THE FUTURE OF BIOGAS IN WASTEWATER TREATMENT

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ABSTRACT (500 WORDS MAXIMUM)

As the water sector focusses increasingly on Net Zero strategies, there is a greater impetus on the best use of resources available at wastewater treatment plants. Biogas is generated from recovered waste and is considered a renewable energy source. There is growing interest in biogas, believed to be an essential fuel in the transition away from the world's reliance on fossil fuels. Improvements in biogas treatment technologies, new types of fuels and the desire to decarbonise are aspects that require consideration in the path forward for Watercare.

Many treatment plants in Aotearoa generate biogas through anaerobic digestion (AD), and then use this for heating and generating electricity. But as the electricity supply in Aotearoa is increasingly decarbonised, the benefit in terms of greenhouse gas (GHG) emissions reduction is rapidly diminishing. This paradoxical problem has led Watercare to consider: What is the best use of their biogas resource into the future?

Watercare produces biogas through the anaerobic digestion of collected solids at its most significant wastewater treatment sites at Māngere and Rosedale. The biogas is collected and combusted using combined heat and power (CHP) co-generation engines to produce heat and power for the treatment works as well as to minimise GHG emissions by combusting rather than emitting methane. Some biogas is also combusted in hot water boilers to provide additional process heat. As a result, biogas is a valued resource in lowering power costs and reducing the reliance on imported fuel and energy.

Watercare has set ambitious greenhouse gas reduction targets, including a 50% reduction in operational emissions (equivalent to carbon savings of approx. 70,000 tCO_2e/year) by 2030. Through Watercare's Decarbonisation Roadmap it was identified that there is the potential to achieve higher GHG emissions reduction by using some or all of the biogas produced at Māngere and Rosedale for alternative uses than the current co-gen engines to generate electricity and heat, such as to produce biomethane, which can be injected into the gas grid in order to displace fossil natural gas with its relatively high GHG emissions.

There are a range of potential opportunities for the use of biogas from wastewater AD, that are in various stages of application around the world, including:

- biogas upgrading to biomethane for grid injection,
- generation of green hydrogen, and
- recovery of a high value carbon dioxide side-stream from the biogas upgrading.

Mott MacDonald has worked with Watercare and potential technology partners to review the required technologies, potential carbon reduction opportunities, costs and revenues, and risks to site electricity resilience of using biogas in an alternative way to business as usual. Te Ao Māori principles have been considered at the outset and have guided the discussions. This paper discusses the future use of biogas in the Aotearoa New Zealand context, the primary drivers, the required technologies, and the risks and opportunities.

KEYWORDS

Biogas, Biomethane, Methane, Hydrogen, Carbon Dioxide, Wastewater Treatment, WWTP, GHG, Greenhouse Gas, Process Emissions, CHP, Co-generation.

PRESENTER PROFILE

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1 INTRODUCTION

Advanced wastewater treatment plants (WWTP) can produce biogas (carbon dioxide and methane) through the digestion of collected solids and the process of anaerobic digestion. This biogas is often combusted using combined heat and power (CHP) engines when there is enough volume to produce process heat and power for the treatment works as well as to minimise greenhouse gas emissions. The balance of biogas can also be combusted either in hot water boilers to provide additional process heat or flared. As a result, biogas is a valued resource in lowering power costs and reducing the reliance on imported fuel and energy.

Biogas is generated from recovered waste and is considered a renewable energy source and is excluded from the New Zealand Emissions Trading Scheme. There is growing interest in biogas, believed to be an essential fuel in the transition away from the world's reliance on fossil fuels. Improvements in biogas treatment technologies, new types of fuels and the desire to decarbonise are aspects that require consideration in the path forward for Watercare.

Through Watercare's Decarbonisation Roadmap it was identified that there is the potential to achieve higher greenhouse gas (GHG) emissions reduction by using some or all of the biogas produced at Māngere and Rosedale wastewater treatment sites for alternative uses, such as producing biomethane or renewable natural gas which can be injected into the gas grid. This is because electricity in New Zealand (NZ) has a low GHG emissions profile, which is projected to reduce even further in the years to come, whereas fossil natural gas in the grid will still have relatively high GHG emissions. Hence, displacing natural gas in the grid with biomethane would have a greater overall carbon reduction impact than use in CHP engines. This paper looks at those options and whether this solution could help Watercare on its way to achieving its 50% reduction target by 2030.

2 BACKGROUND

2.1 PROJECT OBJECTIVES AND APPROACH

During the establishment of Watercare's Decarbonisation Roadmap the concept of upgrading biogas to biomethane was identified. At the highest level of assessment this suggested that this project could save between 9,000 and 34,000 tCO_2e, the single largest emissions reduction project identified. An options analysis into the possible uses of biogas was agreed as one of the top four priorities for the Decarbonisation Roadmap in FY23. An application into the internal Innovation Fund for a Future use of Biogas study was successful.

There were a number of key outcomes that needed to be answered through the study. Ultimately the current biogas practices on its sites needed to be reviewed and compared with new opportunities. The review had to consider four key themes that were critical to understand for Watercare.

1. What are the needed technologies and potential operating procedures for utilising biogas in an alternative way to business as usual (BAU),
2. What are the potential partnerships/commercial arrangements and impacts on costs/revenue,
3. What is the potential carbon reduction and how this can be recognised, and
4. What are the site electricity resilience and overall risk considerations.

Mott MacDonald was selected to complete the options analysis based on their knowledge of Watercare's wastewater operations as well as expertise in similar projects internationally.

The study also engaged with a number of external parties to achieve the most in-depth level of assessment possible whilst recognizing that it was an early options analysis. Additionally, such a project has never been completed in the wastewater sector in New Zealand. Watercare were therefore interested in engaging early with the gas sector to build relationships and get a better understanding of an industry that was not familiar to them. Representatives from the following organisations were involved in the project – FirstGas, Nova, Vector, Hiringa Energy, Certified Energy NZ, Are Ake, Energy Efficiency and Conservation Authority and EcoGas. As well as these external partners a Te Ao Māori specialist was part of the team to consult on any potential impacts or opportunities that would require further consideration.

The project approach included:

- Basis of review,

- Long list of options,
- Workshop with internal stakeholders (external parties included as observers),
- Short list of options,
- Workshop with internal stakeholders (external parties included as observers),
- Feasibility report, and
- Internal and External presentation of results.

2.2 THE WWTP IN BRIEF

2.2.1 State of the process

Currently at both Rosedale and Māngere CHP engines provide electricity and process heat (the hot engine jacket water is used to heat sludge in the digesters). Biogas pre-treatment comprises particulate scrubbers, gas driers, H_2S scrubbers, and siloxane filters. The CHP engines provide 50 – 60% of the WWTP electricity demand with the balance supplied by the network. Excess biogas is flared. When the CHP engines are not operating, all electricity is supplied from the power grid and a standby hot water boiler provides heat for the digesters. Each WWTP has a standby diesel generator which is primarily used to black start the co-gen engines following a power failure. Table 1 summarises the existing assets.

Māngere does not currently have any biogas storage. Biogas storage is often useful for smoothing peaks and troughs in biogas production and ensuring a consistent biogas feed to CHP engines or boilers. Currently the process variability is managed through flaring of surplus biogas production and using natural gas when there is insufficient biogas production. Rosedale has a small amount of biogas storage under the floating digester roofs, equivalent to just over 3 hours storage at current average biogas production.

Rosedale WWTP also has a 1 MW floating solar array, installed in 2020. Its annual average output is about 1,400 MWh/year. Combining this output with that of the CHP engine, Rosedale WWTP is nearly energy neutral.

Table 1: Existing biogas, digester heating and power generation assets

Asset type	Māngere	Rosedale
Co-generation (CHP) engines	4 no. engines, each 1.7 MWe 90% availability/uptime	1 no. engine, 1.2 MWe 80% availability/uptime
Boilers	1 no. dual fuel (biogas and natural gas) hot water boiler, 3,200 kW thermal (using biogas) or 3,500 kW (using natural gas), providing heat on a standby basis	1 no. dual fuel (biogas and diesel) hot water boiler, 500 kW thermal, providing heat on a standby basis.
Biogas storage	None	1,500 Nm^3
Biogas treatment	1 no. particulate scrubber 1 no. gas drier 2 no. H_2S removal vessels 2 no. siloxane filters	1 no. particulate filter 1 no. gas drier 1 no H_2S scrubber 2 no. siloxane filters
Waste gas burner	1 no.	1 no.

Asset type	Māngere	Rosedale
Standby generator	1 no., 50kWe standby diesel generator	1 no. 500kWe standby diesel generator
Other power generation	None	1MW floating solar array, installed in 2020 (annual average output 1,400 MWh/year)

2.2.2 Forecast biogas production

A planning horizon for the investigation was set to 2048 and required to consider any expected upgrades. During that horizon both treatment plants have plans to upgrade the sludge pre-treatment process with the addition of thermal hydrolysis process (THP) for the anaerobic digesters (a form of advanced anaerobic digestion, AAD).

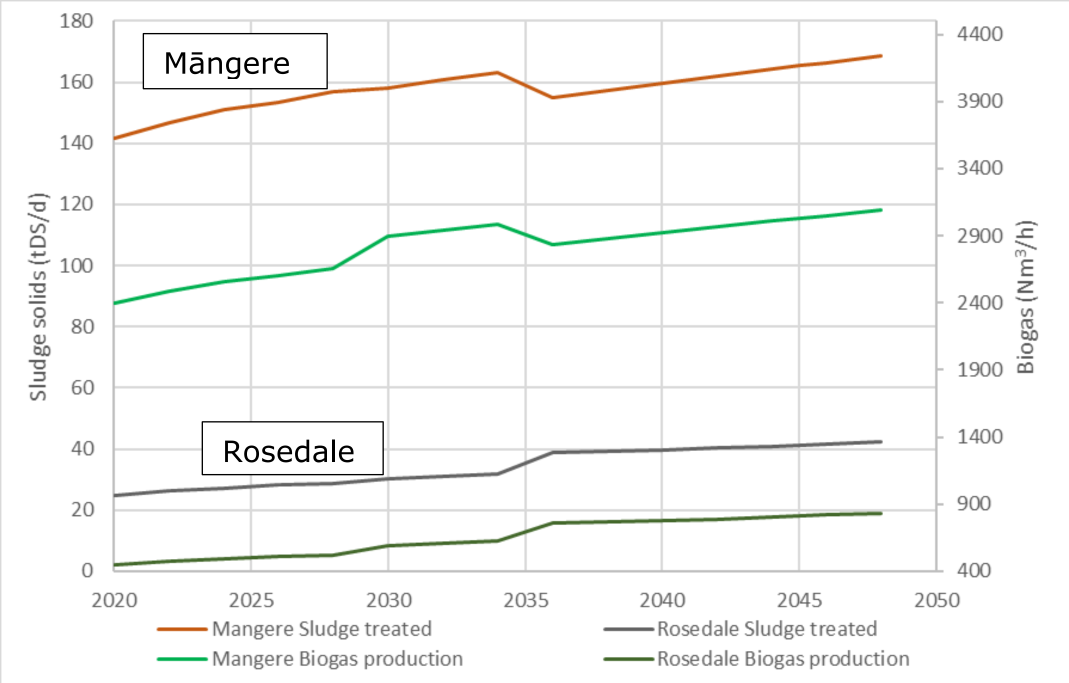
Implementation of the THP plant is expected to bring several operational benefits including:

- Increases in overall sludge treatment capacity and efficiency,
- Enhanced volatile solids destruction – with a corresponding increase in biogas generation, and
- An enhanced quality biosolids product.

The future THP uses high-pressure steam, increasing the energy demand of the plant. However, this will be offset by the higher biogas production.

Biogas production was forecast to the study horizon for each plant, taking into account future improvements to the process. Regional biosolids and co-digestion were considered as options for further increasing biogas production but were not part of the central assessment.

Figure 1: Business as Usual Biogas production forecasts – Māngere and Rosedale WWTP



Source: Graph produced using data provided by Watercare

The composition of the biogas produced at both WWTP's is broadly similar. Somewhat elevated oxygen levels were present in the biogas, which is suspected to be due to air injection upstream of biogas treatment. Raw and treated values for the biogas are shown in Table 2.

Table 2: Biogas composition and properties

Property	Units	Raw Range	Raw Typical values	Treated (Engine specification)
Relative humidity	%	100		Less than 60%
Temperature	°C	25 to 37		20 to 30
Pressure	kPa	1 to 2.5		20 (at engines) 60 to 90 (in conveyance piping)
Methane	%v/v	55 to 66	59	
Carbon dioxide	%v/v	34 to 40	39	
Nitrogen	%v/v	1.7 to 4.5	1.3	
Oxygen	%v/v	0.7 to 1.7	0.7	
Hydrogen sulphide	ppm	500 to 1,200 (Max 3,000)		80 to 300
Total siloxanes	mg/Nm³		60	8
Particulates	mg/L	0.6 to 2.5		0.9 with a size >2.5 μm
Higher heating value	MJ/Nm³		23.4	
Lower heating value	MJ/Nm³		21.1	

The biogas properties when upgraded to biomethane from both WWTP are predicted to be compatible with NZS 5442 Specification for reticulated natural gas. The potential at Māngere is for nearly 15% of Auckland’s residential natural gas demand to be met by biogas production.

2.3 CURRENT BEST PRACTICE

2.3.1 Biogas and biomethane

Current best practice biogas use in New Zealand is the use of CHP engines to combust biogas efficiently and recover energy, commonly with minimal storage. Flaring is often used to mitigate process variations, which has significant greenhouse gas emissions both through the carbon dioxide and incomplete combustion of methane. The carbon dioxide from flaring is not included within an organisation’s reporting boundary for Scope 1 emissions due to its biogenic origin.

Globally cogeneration remains the predominate solution with an emerging alternative of biomethane production being adopted in Europe, the US, UK, and Australia (Timing, J 2021). Numerous biomethane projects have been installed in the UK (at both waste AD and wastewater AD plants) encouraged by renewable gas incentive schemes. A major driver for current planned biomethane projects at wastewater AD sites are the UK water sector’s Net Zero commitments. In the Netherlands Waternet’s AGV wastewater treatment plant installed a 2050 Nm^3/h biogas upgrading plant in 2021 in parallel with the existing cogeneration, a similar scale to Māngere WWTP. Biogas upgrading via membrane separation is an established technology with limited (<1%) methane slip in the waste gas and a high concentration (95%+) of carbon dioxide. In many markets biomethane is converted into compressed natural gas for transport, which is no longer considered feasible in New Zealand.

2.3.2 CO_2 capture for utilization or sequestration

As the biogas upgrading produces a methane rich gas (biomethane) and carbon dioxide rich gas, which includes the small (approx. <1% of the total methane in biogas) methane which is not captured by the biogas upgrading plant. The carbon dioxide rich gas is normally vented as a waste off-gas but in future this could be captured and stored (carbon capture and sequestration - CCS) or used for industrial uses (carbon capture and use - CCU).

There is a present need in the NZ industrial gases market for carbon dioxide due to the closure of the Marsden Point oil refinery which previously supplied most industrial carbon dioxide. Carbon dioxide capture from the biogas upgrading plant via cryogenic separation was proposed in order to enhance the potential financial viability of the project.

In this instance feed gas would be highly concentrated from the biogas upgrading membrane process (95%+ carbon dioxide); the cryogenic process acts to purify the gas to 99%+ concentration, adequate for industrial gas use.

Reject gas from the cryogenic process; nitrogen, oxygen and methane slip, would be recirculated to the cogeneration plant for combustion and exhaust. Product carbon dioxide would be immediately transportable by tanker, simplifying logistics.

Watercare consumes a significant quantity of food grade carbon dioxide in the water treatment process and considered the export of industrial grade carbon dioxide in order to offset this consumption and generate improved commercial returns. The production of food grade carbon dioxide was not considered in the study as it was deemed that it was unlikely to be socially or culturally acceptable. More work would be required to ascertain this for certain.

Carbon dioxide capture also allows for the gas to be sequestered in geologic storage, potentially within exhausted oil or gas fields in the Taranaki. The Kapuni plant which currently produces New Zealand's domestic carbon dioxide previously used carbon dioxide injection for enhanced oil reclamation.

3 TECHNOLOGY OPTIONS

At the outset of the study the project team cast a wide net of options, including continuing existing CHP, biogas upgrading to biomethane, and subsequent conversion to hydrogen.

The longlist of options developed for the review are detailed in Table 3 as follows:

Table 3: Long list options and sub-options

Option	Primary biogas use	Primary and backup process heating sources	Approx. % of biogas available for biomethane or sale to 3rd party
1.1	Option 1: CHP engines retained	Primary: Biogas CHP engines Backup: Boilers run on biogas	0%
1.2		Primary: CHP engines run on fossil fuel Backup: Boilers run on fossil fuel	100%
2.1	Option 2: Surplus biogas converted to biomethane in plant procured and owned by Watercare	Boilers run on biogas	65% to 70%
2.2		Boilers run on biomethane	100%
2.3		Boilers run on fossil fuel	100%
2.4		Electric boilers	100%
2.5		For conventional AD only Primary: Heat pumps Backup: Boilers using biogas	90% to 100%
2.6	Combination of CHP and biomethane options – provides flexibility for variations in biomethane demand	Primary: CHP and/or /boilers Assist/standby: Boilers CHP and/or boilers sized to take biogas that cannot be exported as biomethane. Biomethane plant sized to meet max and min grid demand	40-50%
3.0	Option 3: New assets provided by 3rd party	Same sub-options as for Option 2	As for Option 2 sub-options
4.0	Offsite energy centre belonging to 3rd party	3rd party energy centre	100%

Options considered in the longlist that used fossil fuel were eliminated at the first workshop, primarily for carbon impact, while third party options were not developed further due to complexity of having an additional commercial and operational interface as well as the inability to attribute emissions reductions to Watercare.

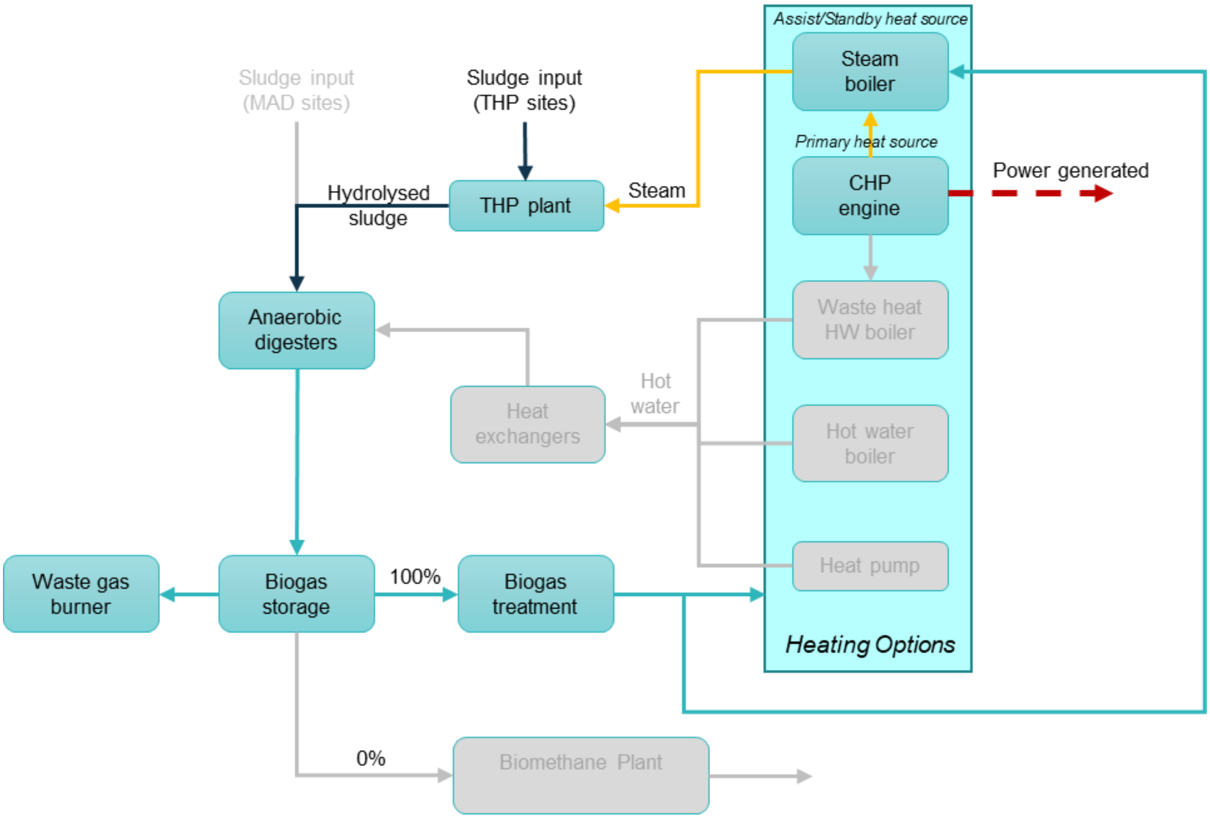
Sub-options for hydrogen and carbon dioxide capture were considered as part of the development of the shortlisted cogeneration (option 1.1) and biogas upgrading options (2.1, 2.2, 2.6).

3.1 COGENERATION

For option 1.1 (biogas fuelled CHP engines) the existing CHP engine plant at each site would be retained or repowered with new engines at end of life, potentially to coincide with THP process adoption. Replacement engine capacities would be selected to match future biogas production and provide similar or improved operational resilience to the current installations.

For this option most, if not all, of the biogas produced by the AD/AAD processes would be used for generating combined heat and power and none would be available for alternative uses.

Figure 2: Option 1.1 Process Block Diagram (with future full THP plant)



Note: the greyed-out components in Figure 2 are not applicable to this option.

The cogeneration options (1.1 and 2.6) proposed are an improvement on the current business as usual, with the provision of additional biogas storage which would be required in order to maintain power resilience and minimise natural gas use in CHP engines at Māngere (reducing opex and operational carbon emissions). This storage while critical would be limited by the operational desire to avoid operating a Major Hazard Facility.

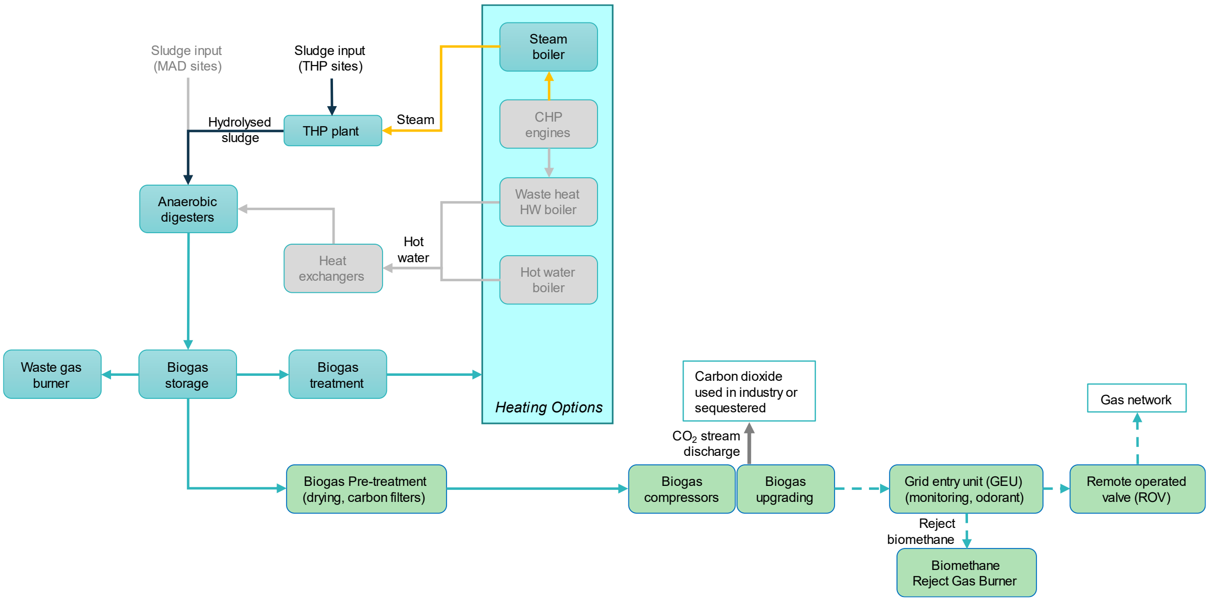
Cogeneration also forms part of the hybrid option 2.6 which utilises the cogeneration plant for power and heat production at time when the gas network is unable to accept the full biogas upgrading plant output.

3.2 BIOGAS UPGRADING

3.2.1 Biomethane production

For options 2.1 and 2.2, biogas produced by the AD or (future) AAD processes is stored, treated and sent in part or entirely to a biogas upgrading plant where CO_2 and other impurities are largely removed in order to produce a 'biomethane' product (which is >97% methane). The biomethane product would be injected into the local gas network. Any biomethane product that did not comply with the required network gas quality would need to be flared.

Figure 3: Option 2.1 Process Block Diagram (with future THP plant)



Note: the greyed-out components in Figure 3 are not applicable to this option.

Biomethane composition would be compliant with NZS 5442, the specification for reticulated natural gas in New Zealand, when produced via membrane separation. Membrane separation is well proven in WWTP biogas upgrading processes, and have a wide operating range with typical supplier proposals guaranteeing operation turn-down to 30% of the design capacity of the plant. Furthermore, membrane type biogas upgrading plants, which contain multiple membrane filter cartridges, can be designed to have fewer cartridges in the earlier years of operation, thus reducing initial capex, with additional cartridges installed in later years as flows increase.

The year 2048 biomethane potential for Māngere is approximately 1500 Sm^3/hr while at Rosedale 500 Sm^3/hr, nominally 33-23% of biogas produced at each site is consumed for process heat. At the 2048 throughputs the plants would be considered very large and medium in size respectively, although with current biogas production volumes Rosedale would be considered a small plant for biogas upgrading.

Storage remains a critical feature of biogas upgrading options in order to ensure minimum throughputs to the upgrading unit throughout the daily and seasonal process variations.

The full biomethane production options (2.1/2.2) rely on the gas network and another off taker (e.g. hydrogen) absorbing the full throughput of the WWTP to achieve the calculated carbon abatement. Table 4 shows the limitations of the gas network which would be exceeded by 2024 biomethane production at minimum. Debottlenecking the supply of biomethane to the Auckland grid would likely require additional capital in order to permit full export at all times to the higher pressure network.

Table 4: Gas network connection points and available capacity

Site	Weekday / Winter Average demand (Sm^3/hr)	Weekend/ Summer Minimum Demand (Sm^3/hr)
Māngere	1,050	500
Rosedale	500 (Winter)	150 (Summer)

Note: MP7 = medium pressure, 7 bar, MP4 = Medium pressure, 4 bar

Under Option 2.6, use of each asset would vary according to biomethane use and remaining biogas quantities, as follows:

- Periods of **maximum** biomethane demand from the grid – remaining biogas would be mostly used in boilers to produce process heat, as there would be insufficient biogas to generate sufficient heat using CHP engines alone
- Periods of **minimum** biomethane demand from the grid – remaining biogas would be mostly used in CHP engines, which would produce sufficient heat for the AD process (conventional or with THP plant) and power for the site

For this hybrid option 46-74% of biogas is consumed for use in cogeneration.

3.2.2 Carbon dioxide capture

Sale of carbon dioxide for industrial purposes (CCU) would not only displace net carbon dioxide obtained from fossil fuels but create a potentially significant additional source of income.

Thus, purification of carbon dioxide rich waste gas from the biomethane production is particularly important to the commerciality of biogas upgrading in New Zealand in the short term. Māngere could potentially produce between 14 to 29 tonnes of carbon dioxide per day, approximately 30% of typical Kapuni production. Noting that current abnormally high prices are likely to regress to the mean as the Kapuni plant returns to service and full production, the adoption of this option for biogas upgrading was contingent on further market and commercial analysis.

Due to Te Ao Māori considerations, it was found appropriate for industrial use only and the suitability of food grade use was not further explored. Wider cultural acceptability such as halal, kosher, etc. were not considered in this project.

3.2.3 Hydrogen production

As an alternative to export to the gas network, hydrogen production via steam methane reformation was considered. This sub-option, while technically viable and offering a higher overall carbon abatement by displacing diesel use, had higher capital costs and expected future downward pressure on hydrogen prices. This option was not explored further but could be added on at a future point.

4 EVALUATION

4.1 MULTI CRITERIA ANALYSIS SCORING

A multi-criteria assessment (MCA) workshop was held with Watercare and the project partners, using the following criteria:

- The maturity of technology, particularly track record in the NZ market,
- Commercial impacts and benefits to Watercare,
- Total Carbon savings, both indirect and direct,
- Te Ao Māori outcomes – are the potential outcomes enhancing or degrading in a Te Ao Māori approach,
- Marginal abatement cost of emissions reduction – how cost effective is the carbon abatement,
- Ability of Watercare to recognise (direct) emissions reduction – can Watercare account and recognise the emissions reduction against scope 1 and 2,
- Health and Safety impacts – are there additional hazards and risks associated with the option, potential to be a major hazard facility, more compressed gases on site etc.,
- Additional operational complexity – does the option increase the number of "moving parts" to operating the WWTP,
- Potential environmental impacts from emissions, traffic, odour, noise, etc – does the option have significantly more heavy vehicle movements per day, are there additional emissions or noise,
- The flexibility / scalability of the option and ability to be staged – a least regrets decision with the facility to pivot – does the option commit Watercare to a long-term market (gas to grid / hydrogen production / CO_2 production) or be flexible and allow the plant to cope with growth / changes in process,
- The impact of the option upon plant resilience – does this option increase or decrease the reliance of the WWTP upon the electrical/gas grid vs BAU,
- The impact of the options constructability – impact of land take, space, additional infrastructure requirements.

In assessing the options for both WWTP it was apparent from the scoring that option 1.1 (cogeneration) and option 2.6 (hybrid of cogeneration and biomethane to grid) were preferred. Broadly the evaluation found that:

- Technology maturity of both options rated highly, with only the addition of carbon dioxide gas capture (liquefaction) as a moderate value due to the additional process,
- Commercially the existing cogeneration system was optimal with the hybrid cogeneration and minimal biogas upgrading (2.6), carbon dioxide capture was a significantly positive addition to biomethane options, however future carbon price uncertainty was identified as a commercial risk for further evaluation,
- If it was possible to export all of the biomethane to the grid (without the network constraints) it would have made the projects financially viable provided long term industrial gas prices remained high,
- Biomethane options have the most significant carbon savings through displacing other gas consumers' emissions,
- Full biomethane production was considered most enhancing from a Te Ao Māori perspective,
- The marginal abatement cost for full biomethane options was lowest and competitive with the expected price of carbon, however for Rosedale all options were non-competitive with the price of carbon due to the lack of scale and uncertainty with the future price pathway for carbon,
- Watercare is not able to recognise emissions reduction under scope 1 and 2 for exported biomethane to the gas network, reducing the value to the organisation of option 2.1/2.2. Despite higher net carbon reduction these options would increase electrical grid demand for Watercare,
- Health and Safety impacts of each option were considered broadly similar to current operations with only full biogas upgrading potentially requiring Major Hazard Facility consideration,
- Cogeneration introduces no additional operational complexity while a hybrid of cogeneration with biomethane production was considered a significant increase in complexity,
- Potential environmental impacts only increased for biomethane, particularly with carbon dioxide capture due to change in land use, visual impact of additional plant and traffic movements,
- The flexibility / scalability of the hybrid cogen option was greatest with the ability to adapt to changing market conditions as engines required replacement and increase capacity if needed. Cogeneration (1.1) scored positively while the pure biomethane options (2.1/2.2) committed Watercare to biomethane production, with some flexibility to scale up over time,
- Plant resilience was not significantly impacted by any option as biogas remains available to provide process heating; the limited biogas storage might provide some short term outage support for cogeneration options but the WWTP continue to rely on the electrical grid,
- The cogeneration options' constructability was far superior as the existing plant could be repowered in the case of Māngere and Rosedale. Biomethane with carbon dioxide plants' constructability may be a challenge at Rosedale, while there is sufficient space at Māngere.

While the above may not be directly applicable to all WWTP within New Zealand the general findings are likely to be indicative of probable solutions.

Noting that the "debottlenecking" of biomethane supply to the gas network would require further capital expenditure, this was not considered viable as this would have a further deleterious impact on the challenging commercial outcomes for option 2.1 and 2.2 even with the benefit of carbon dioxide production.

4.2 TE AO MĀORI

This project consulted with the services of Dallas King to provide input and insights from her expertise with a focus on Te Ao Māori perspectives, limitations and opportunities. Through this process a number of wānanga (meetings and discussions of experts) were had with other experts to provide input to the project. The perspectives that were provided are one interpretation and were given in the context of the Watercare options assessment, and should not be extrapolated to be an overall opinion for biogas.

The wānanga felt that although this project is about best use of gas, it is valuable to keep the connection to water in the narrative and links to removing paru (dirt, sewage) from water, as this adds a lot of mana (integrity, power).

At the outset of this project a concern was raised as to whether there would be any tapu (prohibition, restriction) around the use of biomethane in cooking, which could potentially restrict injection of biomethane into the natural gas grid.

The wānanga found that the use of gas that is produced through the process of treating human excrement in the production of food (such as carbonated drinks) is not culturally accepted in Te Ao Māori whereas it is acceptable to use it for heating or where it will go to flame. For it to be free of restrictions it must first be combusted. In this respect biomethane would be acceptable because it would be combusted. Use of carbon dioxide in food production, including water treatment, on the other hand, would be considered tapu. The use of carbon dioxide in industry for processes other than food production, however, would likely be acceptable.

Separation (e.g. filtration) is not same as combustion and does not remove the paru. This was likened to a nutritionist convincing a practicing Judaist of the nutritional value of pork. It is a belief system that tells them it is an unclean meat.

The wānanga concluded that the gas must change form and combustion is the only way they know where this would happen. The understanding of combustion is that it is heated to a point where it is transformed into another form. There is room for debate around what this might look like. For example, if processing of the gas or the sludge using high temperature and pressure steam may be considered tantamount to combustion then this is something that should be discussed. Such processes might include thermal hydrolysis of the sludge prior to digestion, or steam methane reforming of the biomethane to produce hydrogen with carbon dioxide as a by-product. Further debate and discussion are required around this subject.

4.3 PREFERRED OPTIONS

4.3.1 Cogeneration

Cogeneration (option 1.1) scored highest across the multi-criteria analysis and remains the best use of biogas at the plants during the horizon of the project at the time of assessment.

Scalability of pure cogeneration options is achieved through high redundancy, essentially additional engines operating at low loads at the beginning of life.

In terms of carbon emissions reduction, a move to full biogas consumption would improve performance at Māngere as some cogeneration with natural gas is currently used.

Table 5: Cogen GHG emissions (tCO_2e/y)

	Units	Māngere			Rosedale		
Year		**2024**	**2030**	**2048**	**2024**	**2030**	**2048**
Direct emissions (scope 1 and 2)							
Methane slippage, biomethane plant	tCO_2e/y	0	0	0	0	0	0
CHP (Nox etc)	tCO_2e/y	29	31	35	5	6	9
Indirect emissions							
Power generated – offsetting grid power	tCO_2e/y	-4,921	-5,162	-5,906	-842	-930	-1,482
Power consumption – additional	tCO_2e/y	0	0	0	0	0	0
Natural gas emissions saved	tCO_2e/y	0	0	0	0	0	0
Net emissions	**tCO_2e/y**	**-4,892**	**-5,132**	**-5,871**	**-837**	**-925**	**-1,473**

It is salient to note that at the smaller Rosedale site the commercial performance of the option was poorer than expected from a best practice solution, which may be indicative of the challenges likely to be faced with smaller plants decarbonising.

Net emissions reductions are expected to further decrease from the above values as the decarbonisation of grid electricity takes place.

4.3.2 Hybrid Cogeneration with Biomethane and CO_2 capture

At Māngere the hybrid option of cogeneration and biogas upgrading (without CCU) scored second highest and for a large plant this would provide additional beneficial use for the biogas. The addition of carbon capture only dropped this option to third in the assessment, hence the flexibility of adding CCU to a later stage is considered beneficial to the base option 2.6.

This option has significant benefits in terms of scalability as the turndown in biogas upgrading plant, with the provision for future expansion allow the operator to modify the plant to adapt to changing market conditions.

Table 6: Hybrid Cogen and Biomethane GHG emissions (tCO_2e/y)

	Units	Māngere			Rosedale		
Year		**2024**	**2030**	**2048**	**2024**	**2030**	**2048**
Direct emissions							
Methane slippage, biomethane plant	tCO_2e/y	1,486	1,568	1,345	273	305	477
CHP (Nox etc)	tCO_2e/y	13	13	19	2	2	4
Indirect emissions							
Power generated – offsetting grid power	tCO_2e/y	-2,168	-2,275	-3,150	-312	-340	-593
Power consumption – additional	tCO_2e/y	879	917	879	215	251	333
Natural gas emissions saved*	tCO_2e/y	-14,654	-15,372	-14,654	-3,168	-3,531	-5,082
Net emissions	**tCO_2e/y**	**-14,444**	**-15,149**	**-15,562**	**-2,990**	**-3,313**	**-4,861**

*Note: not attributable to Scope 1 or 2 emissions for Watercare

4.3.3 Attribution of emission reductions

The study concluded that larger emissions reductions were possible from upgrading the biogas to biomethane by using it to displace natural gas by another user, than in comparison to the current BAU where grid electricity is being displaced. This is because the greenhouse gas emissions factor for natural gas is higher than electricity and in New Zealand. This difference is expected to become even larger as the electricity grid becomes more renewable and therefore less emissions intense in the coming years.

Because the proposed solutions would displace the consumption of natural gas for an external user through the natural gas grid, the question of who gets to recognise the emission reduction was raised and explored. The attribution of the carbon savings was important for Watercare to support meeting their target to reduce operational emissions by 50% by 2030.

The utilisation of renewable energy certificates and the exploration of other existing mechanisms was investigated. This is an emerging space for New Zealand and whilst renewable certificates do exist in the electricity market, they are not commonplace or yet used in other areas such as renewable gas.

Additionally, because Watercare does not have a large natural gas consumption footprint to offset against, there were limitations with the proposed approach for renewable gas certificates and the objectives of attributing the emissions reductions to Watercare.

The final result of the study concluded that whilst larger emissions reductions were possible by creating biogas instead of generating electricity, these could not be attributed to Watercare or used to meet their target as they would be reducing another user's emissions.

5 CONCLUSIONS

While a wide net was cast for the future of biogas, the particular conditions for New Zealand appear to indicate continued adoption of cogeneration for anaerobic digestion plants, potentially with hybrid options to make use of excess gas at large WWTP.

There are a number of key findings from the project, in brief:

- Financial viability of biomethane options are strongly dependent on the additional value of industrial carbon dioxide production and hence the price sensitivity of this market requires further analysis,
- The gas network limitations impose a bottleneck on biomethane options,
- Direct emissions reductions under current attribution models strongly favour cogeneration options,
- The contribution of WWTP scale is key to viability, with smaller plants with biogas production below 1,000 Nm^3/hr limited to cogeneration for carbon abatement,
- There is limited technology risk of adopting biogas upgrading even with carbon dioxide liquefaction as all processes proposed are at high technology readiness,
- Attribution of carbon reduction from cogeneration to Watercare significantly impacts the preference towards a lower total carbon reduction option, which is an issue for all NZ water utilities and the wider decarbonisation of the New Zealand economy,
- The lack of incentives in the New Zealand market for biomethane, e.g. in the form of trade-able green gas certificates and/or direct incentives for biomethane, whether injected into the grid or used as a vehicle fuel, hampers uptake.

It was estimated that, if connected to the higher pressure network, Māngere could provide nearly 15% of Auckland's residential natural gas consumption, if adequately supported and incentivised. This would allow for the existing infrastructure to continue to provide utility, and mitigate some need for additional electrification infrastructure, while supporting overall decarbonisation by continuing to supply natural gas industries that remain intractable to transition. The current attribution model does not support this.

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