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Carbon Negative Geothermal: Advanced Electricity Generation Cycle Featuring Geothermal with Bioenergy and Carbon Capture and Storage

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ABSTRACT

Geothermal energy has proven to be a reliable baseload resource with much lower emissions intensities on average (~122gCO_2/kWh; Bertani & Thain, 2002) than fossil fuel plants (400-1000gCO_2/kWh; EIA, 2021). Geothermal energy can be combined with bioenergy to generate electricity from low enthalpy systems or boost existing power output for plants performing below design capacity. The combination of geothermal energy with bioenergy and carbon capture and storage (BECCS) has the potential for dual decarbonisation through the aforementioned renewable power boosting and net negative carbon emissions. In this work, we classify what constitutes geothermal-BECCS and quantify its potential for electricity production and decarbonisation as a valuable tool to meet emissions reduction targets in New Zealand.

BECCS technologies are prominently featured in cost-effective emissions reductions pathways but currently have high levelized costs of electricity (NZD 267 to 426/MWh). If paired with geothermal, the reinjected brine serves as a vehicle for carbon sequestration, making use of existing well infrastructure and cutting offsite transport costs. Additionally, dissolving CO_2 in brine mitigates buoyancy risks associated with injecting free phase supercritical CO_2. Here, we present results from a systems model that characterizes key thermodynamic phenomena for four potential geothermal-BECCS configurations. This model allows us to quantify conversion efficiency, sequestration potential, and provide a preliminary estimate of likely costs.

After accounting for compression power, an existing flash plant retrofitted to geothermal-BECCS could produce 1.5 times more power than the original, at improved utilization efficiencies and have LCOE values as low as NZD 82-87/MWh by 2035. Additionally, the plant could sequester CO_2 at an emissions intensity rate of -163 to -263 gCO_2/kWh using only the separated brine.

1. INTRODUCTION

As current worldwide emissions reductions targets remain insufficient to mitigate global warming to 2°C, carbon dioxide removal (CDR) technologies may be necessary to limit atmospheric CO_2 concentration to below 450 PPM. One such technology, direct air carbon capture and sequestration (DACCS) has already been successfully paired with geothermal power production in Iceland to capture and store atmospheric CO_2 (O'Neill, 2022). In this research, we consider the techno-economic feasibility of hybridizing geothermal with a different form of CDR: bioenergy with carbon capture and sequestration (BECCS). This has the potential to simultaneously boost renewable power production while sequestering biogenic CO_2.

Pathways for climate change mitigation by the Intergovernmental Panel on Climate Change (IPCC) heavily feature BECCS technologies in global energy forecasts (Fridahl & Lehtveer, 2018). The advantage of using geothermal powerplants for BECCS (Figure 1) is that onsite reinjection infrastructure could be leveraged for sequestration, thus negating the major costs of transporting CO_2 to a separate location and drilling new injection wells. Dissolving CO_2 in geothermal reinjectate also mitigates the buoyancy risk of supercritical free-phase CO_2. Sequestering biogenic CO_2 is a carbon negative process because it was originally absorbed from the atmosphere by the biomass feedstock. Finally, superheating geothermal production fluid with biomass could (1) improve the commercial prospects of low temperature geothermal resources (<160°C) or (2) help retrofit existing geothermal plants that operate below design capacity.

Geothermal-BECCS could improve the transition to renewables while offsetting emissions from hard to decarbonize industries. However, to be successful, geothermal-BECCS plants must demonstrate thermodynamic synergy and cost competitiveness as an electricity generation cycle.

This paper establishes the thermodynamic characteristics and early economic analysis of retrofitting a geothermal flash plant for geothermal-BECCS. We do this by considering steam superheating from a biomass boiler and CO_2 sequestration through in-line dissolution in the brine injection well. We discuss the effect of CO_2 price, feedstock price, and year of retrofit on the levelized cost of electricity (LCOE) and plant payback period. This helps us identify feasible retrofit conditions.

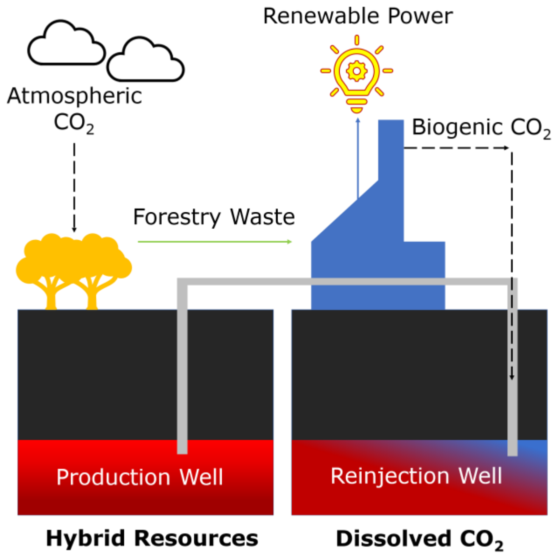

Figure 1: Process cycle schematic of a geothermal-BECCS system.

2. FUNDEMENTAL CONCEPTS OF GEOTHERMAL-BECCS

2.1 Hybrid Geothermal-Bioenergy Power

Pairing geothermal energy with a secondary energy source has been considered for almost one hundred years (DiPippo, 2016). The advantage of pairing geothermal energy with bioenergy over other resources such as fossil fuels or solar energy is that both are low carbon and non-intermittent sources of power. Forestry residues are a promising choice as a biomass feedstock as they are essentially a waste product from an ancillary industry.

Forestry residues can be expensive to transport as their energy content is lower per kilogram than coal, and thus their feasibility depends on local supply (Shabani et al., 2013). The low energy density can be especially problematic due to the varying moisture contents, harvest times and unpredictable feedstock quality. However, they can still be cost competitive under favourable economic conditions (IRENA, 2021).

A hybrid power case study for retrofitting the Rotokawa I geothermal plant in New Zealand considered the hypothetical insertion of a biomass boiler within the steam line between the cyclone separator and the back-pressure turbine (Thain & DiPippo, 2015). The superheated steam entering the turbine and advanced exhaust heat recovery after the turbine could theoretically have added a combined 8.5 MWe to the benchmark 29 MWe plant. Forestry residues from the Kaingaroa Forest were considered as the feedstock of choice due to their notable proximity to the geothermal resources in the Taupo Volcanic Zone (TVZ). The case study considered biogenic CO_2 emissions from the forestry residues as carbon neutral because the CO_2 was directly absorbed from the atmosphere within the life cycle of the feedstock.

Another case study at the Larderello geothermal field in Italy resulted in industry application of a geothermal-bioenergy hybrid plant (Dal Porto et al., 2016). A biomass boiler was implemented at the Cornia-2 power plant that was performing below design capacity. Dry steam and separated steam were mixed and superheated from 150°C to 370°C, adding 6 MWe to the plant's power production. Beyond the insertion of the boiler apparatus, the retrofit required minimal plant modifications to the turbine and valves (Dal Porto et al., 2016). Notably, the biomass feedstock was available from local suppliers and supported by a dedicated feed-in tariff with local government incentives. Thus, as long as the supply of feedstock is readily available and the two resources are collocated, geothermal-bioenergy hybrids could be economically feasible.

2.2 Carbon Capture and Storage in Geothermal Systems

Traditional carbon capture and sequestration (CCS) technologies involve the post combustion capture of CO_2 from fossil fuel power plants for geological storage (Galiègue & Laude, 2017). Storage of supercritical CO_2 entails high transport, injection and compression costs, tied to the market price of carbon, coupled with buoyancy and leakage risks (Kervévan et al., 2013). Additionally, a lack of sufficient economic incentives has made CCS difficult to implement on a world-wide scale (de Coninck et al., 2018).

At the CarbFix project in Iceland, geothermal-based CCS through in-line dissolution was originally pioneered to sequester magmatic origin CO_2 and, more recently, atmospheric CO_2. In-line dissolution consists of releasing CO_2 from an interior pipe within a geothermal reinjection column through a bubbler (Sigfússon et al., 2018). Because the solubility of CO_2 increases with elevated pressures (Duan & Sun, 2003), the rate of sequestration is improved for higher dissolution pressures. Carbonated water is also denser than standard geothermal brine, mitigating buoyancy risks as long as reservoir pressure is maintained (Sigfusson et al., 2015). Numerical simulations have shown that, with careful reservoir management strategies, the sequestered CO_2 remains dissolved (Kaya & Zarrouk, 2017). The main drawback of in-line dissolution is the limit of CO_2 solubility in geothermal brine, as any emissions beyond the sequestration capacity cannot be dissolved.

2.3 Bioenergy and Carbon Capture and Storage

Bioenergy and carbon capture and storage (BECCS) is an emerging technology where biogenic CO_2 emitted from feedstock combustion is captured and sequestered to create a potentially carbon-negative process. Because of this, BECCS has prominently featured in climate mitigation pathways (de Connick et al., 2018; Fridahl & Lehtveer, 2018). It is estimated that 3.3 – 7.5 $GtCO_2$ per year could be sequestered through BECCS technologies (Kemper, 2015).

A UK based study that considered forestry residues and other feedstocks for BECCS found that the LCOE of a 250 MWe plant ranged from NZD 320 to 426/MWh depending on capture method and feedstock (Emenike et al., 2020). This range was significantly higher than a benchmark bioenergy plant at the same capacity with LCOE of NZD 196 to 245/MWh. Finally, a study based in China found that a BECCS plant had an LCOE of NZD 267/MWh, far higher than a benchmark coal plant (NZD 76/MWh) and various configurations of cofiring biomass-coal plants with CCS (NZD 169 to 200/MWh) at the same capacity (Yang et al., 2021).

The global feasibility of BECCS is dependent on the price of carbon (Lehtveer & Emanuelsson, 2021*)*. Provided there is enough land use and supply for biomass, infrastructure costs for transport and injection also play a pivotal role (Kemper, 2015). BECCS is still an emerging technology with only a few case studies and practical applications around the world. In a European based study, BECCS became more economically feasible than conventional CCS at a carbon emissions allowance of NZD 37/tonne; the emissions allowance was roughly NZD 38/tonne at the time (Wei, 2020).

3. GEOTHERMAL-BECCS SYSTEMS MODEL METHODOLOGY

Geothermal-BECCS is the combination of geothermal and bioenergy for electricity production with aqueous capture of subsequent biogenic CO_2 through in-line dissolution. Coupling these core aspects together requires techno-economic modelling to (a) derive thermodynamic synergy, (b) quantify sequestration and (c) evaluate financial viability through key energy economic indicators. We have developed a systems model to determine the viability of retrofitting a flash plant into a geothermal-BECCS plant (Titus et al., 2022). A flash plant was chosen for this study because both biomass hybridization (Dal Porto et al., 2016) and in-line dissolution (Sigfusson et al., 2015) have independently been retrofitted in real-life settings. The key processes in the systems model are described below.

3.1 Thermodynamic Systems Model

We consider a retrofit scenario where a biomass boiler is applied between a steam receiver and steam turbine in a flash plant. The steam receiver is fed separated steam from two different production wells. In geothermal fields, wells may have varying downhole fluid temperatures (T_{DH}) depending on location and depth. In this study, T_{DH} was assumed to be 250°C for Well A and 200°C for Well B (Figure 2). The geofluid in the reservoirs was assumed to be saturated liquid. The temperature of each respective wellhead separator (T_{sep}) is determined by the optimal separator temperature method:

$$T_{sep} = \frac{T_{DH} + T_{Cond}}{2} \tag{1}$$

where T_{Cond} is the condenser temperature, set at 44°C (0.09 bar). The steam from both wells is collected from the steam receiver and the brine is dispatched to one brine injection well, with the mass-weighted average temperature calculated for each respective case.

In the benchmark flash plant, the steam is sent to the condensing turbine. In the geothermal-BECCS retrofit, the steam would enter the biomass boiler for superheating. The required heat of the boiler is dependent on the total mass flow rate of steam ($\dot{m}_s$), the enthalpy of incoming steam (h_s) and the intended enthalpy of outgoing superheated steam (h_{shs}). The latter correlates to the plant design temperature of superheated steam. Thus, from Thain & DiPippo (2015), the boiler heat required ($\dot{Q}_{shs}$) is:

$$\dot{Q}_{shs} = \dot{m}_s(h_{shs} - h_s) \tag{2}$$

To achieve this level of superheating, the required biomass burn rate ($\dot{m}_{bio}$) is calculated from the higher heating value of the biomass feedstock (HHV) and the efficiency of the biomass boiler (η_{Boiler}), assumed to be 80%. These values are both design parameters for the plant, with the higher heating value dependent on feedstock quality. The biomass burn rate is calculated from:

$$\dot{m}_{bio} = \frac{\dot{Q}_{shs}}{\eta_{Boiler} HHV} \tag{3}$$

The generated power of the geothermal-BECCS plant ($\dot{W}_g$) is calculated with the following equation:

$$\dot{W}_g = \dot{m}_s(h_{shs} - h_{ex,real}) \tag{4}$$

where $h_{ex,real}$ is the real turbine exhaust enthalpy of the steam condensate, found by incorporating the isentropic turbine exhaust enthalpy of steam condensate ($h_{ex,isen}$) and the dry turbine efficiency (η_{TD}) into the dry expansion equation (Janes, 1984):

$$h_{ex,real} = h_{shs} - \eta_{TD}(h_{shs} - h_{ex,isen}) \tag{5}$$

The dissolution pressure and bubbler depth for in-line dissolution were optimized to facilitate complete injection of biogenic CO_2. For the solubility of CO_2 in pure water, we used the chemical potential model of Duan and Sun (2003), which is a standard formulation used in geothermal-CO_2 reservoir simulators (Zyvoloski, 2007). In this formulation, solubility is parameterized as a function of pressure and temperature. We have previously checked that typical geothermal brine salinities do not appreciably reduce the solubility. From here, both gross emissions and negative emissions intensity can be determined (Titus et al., 2022). The parasitic pump compression load was then calculated to compress the CO_2 to dissolution pressure. The change in pressure across the compressor (ΔP_C) is calculated as follows:

$$\Delta P_C = P_{dis} - P_{ex} - \rho_{CO_2} g Z_{dis} \qquad (6)$$

where P_{dis} is the dissolution pressure at the bubbler, P_{ex} is the exit pressure of the CO_2 from the boiler (assumed to be 1 bar, 10^5 Pa), ρ_{CO_2} is the density of the CO_2 at the bubbler found through equations of state, g is the acceleration due to gravity and Z_{dis} is the bubbler depth. The specific compressor work (w_C) is given in kWe per kg of CO_2 and found with the following equation (Silla, 2003):

$$w_C = \left(\frac{k}{k-1}\right) R T_{CO_2} [\left(\frac{\Delta P_C}{P_{ex}}\right)^{\frac{k-1}{k}} - 1] \qquad (7)$$

Where k is a ratio of the specific heat of CO_2 at a constant pressure to the specific heat of CO_2 at a constant volume, R is the individual gas constant (J/kgK) and T_{CO_2} is the temperature of the CO_2 in Kelvin. These were assumed to be 1.28, 188.92 J/kgK and 313.15 K respectively.

3.2 Economic Systems Model

The thermodynamic viability and CDR potential of geothermal-BECCS plants must be considered within the wider context of electricity markets. The levelized cost of electricity ($LCOE$) is a useful economic indicator to compare the viability of a retrofitted geothermal-BECCS plant to the performance of the benchmark geothermal flash plant. $LCOE$ is defined as the unit cost of electricity generation divided by the total amount of generation in the plant's life (NZD/MWh). The $LCOE$ of geothermal-BECCS plants is dependent on the total upfront costs, the annual electricity generated, the annual CO_2 sequestered, OPEX costs for power generation and CDR, the plant gate costs of forestry residues and the price of CO_2. Because there are costs included for CDR, the $LCOE$ of geothermal-BECCS plants must factor the potential revenue of sequestering biogenic CO_2:

$$LCOE = \frac{NPV_{\text{cost}} - NPV_{\text{rCO}_2}}{NPV_{\text{electricity}}} \qquad (8)$$

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).

The plant's payback period is another useful financial metric. It is marked as the financial year when the net cash flow of the project (NCF) becomes positive. NCF is defined as the subtraction of cumulative, present value costs from revenue over the operation time of the plant.

$$NCF(n) = \sum_{i=1}^{n} Revenue - \sum_{i=1}^{n} Costs \qquad (9)$$

where n is the number of years that the plant has been operating. NCF is negative at n = 1 due to the CAPEX required to construct the plant. If the payback period happens when n < the plant life (~30 years), the project will eventually be profitable. If NCF doesn't reach zero before the final year of operation, the project cannot break even under the current economic conditions. Both payback period NCF are sensitive to the price of electricity on the wholesale market, which will vary for several reasons including the time of day and the makeup of the energy matrix. A fixed value of NZD 90/MWh was assumed for this study (Electric Authority NZ, 2022).

In this work, the primary economic parameters investigated were the price of CO_2 and the plant gate cost of forestry residues, which were assumed to be NZD 80/tonne and NZD 140/tonne (MPI, 2020), respectively in 2022. The price of CO_2 on the New Zealand ETS is projected to rise to NZD 160/tonne by 2035 (MBIE 2021). Assuming a specific density of wood waste of 1234 kg/m^3 (Nurek et al., 2019), a high harvesting cost of NZD 45/m^3 (MPI, 2020) and a low transport cost of NZD 39/tonne (MPI, 2020), a plant gate cost of NZD 70/tonne for forestry residues was assumed by 2035.

The CAPEX and OPEX rates for geothermal energy production were assumed to be NZD 6346/kWe (2021 weighted average of new plants) and NZD 183/kWe (IRENA, 2021), respectively. The CAPEX for geothermal power plants included exploration and field development costs. The biomass boiler was assumed to have a CAPEX rate of NZD 1000/kW (Windsor Energy, 2022), with an OPEX of 2% of the total CAPEX (IRENA, 2021). The CAPEX and OPEX rates of in-line dissolution were calculated as NZD 31/tonne and NZD 3.2/tonne of CO_2 sequestered respectively, based on the CarbFix project (Gunnarsson et al., 2018).

3.3 Geothermal-BECCS retrofit

Using the processes described in the above subsections, the techno-economic performance of a potential geothermal-BECCS retrofit plant was modelled and compared to a benchmark flash plant. The main comparison outputs between the two were net power, utilization efficiency, emissions intensity and LCOE. The benchmark flash plant consists of two production wells with wellhead separators, a steam receiver, a turbine, a direct contact condenser, a natural draught cooling tower, one brine injection well and one condensate well.

Well A had a downhole geofluid temperature of 250°C and Well B had a geofluid temperature of 200°C. Both wells produced 50 kg/s of geofluid, within the standard range of geothermal production well (DiPippo, 2016), totaling 100 kg/s. This allows the results to be scaled by adding pairs of production wells. The condenser temperature was 44°C (0.09 bar), and the respective wellhead separator pressures were optimized based on Eqn. 1.

A pure water model is used for simplicity in this theoretical configuration. In Titus et al. (2022), we show that the effects of magmatic origin CO_2 and dissolved minerals are negligible for New Zealand's geothermal fields. These are site specific and can be integrated into the systems model for analysis of an actual geothermal field.

For the economic modelling, year zero is the financial entry point where the only cost is the upfront investment cost. Construction is assumed to take one year, with the plant producing electricity by year two. The plant then operates until year 30, the conventional life of a geothermal power station. A fixed electricity price of NZD 90/MWh was used in this study, analogous to baseload prices on the New Zealand wholesale electricity market in 2022 (Electric Authority NZ, 2022).

The geothermal-BECCS retrofit had a similar configuration as the benchmark plant, but with the inclusion of a biomass boiler between the steam receiver and the turbine, and in-line dissolution of biogenic CO_2 in the brine reinjection well (Figure 2). The retrofit investment cost, made up by the biomass boiler and in-line dissolution assets, included a standard 10% contingency (IRENA, 2021). The CO_2 emissions factor for forestry residues was assumed to be 0.862 kg of CO_2 per kg of biomass (NZ Bioenergy Association, 2019).

For a given geothermal-BECCS system, the amount of biomass required for superheating is dependent on the temperature difference between the reservoir fluid, which is site specific, and the final superheat temperature, which is a design parameter of the plant. Because geofluid, not distilled water, is being superheated, corrosion of equipment must be kept in mind when deciding the final superheated steam temperature (Dal Porto, 2016). For this study, we assumed a final superheated steam temperature of 400°C, closer to the superheated steam temperature at Cornia-2 than a traditional thermal power station (Kestin et al., 1978).

As a first point of analysis, year six was chosen as the retrofit year. This meant that from year two to year five, the plant operated the exact same as the benchmark. From year seven, the plant generated electricity using 400°C superheated steam, incurred a fuel cost for the required biomass burn rate, and received revenue from CDR. The OPEX was also updated to reflect the operation of the boiler and in-line dissolution. A parasitic load for compressing the CO_2 to the optimized dissolution pressure was introduced from this year as well (Eqn. 6 & 7). To account for the retrofit year, the plant life is extended to 31 years.

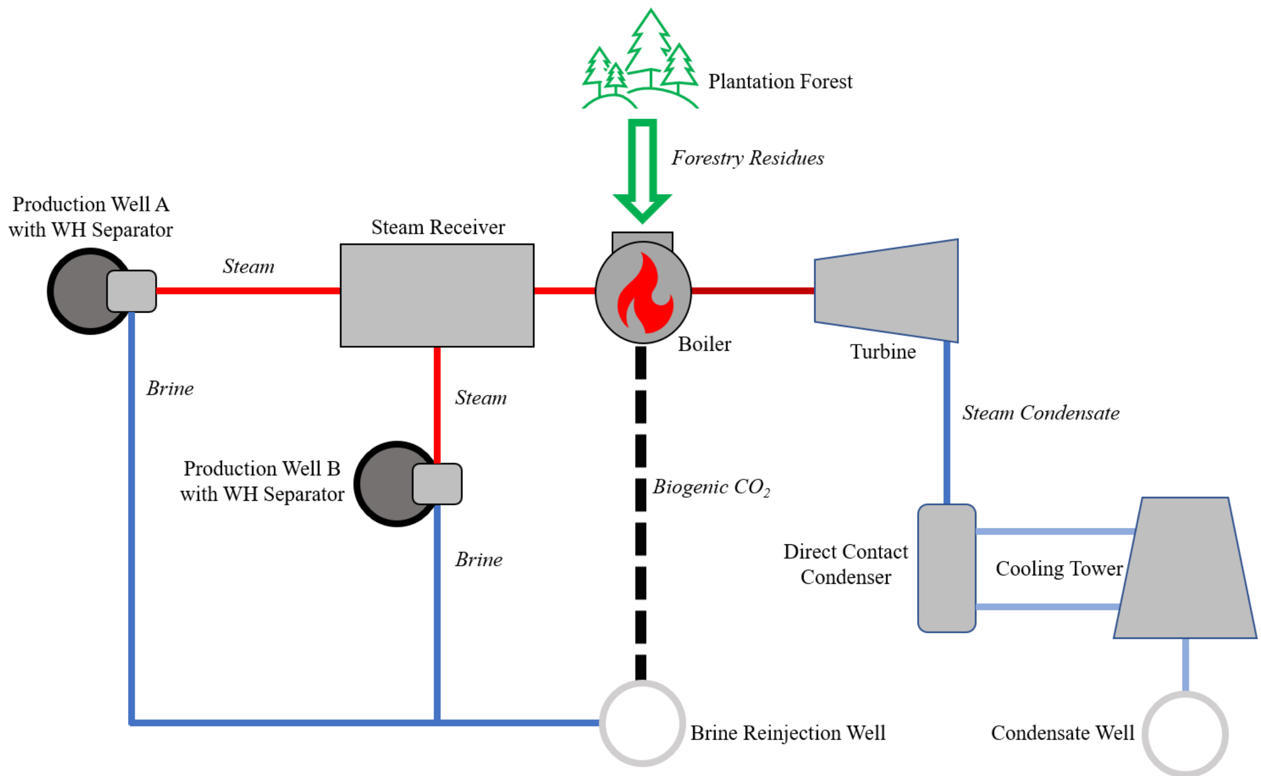

Figure 2: Systems model schematic of geothermal-BECCS retrofit flash plant.

Only the brine injection well was considered for CDR because of the oxygen exposure to the condensate from the direct contact condenser and cooling tower, a source of severe corrosion for magmatic CO_2 reinjection in the past (Bonafin et al., 2019). This results in less overall mass for sequestration capacity than initially produced by the two production wells.

The plant is assumed to be located in the TVZ and collocated with forestry operations such that the transport cost was NZD 89/tonne for forestry residues (MPI, 2020) and total plant gate cost was NZD 140/tonne in 2022 (including a 10% contingency). For 2035, transport costs were assumed to be on the low estimate of NZD 35/tonne (MPI, 2020), resulting in a total plant gate cost of NZD 70/tonne (no contingency). The price of CO_2 on the New Zealand ETS was NZD 80/tonne in 2022, and projected to rise to NZD 160/tonne by 2035 (MBIE, 2020).

Additionally, the sensitivity of LCOE and payback period was analysed from a range of potential values for the price of CO_2 (NZD 40 – 250/tonne) and the price of forestry residues (NZD 40 – 200/tonne). The effect of changing the retrofit year was also investigated on LCOE and payback period for the 2022 and 2035 market condition. For this study, three different HHVs of forestry waste were tested: 15000 kJ/kg, 18000 kJ/kg, and 24000 kJ/kg as low (bagasse), medium (switchgrass) and high (pine) energy density feedstocks respectively (Ciolkosz, 2010). It should be noted that a higher HHV will result in a lower biomass burn rate, and by extension, lower biogenic CO_2 emissions. No other taxes or incentives where included in this analysis.

4. RESULTS AND DISCUSSION

The results of the benchmark geothermal flash plant and the retrofitted geothermal-BECCS plant are summarised in Table 1. Because the biomass boiler is inserted between the steam receiver and the turbine, the total mass of steam and brine remain constant at 18.8 and 81.2 kg/s, respectively. For the benchmark plant, the steam entered the turbine at roughly 135°C, resulting in a net power of 6.8 MWe and utilization efficiency of 16.1%. The LCOE of the benchmark plant was NZD 94/MWh and independent of any forestry residue or CO_2 market trends.

There were different outcomes for the geothermal-BECCS retrofit plant depending on the energy density of the forestry residues. For the low-density fuel (15000 kJ/kg), superheating the steam from 135°C to 400°C required 27 kt of biomass per year, resulting in 23.7 kt of biogenic CO_2 sequestered. This led to an increased net power and utilization efficiency of 10.3 MWe and 18.4%, respectively after CO_2 compression load was factored in to compress the CO_2 to 23 bar. In 2022, the price of CO_2 on the ETS wouldn't provide enough revenue to offset the high costs incurred by the feedstock inputs.

For the medium-density fuel case (18000 kJ/kg), the required biomass burn rate was 22.5 kt per year and the total CO_2 sequestered was 19.8 kt per year and generated 10.3 MWe. The lower biomass burn rate resulted in a higher utilization efficiency (19.3%). The LCOE was also lower (NZD 111/MWh), but still above the base geothermal plant for 2022 conditions.

Table 1: Techno-Economic Systems Model Results for Benchmark and Geothermal-BECCS retrofitted at year six, with low (15000 kJ/kg), medium (18000 kJ/kg), and high (24000 kJ/kg) density biomass feedstock

	Benchmark Flash Plant	Geothermal-BECCS Retrofit Plant		
		15000 kJ/kg	18000 kJ/kg	24000 kJ/kg
Total Steam Mass (kg/s)	18.8	18.8	18.8	18.8
Total Brine Mass (kg/s)	81.2	81.2	81.2	81.2
Turbine Inlet Temperature (°C)	135	400	400	400
Biomass Burn Rate (kt/year)	0	27	22.5	16.9
Sequestered CO_2 (kt/year)	0	23.7	19.8	14.8
Dissolution Pressure (Bar)	0	23	19	14
Net Power (MWe)	6.8	10.3	10.3	10.4
Emissions Intensity (gCO_2/kWh)	0	-263	-218	-163
Utilization Efficiency (%)	16.1	18.4	19.3	20.5

LCOE - 2022 Conditions (NZD/MWh)	94	114	111	107
LCOE - 2035 Ideal (NZD/MWh)	94	82	84	87

For the high-density fuel (24000 kJ/kg), the biomass burn rate and CO_2 sequestration were the lowest of all configurations at 16.9 kt per year and 14.8 kt per year, respectively. The dissolution pressure was 14 bar, with the highest net power at 10.4 MWe. The plant also had a utilization efficiency of 20.5%, a 25% increase over the benchmark plant. However, with an LCOE of NZD 107/MWh, the fuel costs were still too high to allow competition with the benchmark plant in 2022.

The change in LCOE with respect to retrofit year for 2022 conditions of feedstock and carbon price is displayed in Figure 3, where each coloured line corresponds to the energy density of the biomass used for combustion at the geothermal-BECCS plant. All three energy-density fuel configurations converge at the 30-year mark at the benchmark plant LCOE of NZD 94/MWh (Figure 3). This means that the fuel costs of NZD 140/tonne are too high to justify transitioning to geothermal-BECCS. In other words, the revenues from CDR and boosted electricity generation are unable to offset these costs. At a wholesale electricity price of NZD 90/MWh, neither the benchmark plant or geothermal-BECCS plant are able to break even within the plant life.

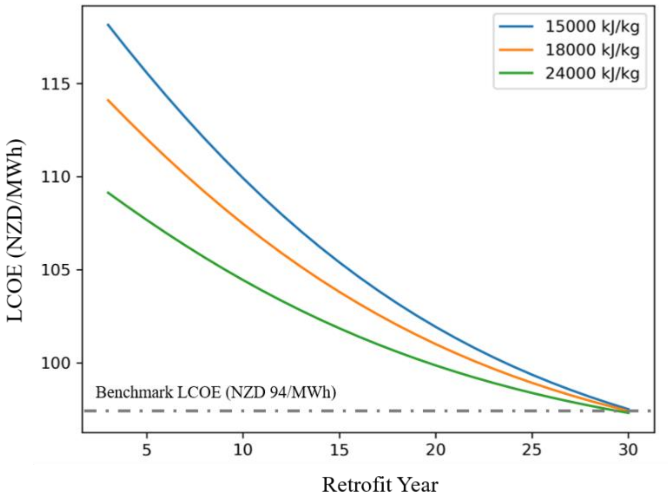

Figure 3: LCOE of geothermal-BECCS plants based on retrofit year for 2022 market conditions.

There is a change in outcomes when considering the projected 2035 market conditions. With the reduced feedstock cost of NZD 70/tonne and the expected increase in CO_2 price to NZD 160/tonne, all three energy density configurations of geothermal-BECCS are more cost competitive than the benchmark geothermal plant (Figure 4).

The LCOE values of the geothermal-BECCS configurations, retrofitted at year six, are NZD 82/MWh (15000 kJ/kg), NZD 84/MWh (18000 kJ/kg) and NZD 87/MWh (24000 kJ/kg). The revenues incurred from the higher CO_2 price now outweigh the fuel costs to the point where the configuration with the most biomass burned and gross CO_2 sequestered is the most cost competitive, despite a higher compression load and slightly lower power output.

Figure 4a shows that retrofitting the plant earlier (up to year 3) can further lower the LCOE of the respective energy density configurations. The low-density configuration also has the longest range of possible years to retrofit for the plant to break even within its life cycle, with the last possible year being year 15 to break even at year 31 (Figure 4b).

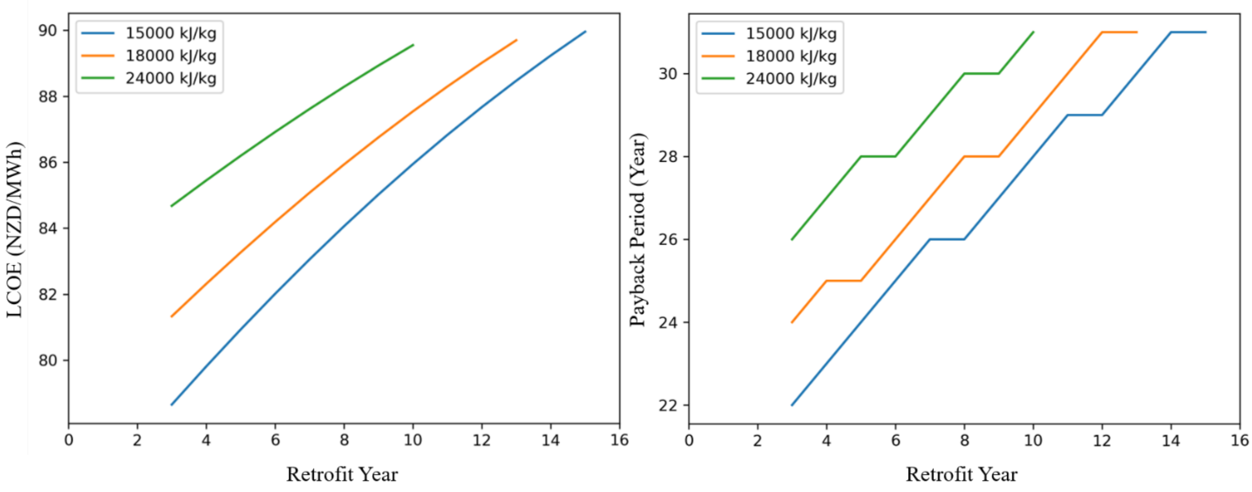

Figure 4: LCOE (right) and payback period (left) of geothermal-BECCS plants based on retrofit year for 2035 market conditions. Note that, counterintuitively, LCOE and payback are more attractive for low-energy fuels because these generate larger sequestration revenues per kWh.

As the precise combination of fuel cost and CO_2 price in the future is unknown, we have performed a sensitivity analysis for these two variables. This is a useful step to discern the conditions for which retrofitting an existing flash plant into geothermal-BECCS becomes feasible. Figure 5 shows a contour plot for LCOE and payback period for the low-density fuel configuration. If the price of CO_2 increased from NZD 80/tonne to NZD 160/tonne with no reduction in fuel cost, then the plant would still not be able to break even by year 30.

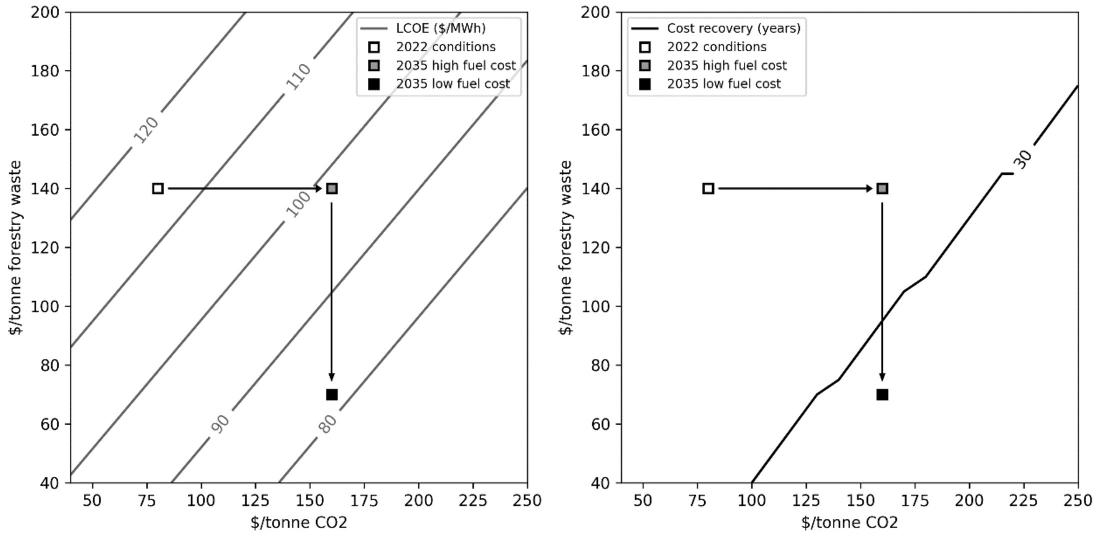

Figure 5: Sensitivity plot of LCOE (right) and payback period (left) for low-density configuration (15000 kJ/kg), retrofitted at year 6.

However, the feedstock cost doesn't need to decrease to NZD 70/tonne at the 2035 CO_2 price to cross the breakeven threshold (Figure 5b); around NZD 90/tonne is enough. If the price of CO_2 increased to NZD 250/tonne, then retrofitting the plant at year 6 would still be viable with no change in the feedstock cost. A similar trend can be observed in the medium-density (Figure 6) and high-density (Figure 7) configurations, although they are less sensitive to the price of CO_2 due to the overall lower amount of CO_2 sequestered per year.

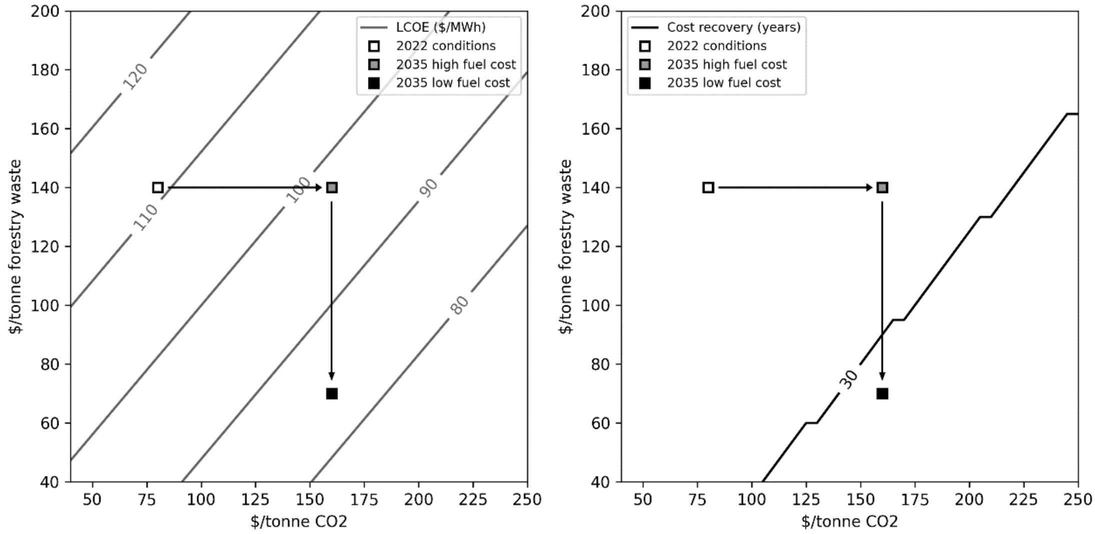

Figure 6: Sensitivity plot of LCOE (right) and payback period (left) for medium-density configuration (18000 kJ/kg), retrofitted at year 6.

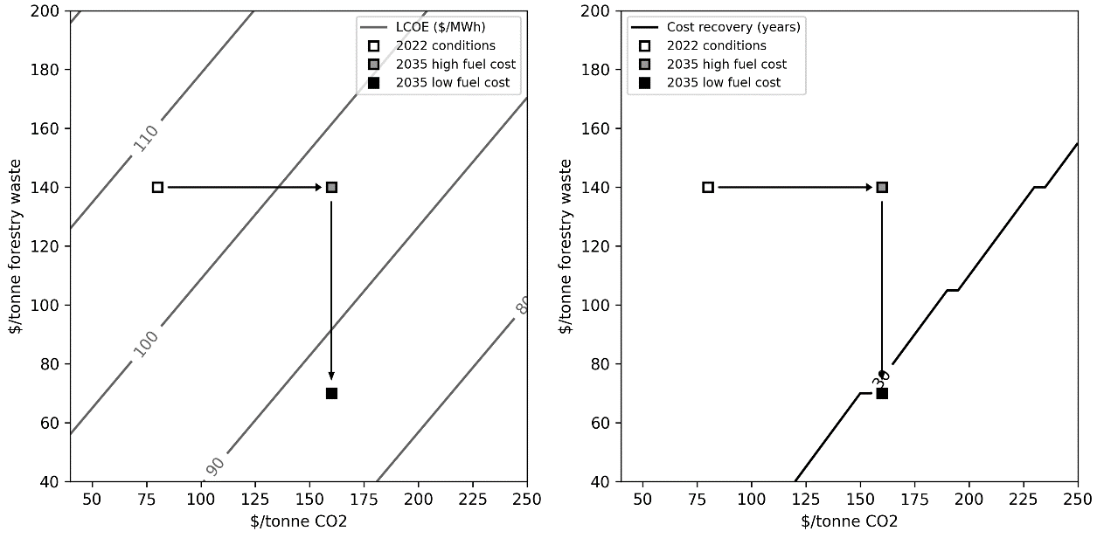

Figure 7: Sensitivity plot of LCOE (right) and payback period (left) for high-density configuration (24000 kJ/kg), retrofitted at year 6.

Even within the context of 2022, the modelled geothermal-BECCS configurations had lower LCOE values than in conventional BECCS studies. The LCOE values of previously studied BECCS configurations ranged from NZD 267 to 426/MWh (Emenike et al., 2020, Yang et al., 2021) compared to geothermal-BECCS at NZD 107 to 114/MWh. Another metric, the levelized cost of sequestration (LCOS) could be useful to further compare geothermal-BECCS to conventional BECCS and other negative emissions technologies like geothermal-DACCS. Additionally, the levelized cost of carbon abatement (LCCA) could illustrate how cost effective the combined aspects of geothermal-BECCS (boosted renewable power and negative emissions) are at overall decarbonisation (Friedmann et al., 2020).

With the effect of different techno-economic parameters on the economic viability of geothermal-BECCS established, the logical next step for future work is to determine a global inventory of geothermal-BECCS potential. This inventory could allow for strategic retrofit opportunities at real world geothermal sites. Furthermore, better understanding of local market conditions would bridge the gap between climate policy targets and commercial applications of carbon dioxide removal. Additionally, more detailed costing information or correlations can be used to optimize individual apparatus'.

Different geothermal sites would require specific considerations. In all configurations listed in this work, there remains a high exhaust enthalpy of the steam condensate in geothermal-BECCS plants. Thus, advanced heat recovery systems might be useful to further improve efficiency and lower cooling load. Geothermal plants using surface (indirect) condensers could also use condensate wells for biogenic CO_2 injection without concern for oxygen corrosion since there is no contact with air.

The feasibility of different feedstocks, such as agricultural residues or energy crops, can also be examined. With regards to the transportation of feedstock, a full life cycle assessment may be necessary to ensure that emissions remain carbon negative. Thus, areas with collocated geothermal resources and available feedstocks should be targeted first.

A more comprehensive representation of the wholesale electricity market could also be integrated into the model to provide more nuanced sensitivity analysis of the key economic indicators. Future policy and economic incentives for CDR can also be included in the model. Finally, this work can be extrapolated to the assessment of binary plant retrofits.

5. CONCLUSION

In conclusion, early techno-economic analysis shows that retrofitting geothermal flash plants for BECCS operations can be more cost competitive than conventional BECCS plants, even in 2022. There are several notable advantages of geothermal-BECCS over base geothermal plants, including boosted renewable power, improved utilization efficiency and the potential to effectively remove CO_2 from the atmosphere.

The geothermal-BECCS retrofit configurations were able to provide roughly 10 MWe of additional power and offset between 39 to 64% of the CO_2 emissions rate of natural gas plants. However, the market conditions must be such that the cost of feedstock is not too prohibitive and that there are clear economic incentives for CDR.

As of 2022, the geothermal-BECCS retrofit had LCOE values of NZD 114/MWh for feedstock with a HHV of 15000 kJ/kg, NZD 111/MWh for feedstock with a HHV of 18000 kJ/kg, and NZD 107/MWh for feedstock with a HHV of 24000 kJ/kg. While these surpassed conventional BECCS plants (NZD 267 – 420/MWh), it would not compete with the benchmark geothermal plant at NZD 94/MWh.

For projected 2035 conditions, the geothermal-BECCS retrofits become more favourable to the benchmark plant, with LCOEs of NZD 82-87 MWh. It was found that retrofitting the plant as early as possible further lowered LCOE and payback period. With these conditions, the price of CO_2 was high enough that sequestering a higher amount become more beneficial, and notably it was the low-energy density configuration that proved to be more cost effective despite requiring more fuel and compression power. Thus, given the right market conditions, and potential future policy incentives, it could be financially viable to retrofit flash plants to geothermal-BECCS, achieving net-negative emissions electricity generation.

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