25 years	-$10,579,827.43	-$1,303,418.76	-$8,559,099.09
IRR	1.1%	9.2%	4.2%

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