Carbon Negative Geothermal: Theoretical Case Study for Biogenic CO_2 Removal at Ngāwhā Power Station

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ABSTRACT

Geothermal energy is a mature and base load source of low carbon electricity in New Zealand, and the only one that can facilitate onsite carbon dioxide removal (CDR). Here, we investigate the potential for bioenergy hybridisation and biogenic CDR using existing reinjection wells at Ngāwhā geothermal field. The proposed designs would produce increased electricity generation and negative CO_2 emissions.

Bioenergy hybridisation is achieved with biomass combustion that directly increases the enthalpy of production fluid before or after a separator. Mass-energy balance determines the optimal biomass burn rate to sustain turbine delivery enthalpy in the face of resource decline. We calculate the potential CO_2 emissions that can be sequestered via dissolution in the reinjection line. Finally, we estimate high-level economic indicators for this retrofit.

Our findings suggest that it is possible to increase plant capacity by 1 MWe through combustion of 24 kt/year of forestry residues. The cost of new electricity generation could be competitive with conventional geothermal projects at CDR investment prices as low as \$75/tCO_2. Conversely, the cost to remove biogenic CO_2 through this process could range between \$77-154/tCO_2 depending on the configuration, which is more cost effective than most direct and indirect atmospheric carbon removal schemes (Fasihi et al., 2019). Monetized on international markets, CDR revenues could reach USD \$3.9 million per year, which adequately covers anticipated biomass fuel costs of USD \$2.1 million per year.

Applications of CDR technologies in New Zealand can decarbonise hard to abate emissions from agriculture, steel and aviation. CDR via geothermal reinjection wells makes use of onsite infrastructure and mitigates CO_2 buoyancy risks, allowing for cost-effective and secure storage. In addition, hybridisation with bioenergy could alleviate or delay the need to drill more wells to maintain plant capacity. This can be important if fluid production is nearing a geothermal field's maximum allowable consent.

1. INTRODUCTION

Geothermal innovation has played a critical role in Aotearoa New Zealand's history. Since the 1300s, North Island Māori have held a spiritual and physical relationship with geothermal energy (Taute et al., 2022), in the form of cooking, heating and therapeutic uses.

Today, new geothermal technologies emerge in Aotearoa with the intent of facilitating the net-zero transition and combating the climate crisis. These include investigations into supercritical geothermal systems for higher base load capacities (Chambefort et al., 2020) coproduction of hydrogen at Mokai power plant (Thomas et al., 2020), and the extraction of lithium from geothermal brine in Taupo (Sajkowski et al., 2023).

Combining geothermal energy with bioenergy-based carbon dioxide removal is another opportunity for impactful innovation in Aotearoa. Bioenergy and geothermal energy are thermodynamically synergistic (Dal Porto et al., 2016; Thain & DiPippo, 2015) and the geological storage of biogenic CO_2 is carbon negative (Lehtveer & Emanuelsson, 2021).

Geothermal plant operators face risks that fields won't meet design capacity due to production decline. Additionally, expensive well investments may strike cold zones on the margins of a geothermal prospect. Finally, continued development of the geothermal resource will run into eventual consent take limits, especially if there are nearby protected geothermal cultural and tourism sites.

Bioenergy hybridization addresses these challenges. In turn, the injection of biogenic CO_2 that is originally drawn from the atmosphere, may be a cost-effective way to offset emissions elsewhere or even achieve negative emissions. Given that both geogenic and atmospheric CO_2 are already dissolved in and injected with geothermal brine at some power plants around the world (Ratouis et al., 2022), biogenic CO_2 removal (CDR) is the natural next step for utilitarian geothermal development.

Here, we model the techno-economic feasibility of two geothermal, bioenergy and carbon capture and storage (geothermal-BECCS) hybrid retrofit configurations at the Ngāwhā geothermal power station. Bioenergy from woody biomass is used to increase the enthalpy of two-phase geothermal fluid prior to the separator, thereby increasing the mass fraction of steam but maintaining its separated temperature. Biogenic CO_2 is then compressed and dissolved in reinjectate alongside the existing geogenic emissions from the base plant.

1.1 Background of Ngāwhā Geothermal Power Station

The Ngāwhā geothermal power station is owned by Top Energy and situated in the Ngāwhā geothermal field (Fig. 1), east of Kaikohe in the Far North region of Aotearoa. With an estimated resource temperature of 230°C, it is the only commercial scale plant outside of the Taupō Volcanic Zone (TVZ). Ngāwhā power station consists of four Ormat Energy Converter (OEC) binary units.

The geothermal fluid is two-phase at the production wellhead and separated into steam and brine. The steam and brine passes through a series of heat exchangers to transfer thermal energy to a secondary working fluid in a closed loop.

The cooled geothermal fluid is then completely reinjected into the subsurface. The field has an existing consent for geothermal mass take and reinjection at 18.7 Mt/year.

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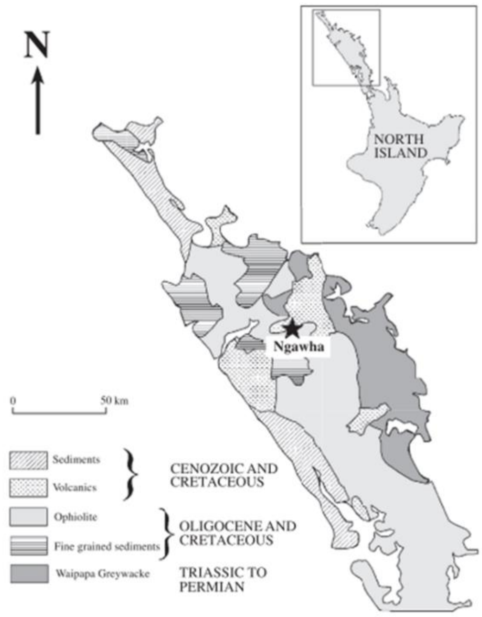

Figure 1: Location and geology of Ngāwhā geothermal field (modified from Aggarwal et al., 2023)

Ngāwhā currently generates 57 MWe, divided between its original units OEC 1, 2 & 3 (25 MWe) and the more recent OEC4 (32 MWe). Previously, the power station had the highest geogenic CO_2 emissions intensity (EI) among Aotearoa's geothermal generators at 300-400 gCO_2/kWh, almost on par with natural gas plants (McLean et al., 2020). When factoring methane as well, recent emission rates were recorded at around 128 $ktCO_2$eq/year. In 2022 Ngāwhā underwent a rapid conversion to reinject the naturally occurring non condensable gases (NCGs) by the end of 2023. Thus, there will be complete reinjection of geogenic CO_2 via dissolution in geothermal reinjection fluid.

The concentration of CO_2 from the Ngāwhā geothermal reservoir has been reducing since the plant was first commissioned in 1998 due to degassing of the field. CO_2 originally made up 2% by mass of total produced fluid but has declined to below 0.5% by mid-2022. It is estimated that there is a total of 20,000 kt of CO_2 in the Ngāwhā reservoir, with a total of 1,000 kt extracted and vented off due to power production to date. It is also predicted that a natural recharge of CO_2 from deep in the reservoir over this same period has only been 1.5 kt.

The current gas break-out pressure which may be required to keep the existing CO_2 in solution is around 13.5 bar at 94 °C and 0.5% CO_2 by mass well below the design pressure of the reinjection system at Ngāwhā (25-30 bar). However, the analytical gas break-out pressure was predicted to be around 20 bar. This presents an opportunity for some amount of non-geogenic CO_2 emissions to be injected alongside the plant's existing emissions. Utilizing the remaining solubility space for the removal and storage of biogenic CO_2 is particularly interesting because bioenergy hybridization of geothermal is one way to further increase the capacity of an existing power station.

1.2 Geothermal and Bioenergy Hybrids

Geothermal energy and bioenergy are two synergistic renewable energy resources. Bioenergy can be used to superheat geothermal steam to temperatures beyond what would normally occur in the reservoir. This was done in practice at the Cornia-2 geothermal flash plant in Lardarello, Italy, where geothermal steam was superheated from 150°C to 375°C prior to turbine entry (Dal Porto et al., 2016).

At binary plants, geothermal fluid can be heated by biomass waste heat (Briola et al., 2019) before the organic Rankine cycle (ORC) or a bioenergy heat exchanger can be installed after the conventional vaporizer and preheater to superheat the working fluid (Toselli et al., 2019).

Although there are no geothermal-bioenergy hybrids currently operating in Aotearoa the topic has been investigated in the past. Thain & DiPippo (2015) investigated a theoretical geothermal-bioenergy retrofit at the Rotokawa power station, which was predicted to yield an increase in net power by 8.5 MWe by superheating the separated steam.

Additionally, several retrofit configurations for the Wairakei geothermal field were considered by Chester (2016). The different configurations were predicted to require capital investments of $ 1.2-5.6 million/MWe (NZD). Although these retrofits were deemed uneconomic due to the high capital and fuel costs, and low monetary gains from increased electricity production, a secondary stream of revenue from biogenic CO_2 removal may have shifted the cost-benefit dynamic.

1.3 Carbon Dioxide Removal via Geothermal Reinjection

Geothermal power plants in Aotearoa emit geogenic CO_2 at an average rate of 75 gCO_2/kWh (McLean et al., 2020). In recent years, these emissions have come under scrutiny, with efforts to reinject them underway at Ngatamariki (Ghafar et al., 2022) and Te Huka (Choudhary et al., 2021) power stations.

The transport mechanism to return the CO_2 back to the subsurface is dissolution within geothermal reinjection fluid, different to the supercritical state CO_2 injection of conventional carbon capture and storage (CCS). This avoids buoyancy related leakage risks, provided reservoir pressure is maintained. However, total emissions storage is limited by the solubility of CO_2 in water (Kervévan et al., 2017). Perhaps most importantly, the use of onsite reinjection wells cuts transport and infrastructure costs significantly.

Reinjection of geogenic CO_2 has been underway at the Carbfix project in Iceland for over a decade to establish truly carbon neutral electricity generation (Ratouis et al., 2022). The Carbfix project has since expanded to incorporate direct air carbon capture and storage (DACCS) at the Hellisheidi geothermal field to facilitate a carbon negative electricity generation process. A pilot scale plant was installed in 2017, stripping 50 tCO_2/year from ambient air and sequestering it within basalt formations via mineralization (Ratouis et al., 2022). Although the geology of Aotearoa is different than Iceland, Marieni et al. (2018) show that CO_2 mineralization can occur in rhyolitic formations. However, further surveys of reaction rates are needed in New Zealand.

By nature, DACCS activities incur a parasitic load. This means that widespread adoption of DACCS at geothermal power plants will reduce their net capacity. Conversely, combining geothermal with bioenergy and carbon capture and storage (BECCS) can increase the electricity generation from geothermal resources (Titus et al., 2023). While the reinjection of geogenic CO_2 prevents further radiative forcing and climate damage, the injection of biogenic CO_2 specifically reverses these. Increased renewable energy lowers the overall cost of carbon dioxide removal, whereas monetizing geological storage of CO_2 adds an additional revenue stream to the geothermal plant owner. This makes geothermal-BECCS worth investigating as a strategic decarbonisation tool for Aotearoa and beyond.

2. METHODOLOGY

For this study, we investigate using bioenergy to heat the total produced geothermal fluid before the separator, feeding to OEC 1 & 2, to increase the mass fraction of steam entering the vaporizer. Each configuration is optimized to achieve a net increase of 1 MWe. We then determine the maximum dissolvable biogenic CO_2 emissions for two different geothermal-BECCS configurations. The first utilizes the existing reinjection infrastructure at Ngāwhā via surface dissolution at a maximum pressure of 20 bar. The second examines a retrofitted reinjection system with down-well, in-line dissolution where the pressure required is optimized up to a limit of 50 bar.

For both configurations, the biomass is assumed to be combusted in pure oxygen to achieve a flue gas of very high-grade CO_2 (>95%), critical for dissolution in geothermal fluid. This requires a parasitic load to separate O_2 from air. A geothermal-bioenergy hybrid configuration, without any biogenic CDR, is also evaluated for comparison purposes.

Renewable electricity generation and CDR are valuable for Aotearoa to tackle the climate crisis. Thus, it is important to know the cost to produce the additional 1 MWe and the cost to remove each tonne of CO_2 from the atmosphere for geological storage. For the purpose of this study, we assume that CDR is an internationally marketable service (Wenger et al., 2022). All monetary values are expressed in US dollars ($) unless otherwise indicated.

2.1 Geothermal-BECCS Systems Model

We use the Titus et al. (2023) thermodynamic systems model to determine the techno-economic feasibility of theoretical geothermal-bioenergy and geothermal-BECCS retrofits at Ngāwhā power station. The model represents the conservation of mass and energy of a controlled geothermal fluid flow volume at each state of transit through a given geothermal plant. Briefly, the model calculates:

1. For a geothermal separator, the mass fractions of steam and brine at the exit given the initial two-phase fluid conditions;
2. For a biomass boiler and heat exchanger, the energy imparted to the geothermal fluid at a given biomass burn rate;
3. For the given biomass feedstock, the subsequent biogenic CO_2 emissions;
4. For brine reinjected, the maximum dissolvable biogenic CO_2 based on dissolution temperature, pressure and existing geogenic CO_2 content;
5. All O_2 separation and CO_2 compression loads as required;
6. If the plant uses a steam turbine, the net electrical power produced for given steam enthalpy, mass rate and turbine exhaust conditions;
7. And/or if the plant uses an Organic Rankine Cycle (ORC), the net electrical power produced by the binary turbine given the thermal energy imparted by the geothermal fluid, and the cycle pressure and mass rate of the working fluid;

The key technical outputs of the model are thus net power (MWe), annual biomass feedstock requirement (tonnes/year), and annual biogenic CDR (tCO_2/year). In addition to these, two key economic outputs are calculated by the Titus et al. (2023) model:

a. The levelized cost of electricity (LCOE), which is the net present value (NPV) of all costs of the geothermal development per unit of electricity produced. This metric allows for techno-economic comparison with any electricity generation technology;
b. The levelized cost of sequestration (LCOS), which is the NPV of all costs of the geothermal development per unit of CO_2 sequestered. This metric allows for techno-economic comparison with any CO_2 sequestration activity.

In this study, we aim to assess the viability of specifically retrofitting the Ngāwhā power station for coupled enhanced electricity generation and CDR activities. Therefore, we modify LCOE to the levelized cost of new electricity ($LCNE$), determined via the following equation:

$$LCNE = \frac{C_{new} - R_{CDR}}{G_{new}} \tag{1}$$

where C_{new} is the NPV of new costs of retrofitting the plant, given in $. This includes new investment, operation, and fuel costs. R_{CDR} represents the NPV of revenues from biogenic CO_2 removal, also given in $. R_{CDR} is determined by the saleable price of CO_2 permanently removed from the atmosphere and will vary depending on localized market contexts. G_{new} is the NPV of new electricity generated by the retrofit plant, given in MWh.

$LCNE$ is useful to compare geothermal-BECCS with other potential retrofit activities, such as the expansion of the steam field via new wells or solar-hybridization but cannot be used to compare retrofit activities that may decrease the net plant capacity such as geothermal-DACCS.

Similarly, we modify LCOS to the levelized cost of carbon removed ($LCCR$), using the following equation:

$$LCCR = \frac{C_{new} - R_G}{E_{CDR}} \tag{2}$$

where C_{new} remains the same as in Eqn. 1 but R_G represents the NPV of revenues from electricity generation, given in $. The revenue term is now determined by the local electricity market. E_{CDR} represents the NPV of CO_2 removed from the atmosphere over the lifetime of the plant (notably excluding the reinjection of geogenic CO_2). This allows for comparison between any net negative emissions technology.

We calculate LCCR and LCNE for a range of prices of electricity, woody biomass feedstock and CO_2. This provides insight into the market conditions, ranging from the local emissions trading scheme (ETS) to internationally traded carbon markets, that allow geothermal-BECCS retrofits to be cost competitive with conventional geothermal power plants. Where relevant, reference prices of $100/tonne (Wenger et al., 2022), \$88/tonne (MPI, 2020), and \$60/MWh (Keith et al. 2018) are assumed for CO_2, woody biomass and electricity, respectively.

We assume an average retrofit plant life of 15 years and a discount rate of 8%, representative of expected projects in OECD countries (IRENA, 2019; Park et al., 2021). We accounted for 2 years for retrofit construction, a boiler efficiency of 80% and a capacity factor of 90%. Furthermore, we assume woody biomass with a heating value of 16000 kJ/kg (Thain and DiPippo, 2015) and a CO_2 emissions factor of 1.6 kg/kg-wood (Puettmann et al., 2020) as the feedstock. The capital cost rates for the boiler, air separator unit (ASU) and compression unit (CPU) are \$2353/kWe (IRENA, 2021), \$185.5/kWe and \$200.4/kWe (Khallaghi et al., 2021), respectively. We assumed a 20% contingency.

The operational cost for the biomass boiler was 6% of the boiler capital cost (IRENA, 2021). The operational cost for the ASU and CPU combined were 4% of the respective capital cost. The parasitic load for the ASU and CPU were 184 kWh/tO_2 and 100 kWh/tCO_2 (Hanak et al. 2017), with 12.15 tO_2/kWe required per year (García-Luna et al. 2022).

For configurations with down-well dissolution, we include annual onsite-transport, injection and monitoring costs to total \$3.5/tCO_2 (Gunnarsson et al., 2018). Finally, we used a 13% thermal-electrical efficiency for the OEC units, calibrated to the existing plant. A higher enthalpy source fluid would lead to higher efficiency, but not applied to stay conservative in the analysis.

3. RESULTS

3.1 Geothermal-BECCS Model Configurations

3.1.1 Configuration 1: Geothermal-Biomass Hybrid

Configuration 1 is a geothermal-bioenergy hybrid without any biogenic CDR, optimized to produce an additional 1 MWe net over the base plant. Approximately 400 t/h of geothermal fluid is drawn from the production well and dispatched towards OEC1&2 at an enthalpy of ~990 kJ/kg (Fig. 2).

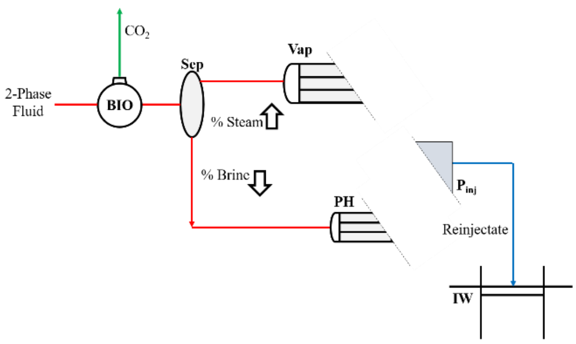

Figure 2: Simplified Process Schematic of Geothermal-Biomass Hybrid

The geothermal fluid enters the bioenergy heat exchanger and leaves at an enthalpy of ~1040 kJ/kg. This requires a biomass burn rate of ~1.5 t/h. Because high-grade CO_2 is not required for this configuration, there are no costs or parasitic loads associated with oxycombustion.

Afterwards, the geothermal fluid enters the separator (13.5 bar) with 11% exiting as steam and 89% as brine. This steam mass fraction increases by ~2% over the original plant. The steam and brine are then dispatched to the vaporizer and preheater respectively prior to reinjection.

Geogenic CO_2 is reinjected under the same conditions as the base plant, but 19.3 kt/year of biogenic CO_2 is vented to the atmosphere. The total retrofit capital cost is \$3.3 million.

3.1.2 Configuration 2: Geothermal-BECCS with Surface Dissolution

Configuration 2 is a geothermal-BECCS retrofit plant that makes use of the existing injection infrastructure (surface dissolution, limited to 20 bar) at Ngāwhā to dissolve the maximum allowable biogenic CO_2 (Fig. 3). This configuration has a similar setup to configuration 1, except that high-grade CO_2 is now required for dissolution in reinjectate, thus incurring costs and parasitic loads for oxycombustion. Thus, to achieve 1 MWe net increase over the original plant, the 2-phase geothermal fluid must be heated from ~990 kJ/kg to ~1069 kJ/kg, requiring a biomass burn rate of ~2.4 t/h.

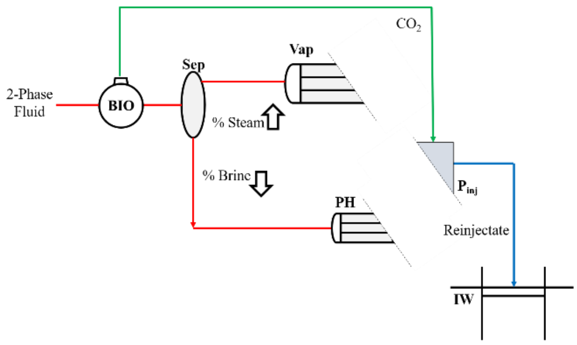

Figure 3: Simplified Process Schematic of Geothermal-BECCS with Surface Dissolution

The new steam mass fraction post separator is 12.5%. After prioritizing the reinjection of geogenic CO_2, roughly 14.3 kt/year (0.4% of produced fluid mass rate) of additional biogenic CO_2 can be dissolved and stored in the reservoir. This leaves 16.5 ktCO_2/year vented to the atmosphere. Only the dissolved biogenic CO_2 incurs a compression load from the CPU, but both dissolved and vented CO_2 contribute to the O_2 requirement and ASU load. The total retrofit capital cost is \$5.3 million.

3.1.3 Configuration 3: Geothermal-BECCS with Down-well Dissolution

Configuration 3 is a geothermal-BECCS plant where the injection apparatus is modified to include an interior pipe within the reinjection well for in-line dissolution of biogenic CO_2 (Fig. 4).

This allows the hydrostatic column to increase the effective dissolution pressure beyond the 20 bar surface limit, allowing for the maximum CDR possible. To attain a net increase of 1 MWe, the enthalpy of 2-phase geothermal fluid is increased from 990 kJ/kg to 1090 kJ/kg, resulting in a steam mass fraction of 13.6%.

This requires a biomass burn rate of 3.1 t/h, which in turn results in 39 kt/year of biogenic CO_2, approximately 1.1% of the total produced fluid mass. The optimal dissolution pressure to inject the entirety of this CO_2, alongside the geogenic emissions of the plant, is ~39.2 bar.

Factoring the range of reinjection pump pressure at Ngāwhā (25-30 bar), the biogenic CO_2 could be released from the interior pipe into the hydrostatic column between 90-140 m. The total retrofit capital cost is $6.7 million.

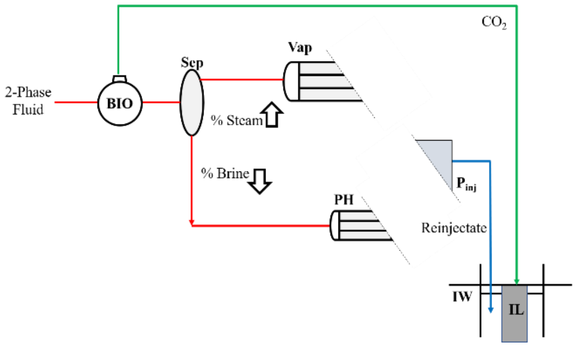

Figure 4: Simplified Process Schematic of Geothermal-BECCS with Down-well Dissolution

3.2 Model Results and market factor sensitivity

The key results presented in the previous sub-section are summarised in Table 1.

	Geothermal-Biomass Hybrid	Geothermal-BECCS (Surface Dissolution)	Geothermal-BECCS (Down-well Dissolution)
Gross Power Increase (MWe)	1	1.6	2
CPU and ASU Loads (MWe)	0	0.6	1
New Steam Fraction (%)	11	12.5	13.6
Biomass Burn Rate (t/h)	1.5	2.4	3.1
Biogenic CDR (kt/year)	0	14.3	39
Total CO_2 Mass Fraction (%)	0.5	0.9	1.6
Expected CAPEX (Mil. $)	3.3	5.3	6.7

The geothermal-biomass hybrid (configuration 1) has less than half the CAPEX of the geothermal-BECCS with down-well dissolution (configuration 3) due to the need for a smaller boiler, no air separation unit for oxy-combustion and no retrofit to the existing reinjection infrastructure at Ngāwhā power station.

Because of the 1 MWe parasitic load required for the CO_2 compression unit (CPU) and air separation unit (ASU) for configuration 3, the gross power increase from the station must reach 2 MWe, requiring a higher biomass burn rate (3.1 t/h) and therefore a larger boiler. This gross power increase requires some modification to the existing generation units. However, the shared steamfield configuration between OEC1, 2 and 3 allows the extra gross power load to be split between the units to minimize the cost of modifications, all the while keeping the biomass boiler central. When accounting for the co-injection of geogenic and biogenic CO_2, the total CO_2 mass fraction only reaches 1.6%, which remains lower than the 2% total CO_2 mass fraction in production fluid in 1998.

The geothermal-BECCS plant with surface pump dissolution (configuration 2) can remove biogenic CO_2 at less than half the annual rate (14.3 kt/year) than configuration 3 (39 kt/year) but requires 77% of the biomass burn rate and 79% of the total CAPEX.

For geothermal-BECCS configurations, the levelized cost of new electricity (LCNE) generated is sensitive to the saleable price of CO_2 removal (Fig. 5) and purchasing price of woody biomass (Fig. 6). Assuming a feedstock price of $88/tonne, the geothermal-biomass hybrid without any CDR retains a constant LCNE of $209/MWh irrespective of the CO_2 price.

This value is notably larger than the worldwide average LCOE of conventional geothermal plants (~$60-80/MWh; IRENA, 2021), meaning the retrofit is unlikely to be competitive with traditional field development measures.

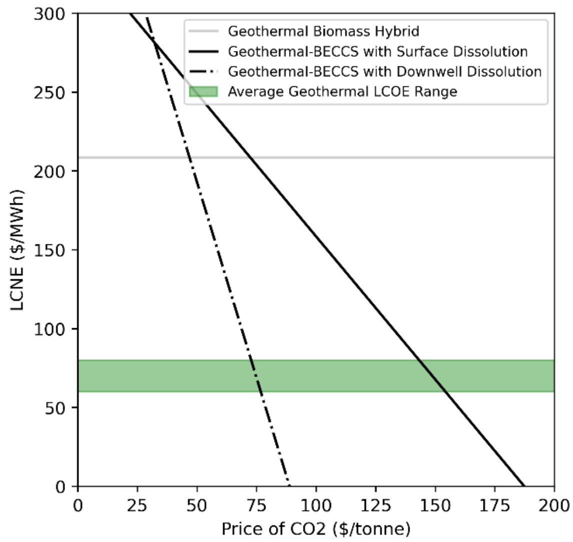

Figure 5: LCNE of retrofit configurations as a function of CO2 price (feedstock price at $88/tonne)

Configuration 2 surpasses configuration 1 at a CO_2 price of ~$90/tonne but doesn't become competitive with conventional geothermal until a CO_2 price of ~$140/tonne. Configuration 3 has a steeper slope than configuration 2 due to a larger pool of monetizable CO_2 offsetting the costs associated with a larger boiler, ASU and CPU.

Configuration 3 becomes competitive with conventional geothermal at a CO_2 price of ~$75/tonne and reaches and LCNE of $0/MWh at ~$90/tonne. This means that there is no net cost to generate the additional 1 MWe over time from the retrofit due to the revenues from synchronous CDR activities.

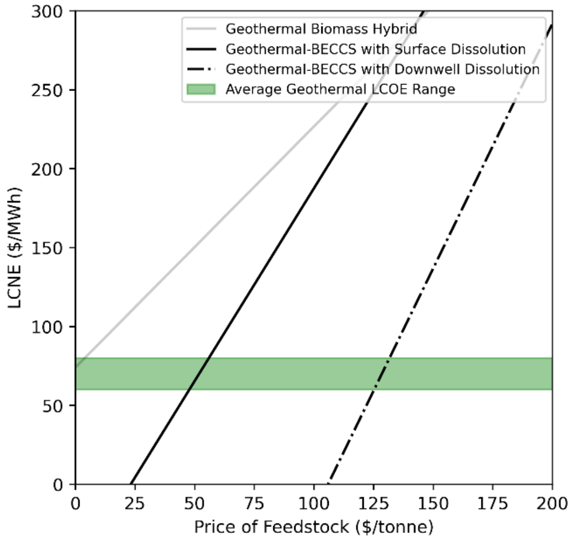

Figure 6: LCNE of retrofit configurations as a function of feedstock price (CO_2 price at $100/tonne)

To put these results in context, if CDR revenue was priced at 2023's average ETS value of $34/tonne (NZD $55/tonne), configuration 2 ($277/MWh) and 3 ($269/MWh) would be less viable than a geothermal-biomass hybrid without CDR, and all three plants would be uneconomic. However, if CDR is monetized at international market prices of ~$100/t$CO_2$, configuration 2 ($158/MWh) is over $50/MWh cheaper than configuration 1.

For configuration 3, the revenues from CDR are so substantial that the LCNE becomes $-55/MWh, meaning that retrofitting the plant to geothermal-BECCS for a 1 MWe increase would be beneficial even if the additional electricity revenue was disregarded.

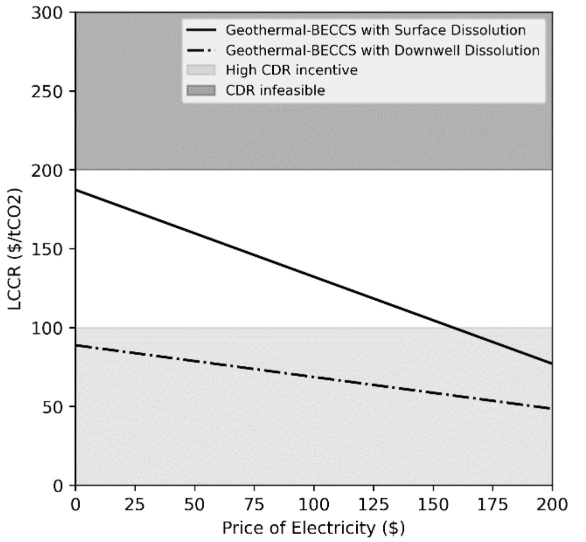

Figure 7: LCCR of retrofit configurations as a function of electricity price (feedstock price at $88/tonne)

Even at a high international market price of $100/t$CO_2$, the price of acquiring woody biomass can determine the economic viability of any potential geothermal-BECCS retrofit (Fig. 6). Configuration 1 only remains competitive with conventional geothermal if the price of feedstock is virtually free (<$10/tonne), whereas configurations 2 and 3 become viable at ~$60/tonne and ~$130/tonne, respectively.

The revenues from new electricity generated determine how cost effective geothermal-BECCS retrofits are at carbon removal (Fig. 7). Typically, CDR projects above $200/t$CO_2$ removed are considered infeasible (Fasihi, 2019), whereas projects that operate below $100/t$CO_2$ are considered efficient decarbonisation tools. Even if the new electricity generated by configurations 2 and 3 were not monetizable ($0/MWh), they would still have LCCR values below the uneconomic threshold. In the case of configuration 3, it would even remain below $100/t$CO_2$, demonstrating a very competitive CDR scheme.

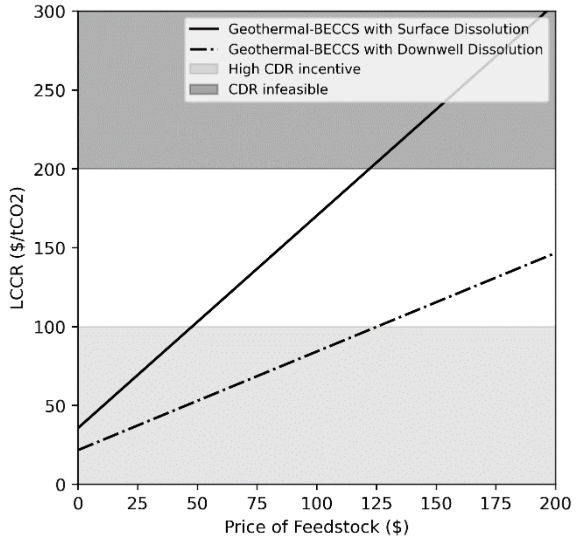

Figure 8: LCCR of retrofit configurations as a function of feedstock price (electricity price at $60/MWh)

Thus, feedstock price is a more important factor when determining LCCR (Figure 8), as configuration 2 passes the infeasible threshold at woody biomass prices >$115/tonne. Conversely, the LCCR for configurations 2 and 3 only drop below $100/t$CO_2$ at $50/tonne and $125/tonne, respectively

4. DISCUSSION

The acquisition of cheap biomass feedstock and ability to monetize CDR are key to the economic viability of geothermal-BECCS retrofits of existing geothermal plants. From a pre-feasibility perspective, it is possible for a geothermal-BECCS retrofit at Ngāwhā power station to be economically viable provided the market conditions are favourable. The dual revenues streams from electricity generation and carbon removal allow geothermal-BECCS to surpass geothermal-biomass hybrids at expected future CO_2 prices. However, international markets would most likely need to be leveraged in the short term and more work is needed to strengthen domestic policy in a way that enables removals trading.

For example, the total annual feedstock costs for configuration 1 were the lowest at ~$1 million when compared to configurations 2 ($1.7 million) and 3 ($2.1

million). However, 84% of configuration 2's annual feedstock costs were offset by the annual CDR revenue ($1.4 million). For configuration 3, the revenues from CDR ($3.9 million) were almost twice that of the feedstock costs for a given year.

Further points of technical investigation for geothermal-BECCS at Ngāwhā should include chemical considerations. The current concentration of CO_2 in the produced geothermal fluid is 0.5% by mass but could climb back to the original natural equilibrium of 2% more quickly if biogenic CO_2 is injected into the reservoir. As the concentration of CO_2 in the reservoir rises with time, the available brine dissolution capacity for biogenic CO_2 will diminish in the existing reinjection system, particularly with Case 2.

Monitoring efforts, such as tracer tests, are thus crucial to understand the migration paths of newly introduced CO_2 into the reservoir. Careful reservoir management may be required to limit CO_2 breakthrough in the production zone and avoid potential leakage through surface manifestation. Analysis for CO_2 mineralization rates will also be important to assess the durability of CDR activities over time.

Any geothermal-BECCS retrofit would require a sustainable and consistent supply of biomass. Maintaining an appropriate amount of onsite feedstock storage allows for enhanced low-carbon electricity production (by further increasing the steam fraction) during peak electricity prices, a valuable tool for Aotearoa's energy transition. Torrefaction of woody biomass may be of interest given the higher heating value when compared to unrefined wood products (Chen et al., 2021). Since thermal treatment is required for torrefaction, there may be additional synergies to explore with geothermal energy.

Biogenic CO_2 is a valuable product for other industries such as horticulture and aviation. If the geothermal-BECCS with surface dissolution (configuration 2) retrofit was altered slightly to include compression of non-dissolvable CO_2 (23.1 kt/year) in preparation for sale to greenhouses at the 2023 ETS price, the LCNE would drop by almost half from $158/MWh to $84/MWh. This is assuming that the 14.3 kt/year of dissolvable CO_2 is still valued at $100/tonne.

Given the context of Aotearoa's food-grade CO_2 shortage (Olley, 2023), further improving the purity of the boiler flue gas may be a valuable proposition. Earlier in 2023, the price of food-grade CO_2 had risen to NZD $3.5/kg (NZD $3500/tonne), which would yield revenues of NZD $80 million if the entirety of the 23.1 kt/year of non-dissolvable biogenic CO_2 was sold for this purpose. The scale of the supply to the market is technically feasible given that this value is close to the 24 kt/year supplied by the Kapuni plant prior to the shortage. This would be a better alternative than using scrubbed geogenic CO_2, which contains notable impurities such as H_2S, CH_4 and heavy metals.

There remain policy and cultural questions surrounding the injection of both biogenic and atmospheric CO_2 into Aotearoa's subsurface. A pilot scale installation of geothermal-BECCS, similar to the scale described in this study, may help inform future decision making in the carbon removal and climate mitigation space.

5. CONCLUSION

In conclusion, geothermal-BECCS retrofits of existing geothermal plants in Aotearoa are techno-economically feasible under reasonable market conditions when accounting for international carbon markets. For the Ngāwhā power station, we showed that achieving a net increase of 1 MWe is achievable by increasing the separated steam fraction between 11-13.6% with a biomass heat exchanger.

Almost half of the resultant biogenic CO_2 emissions (14.3 kt/year) can be dissolved alongside geogenic CO_2 emissions with no change to the existing reinjection infrastructure. With down-well dissolution, up to 39 kt/year of biogenic CO_2 can be dissolved and stored in the reservoir, permanently removed from the atmosphere. The total mass fraction of CO_2 in the geothermal reinjection stream increases from the 0.5% in 2023 to 0.9-1.6%, still below the original 2% from 1998.

At this scale, a sustainable supply of 24 kt/year of woody biomass would need to be sourced, costing up to $2.1 million. Capital investment costs range between $3.3-6.7 million. CDR revenue is key to recuperate these costs.

Cost effective CDR (<$100t/$CO_2$) is achievable due to the use of existing reinjection wells as a mechanism for reservoir storage. Geothermal-BECCS can be competitive with conventional geothermal plants at CO_2 prices as low as $75/tonne. A pilot demonstration of geothermal-BECCS can inform on reaction rates, policy frameworks, cultural considerations and Aotearoa's decarbonisation strategy.

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