Carbon Negative Geothermal: Financial Analysis for Combined Geothermal, Bioenergy and Carbon Dioxide Removal

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ABSTRACT

Coupling bioenergy with carbon capture and storage (BECCS) is a net carbon negative process that has been highlighted by the Intergovernmental Panel on Climate Change as an important technology for offsetting greenhouse gas emissions. Despite their proposed efficacy as both a power production and negative emissions tool, BECCS technologies currently lack widespread use due to their high costs. Coupling geothermal fields with BECCS operations by dissolving biogenic CO_2 in geothermal brine could reduce the transportation and injection costs by leveraging geothermal reinjection apparatus for sequestration.

Dissolved biogenic CO_2 could be stored more safely in a geothermal reservoir through pressure maintenance, sidestepping leakage concerns from storing buoyant supercritical CO_2. Additionally, geothermal and bioenergy synergize as electricity generation technologies, leading to higher utilization efficiencies.

Our analysis shows that geothermal-BECCS plants could have operational emissions intensities of -137 gCO2/kWh to -928 gCO2/kWh, offsetting 30% to 206% of the emissions from a standard natural gas plant. For the CO_2 price of NZD 80/tonne in 2022, geothermal-BECCS could have a levelized cost of electricity (LCOE) of NZD 163 to 203/MWh, cheaper than overseas standalone BECCS estimates NZD 267 to 426/tonne. For a projected CO_2 price increase of NZD 160/tonne by 2035 suggested by the Climate Change Commission, geothermal-BECCS plants could have LCOEs as low as NZD 29 to 54/MWh. This would be more competitive than geothermal plants while also removing up to 110,000 tonnes of CO_2 a year.

1. INTRODUCTION

Announced in 2022, Aotearoa's geothermal industry has put forth a unified effort to reinject magmatic-origin CO_2 emissions from geothermal power plants (Ara Ake, 2022). This could pave the way for future coupling of geothermal energy with direct air carbon capture & sequestration (DACCS), which is already deployed in Iceland (Ara Ake, 2022), and bioenergy and carbon capture and sequestration (BECCS), which presents an opportunity to boost renewable power while storing away biogenic CO_2 emissions (Titus et al., 2022).

Because biogenic CO_2 was originally absorbed from the atmosphere, both geothermal-DACCS and geothermal-BECCS (Figure 1) present an opportunity for carbon negative geothermal systems. One key difference is the theoretical ability to apply BECCS hybridization to (1) retrofit existing geothermal power stations operating below design capacity, and (2) make use of low temperature geothermal systems for electricity generation by improving utilization efficiency. 70% of the world's geothermal systems are less than 160°C (Hochstein, 1990), so improving their accessibility could strengthen the supply of a reliable, baseload source of renewable energy.

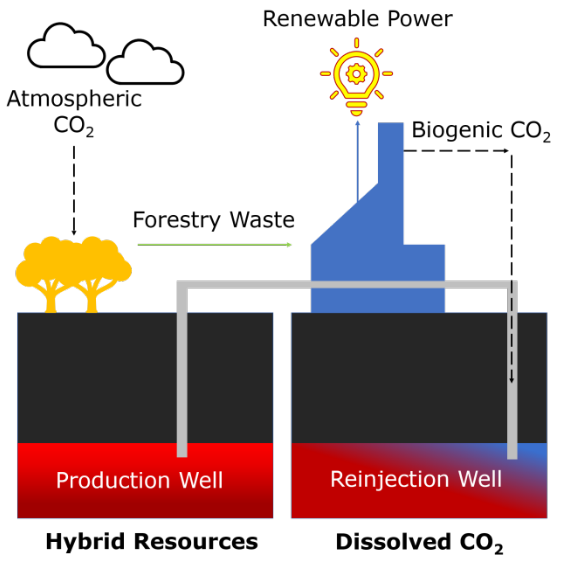


Figure 1: Process cycle schematic of a geothermal-BECCS system.

However, the thermodynamic viability and negative emissions capability of potential geothermal-BECCS power plants must be considered within the context of the wider electricity market. It is important to consider how the power generation process is financially impacted when coupled with carbon capture and storage (CCS). This paper establishes an early understanding of the economic viability of geothermal-BECCS within Aotearoa's current landscape, and provides analysis on the impact feedstock and CO_2 price trends on key financial indicators such as the levelized cost of electricity (LCOE), capital cost rate and payback period.

2. ECONOMICS OF DUAL DECARBONISATION

2.1 Energy production

Different power generation technologies can be compared using LCOE, defined as the unit cost of the electricity generation process divided by the total amount of generation in a plant's life ($/MWh), expressed in present value to account for future inflation (IRENA, 2021). LCOE should ordinarily surpass the wholesale electricity price for a project to be deemed financially successful.

Newly commissioned geothermal projects had a global weighted average LCOE of NZD 108/MWh in 2021 (IRENA, 2021). New bioenergy power projects (without CCS) in the same period had a global weighted average cost of NZD 107/MWh, though this value was brought down by countries such as India and China where available biomass feedstocks were relatively cheap (IRENA, 2021). Europe and North America had values closer to NZD 140/MWh and NZD 154/MWh respectively, highlighting the importance of accessible, low-cost feedstocks. Ideally, any potential geothermal-BECCS plant should operate at a comparable LCOE to standalone geothermal and biomass plants to be successfully implemented.

Three major costs are used to calculate LCOE: the capital expenditure of the plant (CAPEX), annual operation and maintenance expenditure (OPEX), and any fuel costs. Traditional geothermal power plants typically have high capital costs, low operational and maintenance costs, and no fuel costs (IRENA, 2021), but with some CO_2 emissions.

The CAPEX of different power plants is compared using the capital cost rate, a measure of the total CAPEX divided by the plant capacity ($/kWe). The weighted average capital cost rate for new geothermal developments in 2021 was NZD 6346/kWe and ranged from 3145/kWe to 10411/kWe (IRENA, 2021). Annual OPEX values tend to vary by plant but an estimate of NZD 183/kWe was assumed by IRENA (2021). CO_2 emissions from geothermal plants could contribute to significant costs in terms of carbon credits.

On the other hand, bioenergy projects tend to have a lower average capital cost rate than geothermal plants at NZD 3741/kWe (IRENA, 2021), but have annual OPEX values of 2 to 6% of the original CAPEX. Arguably the most significant economic parameter of bioenergy are the feedstock gate costs (sum of harvesting and transport costs to the plant).

The most competitive bioenergy projects make use of feedstocks readily available at industrial sites to lower marginal acquisition costs. Power plants based around low-cost feedstocks like agricultural and forestry residues tend to have the lower LCOEs (IRENA, 2021).

Aotearoa has several biomass feedstocks available as by-products from other commercial industries, notably forestry residues (MPI, 2020). Aotearoa's forestry industry is mostly made up of quick growing Pinus Radiata, often exported as unprocessed logs (MPI, 2020).

Forestry residues are the waste components of trees that are not used when harvesting and manufacturing solid wood products, like timber (MPI, 2020). They are expensive to transport as the energy content of wood products is lower per kilogram than coal, and thus the feasibility is dependent on local supply. Forestry waste is commonly discarded as a by-product in commercial forestry activities (MPI, 2020) but a sufficient market for it has yet to develop in Aotearoa.

Residual woody biomass was found to be uncompetitive in Aotearoa during the 2020 'Wood Fibre Futures' stage one report (MPI, 2020). At the time, it was 20% more expensive to use forestry residues in Aotearoa than in key competitor countries due to difficult terrain and transportation. Additionally, the carbon price was much lower in 2017 at NZD 25/tCO_2e, a fraction of what could be seen in large bio-economy nations in Europe and North America (>NZD 250/tCO_2e; MPI, 2022). However, as of August 2022, the carbon spot price is approximately NZD 80/tonne (CarbonNews, 2022).

Overseas, geothermal-bioenergy hybridization can be economically viable in the right context. At the Lardarello geothermal field in Italy, a biomass superheater was implemented by Enel Green Power at the Cornia-2 plant (Dal Porto et al., 2016). Previously operating below design capacity, the flash plant was retrofitted to provide steam superheating to 370°C, adding 6 MWe of power. The biomass feedstock was available from local suppliers and the retrofit project was supported by a dedicated feed-in tariff and local government incentives.

Despite being an 'infant' technology, there are a few recent examples of LCOE analysis for BECCS plants (with supercritical CCS, not in-line dissolution), serving as points of further comparison to geothermal-BECCS. One study from the UK considered forestry residues, energy crops and agricultural residues for BECCS and found that net plant efficiency decreased when coupled with CCS (Emenike et al., 2020) because it incurred an energy penalty. For a 250 MWe BECCS plant, LCOEs ranged from NZD 320 to 426/MWh depending on feedstock type and capture method.

This was notably higher than the reference bioenergy plant from NZD 196 to 245/MWh. LCOE was found to be most sensitive to fuel cost, followed by CAPEX or capacity cost (the cost to increase plant capacity), and capacity factor (Emenike et al., 2020). Another study comparing solar and wind-based DACCS to BECCS also concluded that the LCOE of BECCS was heavily tied to the price of feedstock (Lehtveer & Emanuelsson, 2021).

A study based in China that considered different configurations of bioenergy-coal co-firing found that a pure BECCS plant had an LCOE of NZD 267/MWh (Yang et al., 2021). Different permutations of co-firing decreased the LCOE to NZD 169 to 200/MWh, but this was still a sharp increase from a pure coal plant without CCS at NZD 76/MWh. The study considered plant gate costs of NZD 151/ton for biomass NZD 87/ton for coal.

2.2 Carbon dioxide removal

The market price of CO_2 has a major impact on the feasibility of biomass and BECCS projects. Unsurprisingly, the economic incentive to remove CO_2 must outweigh the costs of doing so (Galiègue & Laude, 2017). Historically, the incremental cost of capture and insufficient market incentives has made supercritical CCS difficult to implement on a wide scale in the energy sector (de Coninck et al., 2018). This means that applications of BECCS have two major hurdles to cross: (1) they must distinguish themselves from traditional supercritical CCS projects based around fossil fuels, and (2) they must compete with standard generation types in the current energy matrix, which CCS notably struggles to do (de Coninck et al., 2018; Galiègue & Laude, 2017).

A European study compared traditional CCS and BECCS for a power plant and found that a carbon tax above NZD 37/tonne was more economically favourable to BECCS (Wei et al., 2020), noting the European emission allowance at the time CO_2 price was slightly higher at NZD 38/tonne.

For the UK example mentioned in the previous subsection, the break-even price of carbon for the BECCS plant to compete with natural gas needed to be NZD 131 to

232/tonne, depending on feedstock and capture method (Emenike et al., 2020).

In-line dissolution, as pioneered at the CarbFix project in Iceland, presents an opportunity for lower cost CCS with added storage security (Galiègue & Laude, 2017; Gunnarsson et al., 2018). Furthermore, in-line dissolution can cut costs by using the existing reinjection apparatus of the geothermal instead of off-site transportation and injection. A notable disadvantage of in-line dissolution is the limits to the solubility of CO_2 in reinjectate, potentially resulting in an inability to capture all emissions

The total cost of early CO_2 (and H_2S) capture and sequestration at CarbFix totalled to NZD 31/tonne of the gas mixture (Gunnarsson et al., 2018) for scrubbing and capture, new transport infrastructure. Injection and monitoring costs were roughly NZD 3.2/tonne. Comparatively, conventional CCS can cost NZD 60 to 227/tonne of CO_2 (Gunnarsson et al., 2018), a significant increase over in-line dissolution.

3. METHODOLOGY

With the economics of power production and carbon dioxide removal (CDR) serving as a blueprint, the scope of this research was to establish an initial LCOE for two geothermal-BECCS configurations at both current and potential future market conditions in Aotearoa. This was accomplished through the development of a techno-economic systems model that could demonstrate the sensitivity of total costs, annual electricity generation, and annual sequestration to changes in the plant gate cost of forestry residues and the price of CO_2 on the Emissions Trading Scheme (ETS).

The equation for LCOE used in this study is a slight variation on the method used for traditional geothermal plants because the negative emissions of CO_2 are characterized as effective revenue while CO_2 compression and in-line dissolution are factored into the total value of costs:

$$LCOE = \frac{NPV_{\text{cost}} - NPV_{\text{rCO}_2}}{NPV_{\text{electricity}}} \tag{1}$$

Where NPV_{cost} is the net present value of all geothermal-BECCS lifecycle costs (NZD), NPV_{rCO_2} is the net present value of biogenic CO_2 revenue throughout the plant's life (NZD), and $NPV_{\text{electricity}}$ is the net present value of electricity generated throughout the plant's life (MWh). Electricity generation was calculated using thermodynamic mass and energy balances for hybrid geothermal-biomass power plants (DiPippo, 2016; Thain & DiPippo, 2015). Three key parasitic loads were included: the work of a downhole pump, the work of surface pumps, and the work to compress and deliver CO_2 to in-line dissolution conditions.

Where possible, cost correlations for plant apparatus were used because they directly scale with the thermodynamic sizing of the plant (Turton et al., 2008). In other cases, analogous values of capital cost rates were adapted from literature. Cost correlations for pumps, the turbine, the geothermal heat exchanger, the condenser, the cooling apparatus and the separator were obtained from Shamoushaki et al., (2021). The cost correlations for geothermal wells were obtained from Lukawski, et al., (2014).

Analogous values were used for the capital cost rates for boilers (Windsor Energy, 2022), in-line dissolution (Gunnarsson et al., 2018), and OPEX values for geothermal, bioenergy (IRENA, 2021) and in-line dissolution (Gunnarsson et al., 2018). Other model assumptions are presented in the Appendix. The capital cost rate (CCR) is defined simply as the CAPEX divided by the plant capacity (W_{net}) with a high contingency of 20% of CAPEX (IRENA, 2021):

$$CCR = \frac{CAPEX \times 1.2}{W_{\text{net}}} \tag{2}$$

Net cash flow (NCF) is another useful financial metric that is defined as the difference between the cumulative costs and the cumulative revenue over the operation time of a project:

$$NCF(n) = \sum_{i=1}^{n} Revenue - \sum_{i=1}^{n} Costs \tag{3}$$

Where n is the number of years that the plant has been operating. Due to upfront nature of CAPEX costs, but the cumulative nature of revenue, NCF is negative at n=1. A plant's payback period is determined by the financial year in which the NCF of a project becomes positive. If this happens prior to the plant life, then the plant will eventually be profitable. In this work, we assumed a plant life time of 30 years for geothermal fields. Although some geothermal fields like Wairakei and Ohaaki have operated for beyond 30 years, financial analysis should provide conservative estimates (IRENA, 2021). If NCF value is not expected to reach 0 by the final year of operation, then the project is unviable. In practice, NCF and payback period are sensitive to the price of electricity on the wholesale market, which will vary with time, grid response and future changes to the overall energy matrix. For this study, we assumed a fixed electricity wholesale price of NZD 90/MWh, which allows us to explore the effects of feedstock and CO_2 price. No other taxes or subsidies were considered in this work.

The costs and revenue of CO_2 were calculated as CAPEX NZD 31/tonne and OPEX NZD 3.2/tonne (Gunnarsson et al., 2018), scaled using the sequestration rate, which depends on the biomass emissions rate and the reinjection fluid's carrying capacity for CO_2 dissolution. For the solubility of CO_2 in pure water, we used the chemical potential model of Duan & Sun (2003). The price of CO_2 in 2022 is NZD 80/tonne but is recommended to rise to NZD 250/tonne by the year 2050 by the Climate Change Commission to achieve the targeted national carbon budget (MBIE 2020). Thus, for this work, the CO_2 price is projected to rise to NZD 160/tonne by 2035.

It is more challenging to delineate an exact gate cost for forestry residues due to the large variety of physical properties and supply locations. "On truck" costs are estimated to be NZD 5 to 45/m^3 (MPI, 2020). Assuming a specific density of forestry residues at 1234 kg/m^3 (Nurek et al., 2019), with transport costs NZD 35 to 89/tonne, the plant gate cost could be NZD 39 to 125/tonne, with NZD 70/tonne an approximate median scenario (high harvesting cost and low transport costs). For this study, we have assumed a conservative value of NZD 140/tonne to cover any other unexpected cost for 2022 conditions but considered the possibility of NZD 70/tonne being achievable by 2035. A benchmark ORC plant (Figure 2) was used to compare an ORC geothermal-BECCS plant (Figure 3) and a geothermal-BECCS preheat plant (Figure 4).

For the baseline configuration, a downhole pump delivers 168 kg/s of geofluid (3 wells at 56 kg/s each) to an evaporator and preheater at 18 bar from a reservoir at 160°C and 50 bar. The working fluid, isopentane (95 kg/s), is heated from 46°C to 147°C (732 kJ/kg) before passing through a turbine and condensing from 18 bar to 1.866 bar. The geofluid exit temperature is 95°C. A pure water model is used for simplicity, assuming no magmatic CO_2 or mineral presence. In Titus et al. (2022), we show that these effects are generally negligible for Aotearoa's fields.

The first geothermal-BECCS configuration (Configuration A), operates under a similar setup to the benchmark plant, except that the geofluid only preheats the isopentane to the liquid saturation curve at 525 kJ/kg (Figure 3). The remaining heat of vaporization to 732 kJ/kg is provided by a biomass boiler. This allows the plant to use more isopentane in the working fluid cycle (168 kg/s), increasing nameplate capacity. A higher heating value of 15350 kJ/kg was assumed for the forestry residue, resulting in a biomass burn

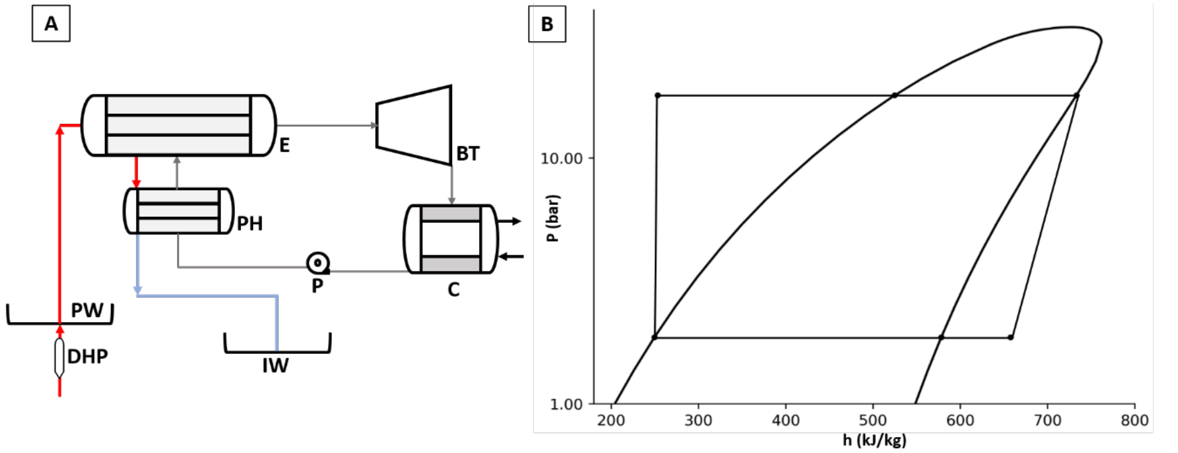
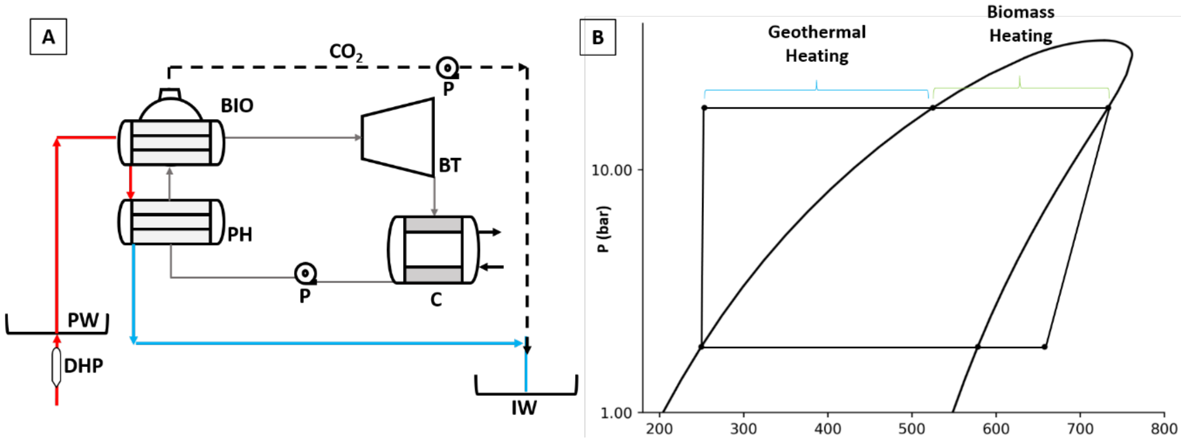


Figure 2: Schematic (A) and pressure-enthalpy (P-h) process diagram (B) for benchmark plant. DHP = downhole pump, PW = Production Well, E = evaporator, PH = preheater, BT = binary turbine, C = condenser, IW = Injection well, P = surface pump. Red-line = hot geofluid, blue-line = cold geofluid, grey-line = working fluid (isopentane).



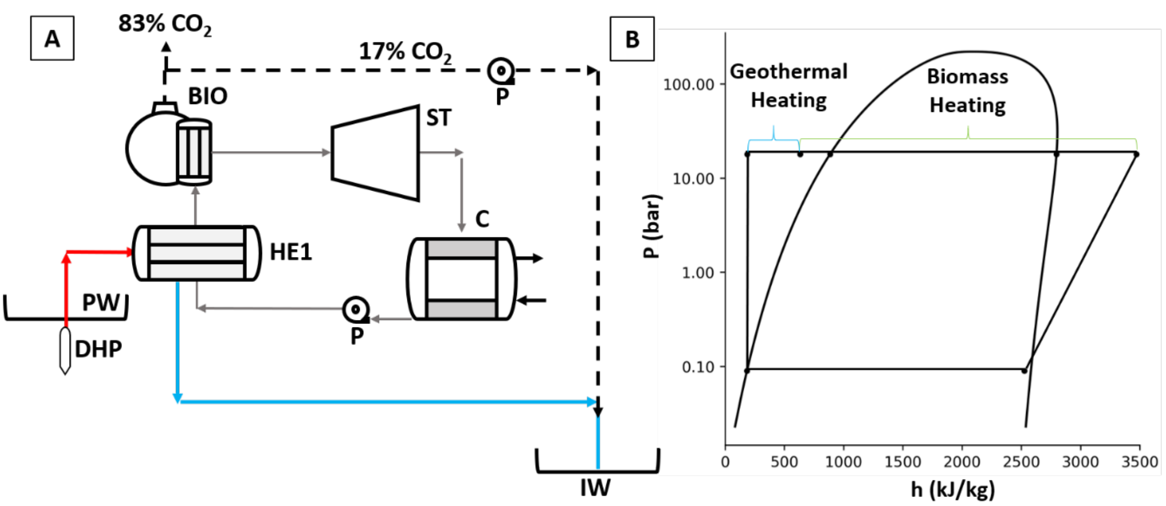


Figure 4: Schematic (A) and pressure-enthalpy (P-h) process diagram (B) for Configuration B. DHP = downhole pump, PW = Production Well, HE1= geothermal preheater, ST = steam turbine, C = condenser, IW = Injection well, P = surface pump, BIO = biomass boiler. Red-line = hot geofluid, blue-line = cold geofluid, grey-line = working fluid (distilled water), dotted-black line = CO_2.

rate of 2.9 kg/s with a CO_2 emissions rate of 2.5 kg/s. Parasitic loads for surface pumps, downhole pumps and CO_2 compression are considered.

Configuration B is a geothermal-BECCS configuration where the geofluid performs feedwater heating for a bioenergy-based thermal power station with distilled water as the working fluid (Figure 4). Again, 168 kg/s of geofluid at 160°C heats 105 kg/s of distilled water from 43°C to 147°C (621 kJ/kg). This is notably lower than the liquid saturation point of water (885 kJ/kg). Typical of a thermal power plant, the distilled water is heated from 147°C to superheated steam at 500°C (3470 kJ/kg). The biomass burn rate is significantly higher at 24.4 kg/s, with a CO_2 emissions rate of 21.4 kg/s.

Complete geofluid reinjection is assumed for all plants. Both Configuration A and B deploy in-line dissolution at 50 bar within reinjection wells. Using the hydrostatic column of the well, this would correspond to a bubbler depth of 400 m if the reinjection wellhead pressure was 10 bar. The solubility of CO_2 at these conditions is roughly 0.021 kg per kg of water (Duan & Sun, 2003), meaning that a maximum of sequestration capacity of 3.5 kg/s of CO_2 is possible.

Biogenic CO_2 can be considered a valuable resource to certain industries like horticulture, carbonated drinks or even jet fuel (de Kleijne et al., 2022). Any excess biogenic CO_2 that could not be sequestered based on this maximum sequestration capacity was assumed to be sold at market price for direct use.

The LCOE was then determined at 2022 conditions (NZD 140/tonne feedstock, NZD 80/tonne CO_2) and 2035 conditions (NZD 70/tonne feedstock, NZD 160/tonne CO_2) with NCF and payback period calculated for both using a wholesale electricity price of NZD 90/MWh. Finally, sensitivity analysis on LCOE and recovery period was performed by simultaneously changing feedstock (NZD 40-200/tonne) and CO_2 cost (NZD 40-225/tonne).

4. RESULTS AND DISCUSSION

The techno-economic results for 2022 and 2035 conditions are summarised in Table 1 and displayed on Figures 5 & 6. The 2022 wholesale electricity price range for the central North Island is shown for comparison.

For 168 kg/s of geofluid at 160°C, net plant capacity was 5.7, 9.7 and 92 MWe for the benchmark plant, the geothermal-BECCS ORC plant (Configuration A) and the geothermal-BECCS preheat plant (Configuration B), respectively. The overall parasitic load was only 1.2 MWe for the benchmark plant, comprised of the downhole pumps and the working fluid surface pump. In contrast, the CO_2 compression needed for in-line dissolution increased the total parasitic load to 2.4 MWe for both configuration A and B. Configuration B had the highest overall utilization efficiency at 18.5%. Configuration A had a slightly lower utilization efficiency of 6.9% when compared to the benchmark plant due to the higher relative parasitic load.

Configuration A had a high negative emissions intensity rate of -928 gCO_2/kWh, offsetting emissions at almost the rate produced by coal plants. Due to only being able to capture 17% of the biogenic emissions from Configuration B with in-line dissolution, this plant had a much lower emissions intensity rate at -137 gCO_2/kWh. However, it had a higher overall gross emissions rate at 110 kT/year of CO_2, compared to 79 kT/year for Configuration A.

Although Configuration B had by far the largest CAPEX, the capital cost rate (NZD 5494/kWe) was relatively close to the benchmark plant (5076 NZD/kWe), below the median values of new plants (NZD 6346/kWe) in 2021 (IRENA, 2021). The capital cost rate for Configuration B was higher but still within the overall range of new plants in 2021 at NZD 8209/kWe.

For 2022 conditions, the LCOE of the benchmark geothermal plant is NZD 78/MWh, which is lower than the average of new plants in 2021 at roughly NZD 105/MWh (IRENA, 2021). This plant breaks even just after 20 years.

In contrast, assuming today's carbon price of NZD 80/tonne and a plant gate cost for forestry waste at NZD 140/MWh, Configuration A had an LCOE of NZD 203/MWh and Configuration B had an LCOE of NZD 163/MWh.

Table 1: Techno-economic model results for all plants

	Benchmark	Configuration A	Configuration B
Generated Power (MWe)	6.9	12.1	94.4
Parasitic Load (MWe)	1.2	2.4	2.4
Net Power (MWe)	5.7	9.7	92.0
Utilization Efficiency (%)	7.7	6.9	18.5
Emissions Intensity (gCO_2/kWh)	0	-928	-137
Gross Sequestration (kT/year)	0	79	110
CAPEX (Million NZD)	29	79	506
Capital Cost Rate (NZD/kWe)	5076	8209	5494
LCOE in 2022 (NZD/MWh)	78	203	163
LCOE in 2035 (NZD/MWh)	78	54	29

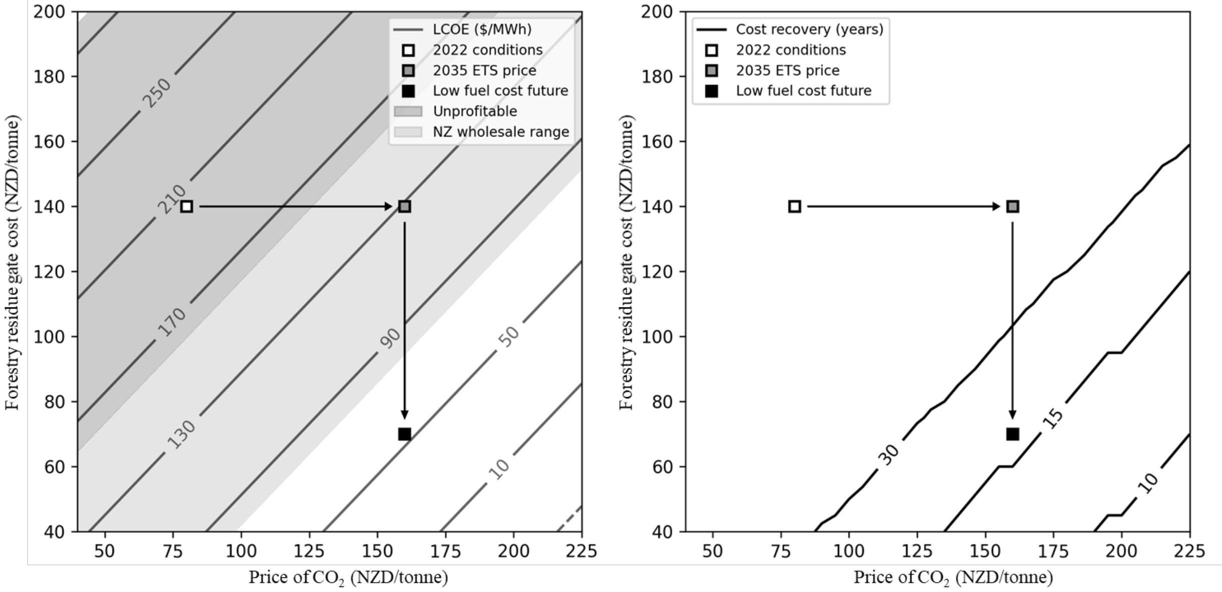


Figure 5: Sensitivity plot of LCOE (A) and payback period (B) for Configuration A.

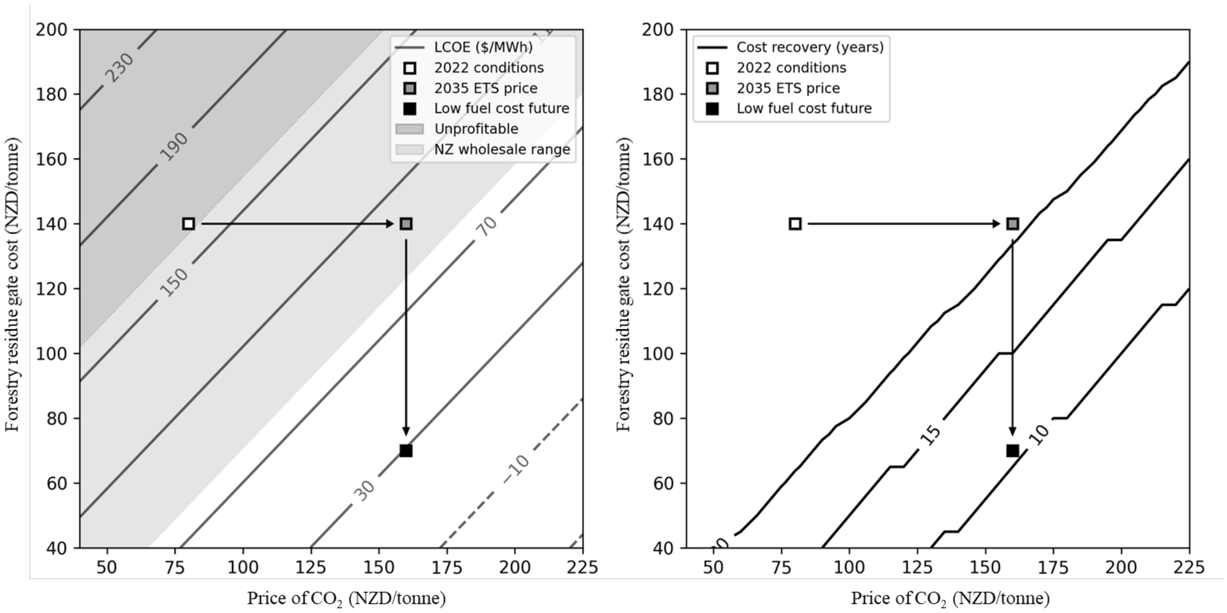


Figure 6: Sensitivity plot of LCOE (A) and payback period (B) for Configuration B.

These values are cheaper than the estimated LCOEs of standalone BECCS powerplants overseas, NZD 267 to 426/MWh (Emenike et al., 2020; Yang et al., 2021), while also in line with overseas values (EIA, 2022) of other emerging generation technologies such as new biomass plants (NZD 143/MWh), offshore wind (NZD 216/MWh) and battery storage (NZD 203/MWh). However, at a wholesale electricity price of NZD 90/MWh neither geothermal-BECCS configurations was able to achieve a payback period within a plant life of 30 years (Figures 5 and 6).

For the 2035 conditions, the LCOE of the benchmark plant is unaffected by the increase in CO_2 price (NZD 160//tonne CO_2) or the reduction in plant gate cost for forestry residues (NZD 70/tonne) and remains constant at NZD 78/MWh. However, there is a dramatic shift for both Configuration A and B to NZD 54/MWh and NZD 29/MWh, with both plants now significantly outperforming the benchmark. Configuration A and B can break even at ~15 and ~10 years respectively even at a wholesale price of NZD 90/MWh. (Figures 5 and 6).

Sensitivity analysis is useful to see how the trends in plant gate cost and the price of CO_2 affect LCOE and payback period. For example, if the price of CO_2 does increase to NZD 160/tonne by 2035 but the plant gate cost remains at NZD 140/tonne, then Configuration A still cannot break even within the life of the plant. In contrast, Configuration B would break even only slightly beyond 30 years. If the plant gate cost decreased to around NZD 100/tonne, then the payback period would be around 30 years for Configuration A and around 15 years for Configuration B. If the CO_2 price increased to NZD 225/tonne, with no change to the plant gate cost, then the LCOE would be around NZD 70/MWh for Configuration A and NZD 50/MWh for Configuration B.

Trends in lower feedstock gate costs and higher CO_2 spot prices could enable geothermal-BECCS to be a useful decarbonization tool. For example, if Configuration A was scaled to a nominal size for an ORC power plant (Ngatamariki, ~100 MWe), and Configuration B was scaled to a similar size to a thermal power station (Huntley, ~1 GWe), both would be able to sequester on the level of 1 Mt of CO_2 per year.

These results show that there are reasonable 'price markers' for feedstock gate cost and CO_2 price under which geothermal-BECCS could be deployed to boost renewables and remove CO_2 and be financially viable in Aotearoa. However, as of 2022, the bioenergy market remains in its infancy as compared to other countries. Despite the sharp increase in CO_2 price in the past two years, a higher price is still required before this negative emissions technology becomes economically feasible. While this study focused on low temperature geothermal systems at 160°C and forestry waste for feedstock, for practical applications of geothermal-BECCS different combinations of both should be tested and optimized based on site specific analysis and resource colocation. Certain physical properties of the feedstock, such as energy density, moisture and ash content could have a significant impact on costs and power output. Another synergy that could be interesting to explore for a geothermal-BECCS configuration is to use waste heat to dry the feedstock prior to combustion, which might improve plant efficiency.

Geothermal-BECCS could theoretically be applied as a retrofit to existing plants operating below design capacity as long as the necessary engineering challenges are considered. For example, flash plants with direct contact condensers must be careful to avoid oxygen corrosion. The well costs made up a large element of the CAPEX for all three plants in this study. Geothermal-BECCS rebalances the value of a well as not just a mechanism for heat-mining but also a tool for sequestration capacity, potentially establishing new feasibility thresholds for well depth and temperature during exploration. Additionally, previously determined 'low temperature' wells drilled during field exploration stages could be used for geothermal-BECCS operations, saving costs.

Configurations of geothermal-BECCS could also offer flexible renewable power. For example, configuration B could fulfil a similar role to natural gas power stations where energy can be ramped up during sharp increases in demand by burning more biomass to heat the distilled water to a higher threshold. This scheme could allow the plant to take advantage of both base load and higher value peak wholesale price while ensuring overall grid stability. If a geothermal-BECCS unit is deployed in tandem to conventional geothermal units as part of a wider field development strategy, then biogenic CO_2 emissions can be distributed for sequestration through all reinjection wells in the field. Alternatively, excess biogenic CO_2 emissions can possibly be sold as green CO_2 for direct use for horticultural activities, soda carbonation or jet fuel. Optimization between those two options will depend on logistical challenges, demand for green CO_2 and other market factors.

Despite BECCS featuring prominently in climate mitigation pathways (Fridahl & Lehtveer, 2018) set by the Intergovernmental Panel on Climate Change (IPCC), there are far fewer dedicated policy incentives for negative emission technologies than traditional renewable energy technologies worldwide. This is also true in Aotearoa, Ara Ake's 'Carbon Dioxide Removal and Usage' report (Ara Ake, 2022) suggests the conversation around negative emissions has begun. Given geothermal-BECCS potential to contribute to Aotearoa's climate targets, we believe that the conversation should expand beyond techno-economic feasibility and into the realm of social and cultural implications with regards to sequestering atmospheric and biogenic CO_2 within geothermal reservoirs.

Future improvements to this work include use of more localized cost correlations and rates such as for apparatus sizing and in-line dissolution. The levelized cost of sequestration (LCOS) could also be calculated to compare geothermal-BECCS to other negative emissions technologies like to geothermal-DACCS (Ara Ake, 2022). Additionally, optimization techniques could be applied to find feasible solutions given sensible ranges for all parameters. It is important that in any practical application of using a geothermal reservoir for both power production and CDR, care is taken to avoid any adverse effect on either.

5. CONCLUSION

This study has quantified the financial viability of geothermal-BECCS (Bioenergy Carbon Capture and Storage) systems in Aotearoa. We developed a techno-economic systems model that demonstrated the power production, negative emissions intensity and LCOE for two geothermal-BECCS configurations: a hybrid ORC plant (Configuration A) and a hybrid feedwater system (Configuration B). For 168 kg/s of geofluid at 160°C, a benchmark geothermal plant produced 5.7 MWe at 7.7% efficiency and an LCOE of NZD 78/MWh. Considering a 2022 CO_2 price of NZD 80/tonne and an estimated feedstock cost of NZD 160/tonne, Configuration A produced 9.7 MWe at 6.9% effficiency with an emissions intensity of -928 gCO_2/kWh and an LCOE of NZD 203/MWh. Under the same conditions, Configuration B produced 92 MWe at 18.5% efficiency with an emissions intensity of -137 gCO_2/kWh and LCOE of NZD 163/MWh. These values are cheaper than the LCOEs of standalone BECCS plants overseas from NZD 267/tonne to NZD 426/tonne.

If the CO_2 price rises to NZD 160/tonne by 2035, and a median gate cost of NZD 70/tonne can be achieved, the LCOE of Configuration A and B fall sharply to NZD 54/MWh and NZD 29/MWh, outperforming the benchmark geothermal plant. Thus, the price of CO_2 must be sufficiently high such that the market incentivises negative emissions and carbon dioxide removal. Conversely, the price of biomass feedstock should be low enough to warrant power hybridization. If these circumstances are met, geothermal-BECCS can be a financially promising power production and negative emissions tool in meeting Aotearoa's climate targets.

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APPENDIX

Table A1: Model assumptions

Reservoir Pressure (bar)	50	Discount rate (%)	8 (IRENA, 2021)
Number of production wells	3	Construction Period (years)	2
Number of injection wells	3	USD Conversion (NZD)	1.59
Production well depth (m)	500	Pound Sterling Conversion (NZD)	1.9
Injection well depth (m)	700 (Gunnarsson et al., 2018)	Euro Conversion (NZD)	1.61
Ambient Temperature (°C)	20	Biomass Higher Heating Value (kJ/kg)	15350 (Thain & DiPippo, 2015)
Temperature of cooling water outlet (°C)	40	Biomass Specific Exergy (kJ/kg)	16350 (Thain & DiPippo, 2015)
Heat transfer coefficient (water-isopentane), W/m^2K	568 (DiPippo, 2016)	Pump efficiency (%)	75 (DiPippo, 2016)
Heat transfer coefficient (water-water), W/m^2K	1200 (DiPippo, 2016)	Boiler efficiency (%)	80
Isopentane Condenser pressure (bar)	1.86 (DiPippo, 2016)	Sparger Depth (m)	400
Water condenser pressure (bar)	0.09 (DiPippo, 2016)	Boiler capital cost rate (NZD/kWth)	1000 (Windsor Energy, 2022)