JOURNAL OF THE ROYAL SOCIETY OF NEW ZEALAND
2025, VOL. 55, NO. 4, 893–911
https://doi.org/10.1080/03036758.2024.2385807

RESEARCH ARTICLE

From carbon neutral to carbon negative: a theoretical bioenergy and CO_2 removal retrofit at Ngāwhā geothermal power station

Karan Titus [a], David Dempsey[a], Rebecca Peer [a] and Fabian Hanik[b]

[a]The University of Canterbury, Christchurch, New Zealand; [b]Ngāwhā Generation Ltd, Ngāwhā Springs, New Zealand

ABSTRACT

For countries like New Zealand with high renewable electricity generation (≥80%) but large emissions per capita, traditional decarbonisation methods are limited or costly. However, carbon dioxide removal (CDR) technologies can drive multiple sectors of the economy across the net-zero barrier through negative CO_2 emissions. We argue that the key to scaling up CDR begins with the preponderance of New Zealand's geothermal and biomass resources. New Zealand has a proud and innovative history with geothermal energy, currently producing ~20% of the country's electricity. Modern advances in geothermal energy have demonstrated that it is peerless amongst renewable energy-sources in the ability to facilitate onsite CDR by repurposing existing wells. We examine a theoretical bioenergy retrofit at the Ngāwhā geothermal plant to increase capacity by 1 MWe, with as much biogenic CO_2 as permissible dissolved in reinjectate. Forestry residues are the feedstock of choice due to their abundance in the Far North. We show that up to 15.9 $ktCO_2$/year can be removed effectively from the atmosphere. Only 6% of the Far North's forestry residues are required to achieve this. Under 2024s emissions trading scheme (ETS), the annual revenue of CDR ($0.79 million) could exceed that of new electricity ($0.47 million).

ARTICLE HISTORY
Received 27 February 2024
Accepted 22 July 2024

HANDLING EDITOR
Aiguo Hu

KEYWORDS
Geothermal; bioenergy; CO_2; CDR; retrofit; energy economics

Introduction

The worldwide deadline for rapid decarbonisation to mitigate anthropogenic climate change is fast approaching. Approximately 4% of global CO_2 emissions need to be cut each consecutive year to reach net zero by 2050 (IPCC 2023). However, by the end of 2020 two-thirds of fossil fuel companies had produced beyond their production budget for international climate targets (Rekker et al. 2023). The next two decades will require a two-pronged approach to avoid overshoot: robust adoption of renewable energy and deployment of CO_2 removal technologies.

CONTACT Karan Titus karan.titus@pg.canterbury.ac.nz

For a small country, New Zealand has long been a global leader in renewable electricity generation. For example, New Zealand has ≥80% penetration of renewable energy in the electricity sector (MBIE 2021). Up to 20% of that renewable electricity comes from geothermal energy. In fact, New Zealand has the fifth highest installed capacity of geothermal energy in the world at ∼ 1 GWe (Schneider and Richter 2020).

However, New Zealand has one of the highest CO_2 emissions per capita (Scott 2022; Wang et al. 2022), ranking in the top five of members of the Organisation for Economic Co-operation and Development (OECD). Much of these emissions come from the agricultural sector (Coriolis 2023), an industry difficult to decarbonise with renewable electricity alone.

This is where the second prong of climate change mitigation, carbon dioxide removal (CDR), becomes important. CDR refers to engineered or nature-based activities that remove CO_2 from the atmosphere and durably store it via terrestrial, marine, biological or geological means (Minx et al. 2018). Thus, from a carbon accounting perspective, CDR differs from the point-source capture of fossil emissions. In this study, we propose the combination of geothermal, bioenergy and CDR to enable an energy cycle that results in net negative CO_2 emissions. We investigate the techno-economic feasibility of this concept via retrofit of Ngāwhā power station. All monetary values are presented in US dollars ($).

We argue that there are certain synergies to leverage that could make this technology an effective inclusion to New Zealand's wider energy matrix. Geothermal power plants operating below design capacity can be boosted by bioenergy hybridisation (Dal Porto et al. 2016). Bioenergy also allows surface-based enthalpy controls for cold wells or geothermal fields that have reached their consent limits. Post-combustion, biogenic CO_2 is carbon neutral (Lehtveer and Emanuelsson 2021), and is therefore valuable to facilitate net-negative emissions through geological storage. Alternatively, it can be utilised in industrial or horticultural processes as an alternative to fossil CO_2. Finally, the dissolution of atmospheric CO_2 in geothermal reinjectate for permanent geological storage has been demonstrated overseas (Ratouis et al. 2022).

As of 2023, New Zealand's only negative emissions strategy is afforestation. With the adoption of combined geothermal-bioenergy-CDR, New Zealand could be an early adopter of negative emissions technologies and share its expertise globally, as it has done with conventional geothermal energy in the past (Steff 2019).

Geothermal energy with CO_2 removal

Geothermal production fluid contains non-condensable gasses (NCGs) such as H_2S and CO_2 dissolved in solution (McLean et al. 2020). These NCGs effervesce from geothermal fluid during temperature decreases in the power production process, such as at condensers and heat exchangers. The presence of NCGs in condensers can increase the overall condenser pressure, lowering the power produced by the geothermal turbine. Thus, they have traditionally been vented to the atmosphere to avoid accumulation in the power plant apparatus. From a carbon accounting standpoint, the CO_2 component of a geothermal plant's emissions will proportionally increase the net concentration of CO_2 in the atmosphere.

Although the emissions intensity (EI) of CO_2 from geothermal power plants in New Zealand is on average far lower than fossil fuel-based power plants (75 gCO_2/kWh for geothermal vs. 400–1000 gCO_2/kWh for fossil alternatives; McLean et al. 2020), it still presents an environmental concern and financial liability under emissions trading legislation.

The process of re-dissolving NCGs in geothermal injection fluid, thereby avoiding CO_2 emissions entirely, was first pioneered at the Hellisheidi geothermal power plant in Iceland (Gunnarsson et al. 2018; Ratouis et al. 2022) as part of the Carbfix project. Since then, the project has expanded to include direct air capture of CO_2. A pilot plant was installed in 2017 that captures 50 tCO_2/year from ambient air and dissolves it in injectate whereupon it mineralises underground in basalt formations.

In a similar process, the CO_2-dissolved project in France considered the dissolution of CO_2 from ethanol production into geothermal brine (Kervévan et al. 2017). Additionally, Titus et al. (2023a) showed that the combination of geothermal with bioenergy and carbon capture and sequestration (BECCS) could result in increased renewable electricity and net negative emissions. Negative emissions can be considered an additional revenue stream if the biogenic CO_2 removed is monetizable, thus lowering the cost of electricity production.

Theoretical new builds for geothermal-BECCS have also been compared to geothermal with direct air capture (DAC) for high temperature geothermal systems (>270°C). Under these conditions, Titus et al. (2023b) concluded that geothermal-BECCS outperformed geothermal-DAC economically due to the former's increase in renewable electricity production over the latter.

The prospect of monetising CDR and increasing renewable electricity production (via surface enthalpy control) could be valuable to geothermal plant operators. Furthermore, strategic implementation of low-cost CDR technologies can help strengthen decarbonisation efforts (IPCC 2023). In this study, we consider pairing geothermal, bioenergy and CDR for a possible carbon-negative retrofit solution at New Zealand's first carbon neutral geothermal plant.

Ngāwhā geothermal plant background

Using technology similar to what's described in Section 1.1, the Ngāwhā power station made history in 2023 to become the first carbon neutral geothermal plant in New Zealand. Thus, we select Ngāwhā for this carbon negative case study because (geogenic) CO_2 injection infrastructure already exists at site and is techno-economically feasible.

Located in the Far North, the Ngāwhā geothermal field is the only major geothermal system in New Zealand situated outside the TVZ (Figure 1). This field is operated by Ngāwhā Generation Ltd which is owned by Top Energy Group. The Ngāwhā geothermal power plant (57 MWe) is comprised of four Ormat Energy Converter (OEC) binary units, producing ~450 GWh per year. The first pair of these, OEC1 & OEC2, are referred to as Station-1 and began production in 1998. We limit the theoretical carbon negative retrofit to Station-1 because of its well-known production/injection history and its current generator can handle an additional ~2 MW (before accounting for parasitic loads).

Production wells feeding into Station-1 tap into a liquid-dominated reservoir at 230°C. Two-phase fluid is flashed in a horizontal separator (Figure 2A) at ~14.5 bar. The

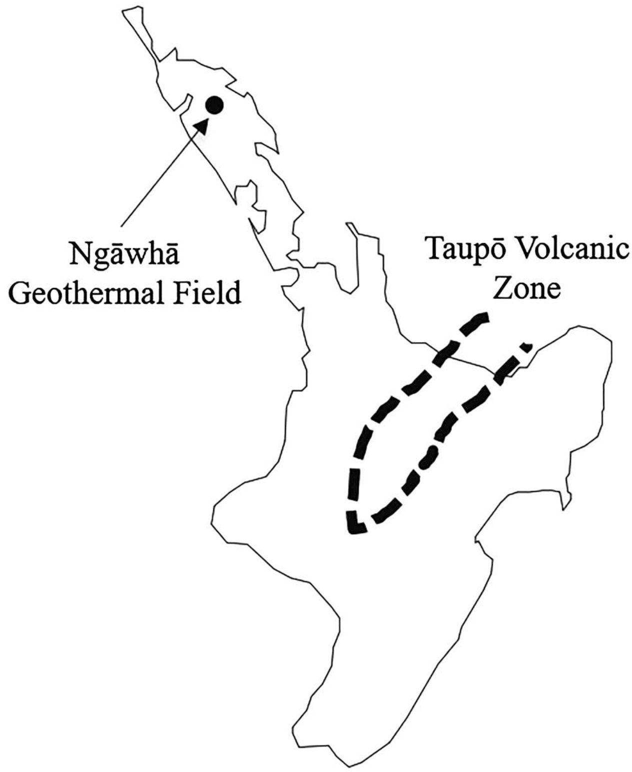

Figure 1. location of the Ngāwhā geothermal plant and the Taupō Volcanic Zone (TVZ) in the North Island of New Zealand. Not to scale.

geothermal steam and brine pass through a vaporiser and evaporator, respectively, where they transfer thermal energy to n-pentane. The n-pentane then completes a closed-loop organic Rankine cycle where a turbine is rotated to generate electricity. The cooled geothermal fluid is then combined into a single stream and dispatched to the injection well. A simplified process schematic is presented in Figure 2D.

To transition Ngāwhā power station from carbon neutral to carbon negative atmospheric or biogenic CO_2 must also be injected concurrently with geogenic CO_2. The latter is the focus of this study due to intrinsic synergies between geothermal and bioenergy and the abundance of forestry waste for feedstock in the Far North.

Geothermal-bioenergy hybrids

Providing they are co-located, bioenergy synergizes well with geothermal energy because both are renewable, low-carbon and non-intermittent (Thain and DiPippo 2015; Dal Porto et al. 2016). In 2015, a case study investigating bioenergy hybridisation of the Rotokawa I geothermal power plant (29 MWe) concluded that an increase of 8.5 MWe was possible over the base plant (Thain and DiPippo 2015). The design considered the insertion of a biomass boiler in between the cyclone separator and the back-pressure steam turbine to increase the temperature and enthalpy of separated geothermal steam.

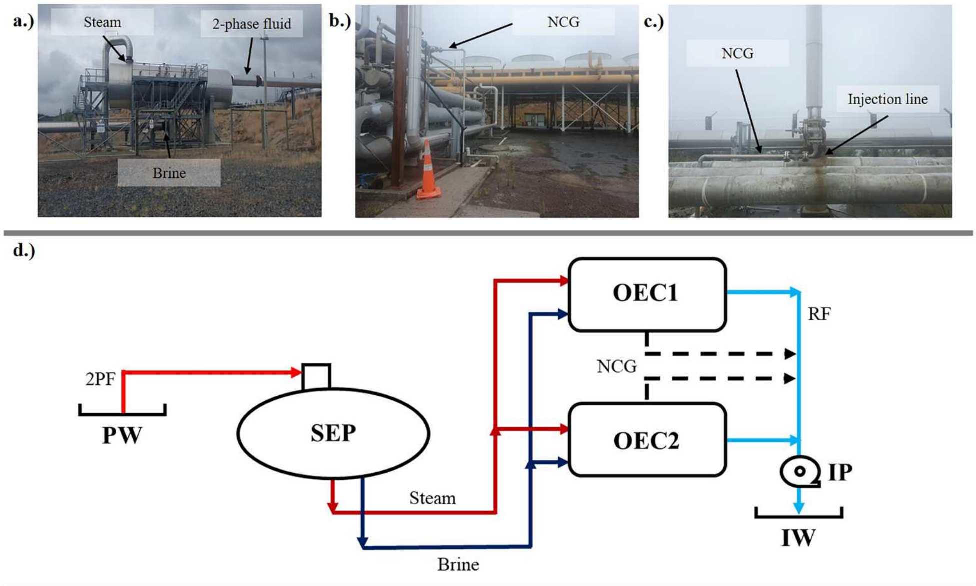

Figure 2. Overview of NCG reinjection at Station-1 at Ngāwhā geothermal plant – **A**, horizontal separator receiving two-phase geothermal fluid, **B**, NCG extraction from heat exchangers, **C**, NCG disposal into injection line carrying spent geothermal fluid, and **D**, process schematic of Station-1. PW = production well, SEP = vertical separator, OEC = Ormat Energy Converter unit, IP = injection pump, IW = injection well. Red line = two-phase geothermal fluid (2PF), dark red line = steam, dark blue line = brine, blue line = reinjection fluid (RF), dotted black line = non-condensable gasses (NCG).

Because Rotokawa I is situated within the Taupō Volcanic Zone (TVZ), the Kaingaroa Forest was the proposed source of the woody biomass (Thain and DiPippo 2015).

In 2016, an industrial application of a geothermal-bioenergy hybrid was implemented at the Larderello geothermal field in Italy (Dal Porto et al. 2016). The existing geothermal power plant, Cornia-2 (operated by Enel Green Power), was designed to operate at 20 MWe but failed to meet this capacity due to the relatively low temperature of steam (~150°C) fed to the turbine. Thus, a biomass boiler was inserted before the turbine to superheat the geothermal steam to 370°C, adding 6 MWe of power (Dal Porto et al. 2016).

Importantly, the Cornia-2 retrofit was reported to require minimal modifications. New infrastructure included only the boiler and heat exchanger apparatus and flue-gas lines (Dal Porto et al. 2016). In addition to these, modifications to the existing geothermal infrastructure were limited to the steam turbine and valves. Woody biomass feedstock was supplied locally and the retrofit was considered financially viable. Geothermal-bioenergy retrofits have also been considered for binary plants, combined heat and power applications and integration with ground-sourced heat pumps (Toselli et al. 2019; Zhang et al. 2019).

Notably, in the aforementioned hybrid examples, biogenic CO_2 was discarded into the atmosphere as a carbon-neutral by-product. Thus, this retrofit case study is novel because it is the first to consider geothermal-bioenergy hybrid configurations that result in net-negative emissions via CO_2 dissolution in geothermal reinjectate. Additionally, the potential to utilise biogenic CO_2 instead of fossil-based CO_2 is a valuable prospect for New Zealand's food, horticulture and aviation industries.

Materials and methods

Any theoretical retrofit of a geothermal power plant comes with opportunity costs. Understanding these costs is critical to decision making; therefore operators, stakeholders and policymakers should be given the tools to weigh different configurations in equivalent terms. We use the Titus et al. (2023a) thermodynamic systems model to chart the techno-economic feasibility of geothermal-bioenergy-CDR varied across several key parameters (Section 2.2, Table 4). A brief overview of the major processes is given in Table 1. A list of abbreviations is given in Table 2.

For a given geothermal system and selection of biomass feedstock, the major model outputs are net power (MWe), CDR rate ($ktCO_2$/year), the levelised cost of electricity (LCOE, \$/MWh) and levelised cost of sequestration (LCOS, \$/tCO_2). This allows for new geothermal-bioenergy-CDR configurations to be compared in equivalent terms to other electricity generation and CO_2 removal technologies.

We adjust LCOE and LCOS for retrofit configurations to represent only the cost to produce new electricity and remove CO_2. The levelised cost of new electricity (*LCNE*) relates all retrofit costs to the revenue of CDR removal in \$/MWh, and is calculated as follows:

$$LCNE = \frac{C_{\mathrm{new}} - R_{\mathrm{BioCO_2}}}{G_{\mathrm{new}}} \tag{1}$$

where C_{new} is the net present value (NPV) of all retrofit costs (CAPEX, OPEX, biomass

Table 1. Titus et al. (2023b) model overview for combined geothermal-bioenergy-CDR.

Process description	Model calculation
Conservation of mass and energy at a separator (DiPippo 2016)	$\dot{m}_s = \dot{m}_{\mathrm{geo}}(h_{\mathrm{geo}} - h_b)/(h_s - h_b))$
The thermal energy and biomass feedstock required from a biomass boiler to superheat separated steam (Thain and DiPippo 2015)	$\dot{m}_{\mathrm{bio}} = \frac{\dot{m}_s(h_{\mathrm{shs}} - h_s)}{\eta_{\mathrm{Boiler}} HV}$
The work generated by dry expansion of superheated steam in a turbine (Janes 1984)	$\dot{W}_g = \dot{m}_s[h_s - h_{\mathrm{shs}} - \eta_{TD}(h_{\mathrm{shs}} - h_{\mathrm{ex,isen}})]$
The biogenic CO_2 emissions based on the feedstock emissivity and biomass burn rate (Puettmann et al. 2020)	$\dot{m}_{CO_2} = X_{CO_2}\dot{m}_{\mathrm{bio}}$
The brine carrying capacity for biogenic CO_2 as a function of dissolution pressure, temperature and brine mass flow rate (Zyvoloski 2007)	$s_{CO_2} = f(P_{\mathrm{dis}}, T_{\mathrm{dis}})$ $\dot{m}_{\mathrm{dis}} = \dot{m}_b f(P_{\mathrm{dis}}, T_{\mathrm{dis}})$
The emissions intensity of the overall process, expressed in gCO_2/kWh (Friedmann et al. 2020)	$EI = \frac{E_{\mathrm{geo}} + E_{\mathrm{tran}} - E_{\mathrm{CDR}}}{G}$
The levelised cost of electricity, factoring the total costs and the revenues of simultaneous CO_2 removal (Titus et al. 2023b)	$LCOE = \frac{C - R_{CO_2}}{G}$
The levelised cost of sequestration, factoring the total costs and the revenues of simultaneous electricity generation (Titus et al. 2023b)	$LCOS = \frac{C - R_g}{E}$

$\dot{m}$ = mass rate [kg/s] with subscripts denoting steam (s), brine (b), two-phase mix at the wellhead (wh), biomass fuel (bio), total (CO_2) and dissolvable carbon dioxide (dis). h = specific enthalpy [kJ/kg] with additional subscripts denoting superheated steam (shs) and exhaust following isenthalpic expansion (ex, isen). η = efficiency of biomass heating (Boiler) and turbine expansion (TD). HV = heating value [kJ/kg]. s_{CO_2} = solubility of CO_2 in water, a function of pressure (P) and temperature (T). Annual emissions (converted to grams) calculated using geogenic emissions (E_{geo}), transportation emissions (E_{tran}) and carbon removed (E_{CDR}) with annual plant generation (G) given in kWh. Costs (C) are related to revenues (R) for either CDR or generation.

Table 2. List of abbreviations.

List of Abbreviations	
Abbreviation	Definition
ASU	Air separation unit to split O_2 from ambient air
BECCS	Bioenergy with carbon capture and storage
BECCUS	Bioenergy with carbon capture, utilisation and storage
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CCU	Carbon capture and utilisation
CCUS	Carbon capture, utilisation and storage
CDR	Carbon-dioxide removal
CPU	Compression unit to compress biogenic CO_2
EI	Emissions intensity (gCO_2/kWh)
ETS	Emissions trading scheme (specifically New Zealand's)
LCNE	Levelised cost of new electricity from retrofit ($/MWh)
LCOE	Levelised cost of electricity of overall plant ($/MWh)
LCOS	Levelised cost of sequestering CO_2 ($/$tCO_2$)
LCRC	Levelised cost of removed CO_2 net from the atmosphere ($/$tCO_2$)
NCG	Non-condensable gasses such as H_2S and CO_2 in geothermal fluid
NPV	Net present value (discounted monetary values over plant life)
OEC	Ormat Energy Converter, a plant design from Ormat Technologies Inc.
OECD	Organisation for Economic Co-operation and Development
OPEX	Operational expenditures from running the power plant
TVZ	Taupō volcanic zone, holding most of New Zealand's geothermal fields

fuel and monitoring), $R_{\mathrm{BioCO_2}}$ is the NPV of revenues from biogenic CO_2 removal and G_{new} is the NPV of increased electricity from the retrofitted plant. LCNE allows the decision maker to compare geothermal-bioenergy-CDR hybrids to any other retrofit project that may result in a higher plant capacity, such as the development of new wells or improvements to the plant's cooling system. Generally, LCNE should be competitive with the price of electricity in the market. For this study, we assume that biogenic CDR will eventually be monetizable using the New Zealand emissions trading scheme (ETS; as of 2024), the Paris Agreement Article 6.4 trading mechanism (UNFCCC 2015), or similar future legislation.

The counterpart to LCNE is the levelised cost of removed CO_2 (*LCRC*), given in $/$tCO_2$, which is useful to compare the cost competitiveness of carbon negative technologies:

$$LCRC = \frac{C_{\mathrm{new}} - R_{G_{\mathrm{new}}}}{E_{\mathrm{BioCO_2}}} \tag{2}$$

where $R_{G_{\mathrm{new}}}$ is the NPV of revenues from the increased electricity generated by the retrofit plant and $E_{\mathrm{BioCO_2}}$ is the NPV of biogenic CDR discounted over the retrofit plant life. Due to the limits of CO_2 solubility in brine, some portion of biogenic CO_2 may need to be vented to the atmosphere or sold for utilisation. A project with an LCRC greater than $200/$tCO_2$ may be considered uncompetitive against other carbon removal technologies (Friedmann et al. 2020). Conversely, a project that achieves ≤$100/$tCO_2$ is considered highly feasible.

Provided there is sufficient market demand, a third term can be introduced into the numerators of Eqns. 1&2 (subtracted from G_{new} and $E_{\mathrm{BioCO_2}}$, respectively): R_{BioCCU}, which is the NPV of revenues of biogenic CO_2 captured and utilised. This ensures that valuable biogenic CO_2 is not wasted and instead becomes a carbon-neutral alternative for industrial applications like horticulture, synthetic aviation fuel and food production.

We assume a discount factor of 8%, in line with expected rates from OECD economies (Park et al. 2021). For simplicity, all NCGs are treated as CO_2.

Ngāwhā station theoretical retrofit

We determine that the simplest retrofit for Station-1 would be to place a biomass boiler in between the production well and the horizontal separator. Doing so would increase the enthalpy of the two-phase fluid entering the separator and result in a larger steam fraction dispatched to the vaporiser. This in turn allows the OEC units to run at a higher cycle pressure.

Additionally, we deem that biogenic CO_2 removal must run concurrently with the plant's existing NCG reinjection from an operational perspective, though this limits the maximum CDR potential. Key calibration data for Station-1 is presented in Table 3. This data was provided by Ngāwhā Generation LTD and matches the operation period of OEC1&2 during January, 2024.

We analyse three theoretical retrofit configurations (Figure 3) in this study: (1) a geothermal-bioenergy hybrid where all biogenic CO_2 is vented, (2) a geothermal-bioenergy hybrid with biogenic CO_2 capture and storage (geothermal-BECCS) where only excess biogenic CO_2 is vented, and (3) a geothermal-bioenergy hybrid where all biogenic CO_2 is either captured or sold for utilisation (geothermal-BECCUS).

Due to constraints on the existing generator at Station-1, all configurations were optimised for an increase of 1 MWe in net power production. Furthermore, we cap the total injection of CO_2 (NCG and biogenic) such that it would completely dissolve at 20 bar and 95°C. This is 2 bar below the running injection pressure (Table 3), ensuring that any natural variation in the injectate temperature (such as from heat exchanger fouling) would not result in CO_2 coming out of solution. Therefore, when factoring the 0.5% (by mass) of NCGs in the production fluid at Station-1, the remaining dissolution capacity is capped at 1.8 tCO_2/h.

For configuration 1, the biomass feedstock is combusted in air, and the flue gas does not need to be compressed. For configurations 2 and 3 we have chosen an oxy-combustion process (Khallaghi et al. 2021), where the biomass feedstock is combusted in pure oxygen. This results in a very high grade of CO_2 in the flue gas stream (>95% composition). An air separation unit (ASU) and accompanying parasitic load are needed to separate O_2 from ambient air. CO_2 dispatched for removal must be compressed to 20 bar in a compression unit (CPU), incurring an additional parasitic load.

The specific design of the oxy-combustion boiler and heat exchanger is beyond the scope of this study. However, we model (1) the heat transfer needed for the optimal

Table 3. Calibration data for Station-1 (OEC1&2) at Ngāwhā geothermal field.

Total production mass rate (t/h)	400
Reservoir temperature (°C)	230
Separator (SP-12) pressure (bar)	14.5
Steam fraction (%)	8
NCG mass fraction (%)	0.5
Injection pump pressure (bar)	22
Reinjection temperature (°C)	95
OEC thermal-electrical efficiency (%)	13

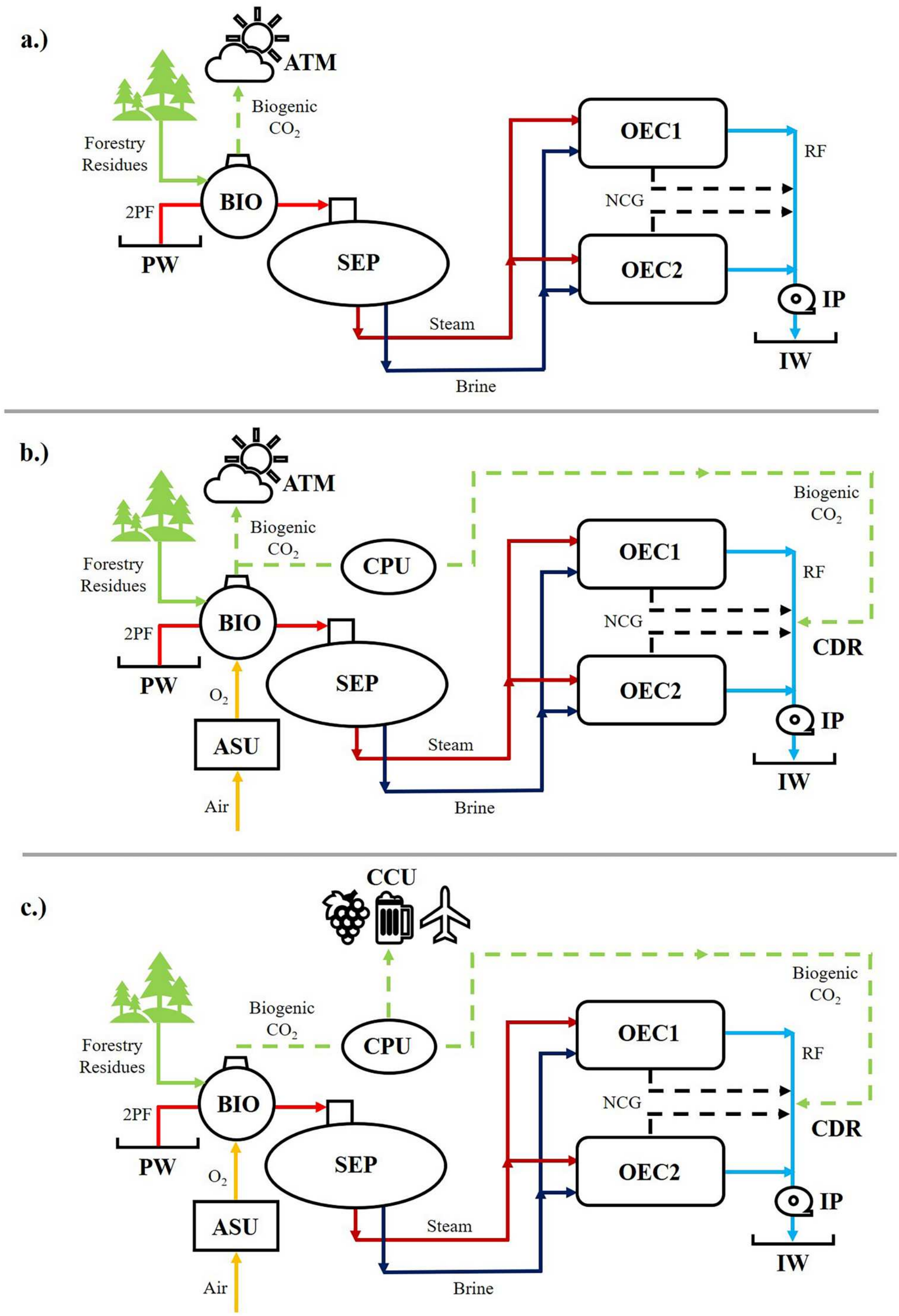

Figure 3. Process schematics for **A**, geothermal-bioenergy hybrid, **B**, geothermal-BECCS and **C**, geothermal-BECCUS at Station-1. PW = production well, SEP = vertical separator, OEC = Ormat Energy Converter unit, IP = injection pump, IW = injection well, BIO = biomass boiler, CPU = compression unit, ASU = Air Separation Unit, CDR = CO_2 removal, CCU = CO_2 utilisation. Red line = two-phase geothermal fluid (2PF), dark red line = steam, dark blue line = brine, blue line = reinjection fluid (RF), dotted black line = non-condensable gasses (NCG), green line = forestry residues, orange line = Air/O_2, dotted green line = biogenic CO_2.

Table 4. Key design parameter ranges for uncertainty quantification.

	Minimum	Maximum	Source
Bioenergy CAPEX rate ($/kWe)	701	7445	IRENA (2021)
Biogenic CO_2 emissivity ($kgCO_2$/kg-wood)	0.78	3.25	Puettmann et al. (2020)
Biomass heating value (MJ/kg)	15	20	Telmo and Lousada (2011)
Onsite monitoring, transport and injection ($/$tCO_2$)	0.9	3.5	Gunnarsson et al. (2018)
Biomass feedstock cost ($/tonne)	24.5	78.6	MPI (2020)

steam fraction, (2) the biomass burn rate needed to achieve this, (3) the amount of oxygen required and (4) the ASU and CPU parasitic loads. In practice, such as for a pilot demonstration, some considerations for biomass storage would also be required. This will ultimately depend on the feedstock supply logistics and operational management of the retrofitted plant. We assumed a retrofit plant life representative of hybrid geothermal power systems of 15 years (Hu et al. 2022), including 2 years of construction, and a capacity factor of 90%.

New Zealand currently has no geological CDR operations and its bioeconomy, with respect to renewable energy, is still emerging (MfE 2022; Coriolis 2023). With no geothermal-bioenergy-CDR plant operating as of 2024, we derive key parameters from the literature (Table 4).

To obtain approximate error bounds, we conducted Monte-Carlo sampling, drawing 1000 uncorrelated parameter values for each model configuration. Values were sampled from uniform distributions with bounding values drawn from literature studies (Table 4). We report the 33rd, 50th and 66th percentile of model outputs to quantify uncertainty (Table 5).

As shown with Eqns. 1&2, the LCNE and LCRC values of geothermal-biomass-CDR retrofits are sensitive to the market price of CO_2 and electricity, respectively. Thus, we vary these two values to examine this sensitivity, thereby delineating the conditions under which each configuration could reach economic feasibility.

For the market price of CO_2, the price points of interest are \$0/tCO_2, \$50/tCO_2 and \$100/tCO_2. The first represents a case where there is no monetary value for CDR activities, but they are undertaken nevertheless. The second is representative of the cost containment trigger price in the 2022 decision (~NZD 80/tCO_2) of the NZ ETS (Reddy

Table 5. Techno-economic model results for all configurations to achieve 1 MWe net increase at Station-1 (CO_2 price = \$50/tCO_2, electricity price = \$60/MWh). Sampling 1000 iterations.

	Geothermal-Bioenergy	Geothermal-BECCS	Geothermal-BECCUS
Optimized steam fraction (%)	10	12	13
Levelised cost of new electricity ($/MWh)	$194\pm^{31}_{28}$	$267\pm^{58}_{51}$	$137\pm^{77}_{92}$
Levelised cost of removed carbon ($/$tCO_2$)	–	$164\pm^{32}_{28}$	$93\pm^{42}_{51}$
Retrofit CAPEX (Mill. $)	$5.4\pm^{1.3}_{1.3}$	$9.9\pm^{2.4}_{2.4}$	$11.8\pm^{2.9}_{2.9}$
Gross power increase (MWe)	1	1.8	2.2
ASU and CPU loads (MWe)	0	0.8	1.2
Biomass burn rate (kt/year)	$12.1\pm^{0.6}_{0.6}$	$22.2\pm^{1.1}_{1.1}$	$26.5\pm^{1.3}_{1.3}$
Biogenic CDR (kt/year)	0	15.9	15.9
Vented biogenic CO_2 (kt/year)	$23.9\pm^{5.2}_{5.2}$	$27.7\pm^{9.5}_{9.6}$	0
Saleable carbon-neutral CO_2 (kt/year)	0	0	$36.1\pm^{11.4}_{11.4}$
Electricity revenue (Mill. $/year)	0.47	0.47	0.47
CDR revenue (Mill. $/year)	0	0.79	0.79
CCU revenue (Mill. $/year)	0	0	$1.8\pm^{0.6}_{0.6}$
Total gas mass fraction of injectate (%)	0.5	0.95	0.95

2023). This is the maximum ETS price before reserve units are triggered for sale, thereby increasing the market's supply of units. The final price point of \$100/tCO_2 is approximately representative of the ETS trigger price as laid out in the 2023 decision (NZD 173/tCO_2, to take effect in 2024). For this study, we assumed that the market price of CO_2 for CCU applications was equivalent to the ETS price, although this can be significantly higher depending on the application and market conditions, as discussed in Section 4.

For electricity prices, we assume that the new electricity generated from the retrofit plant could garner a median and maximum presale price of \$60/MWh and \$120/MWh, respectively. A minimum value of \$0/MWh was also considered for periods of outages where electricity cannot be sold but CO_2 removal or utilisation can continue unperturbed.

Results

We report median values of model outputs for configurations 1–3 in Table 5. Outputs unconstrained by physical limitations (such as generator and dissolution capacity) are reported with 33rd and 66th percentile results. We optimised all retrofit configurations for a net generation increase of 1 MWe at Station-1.

At a CO_2 price of \$50/tCO_2 and an electricity price of \$60/MWh, the geothermal-bioenergy hybrid (without CDR or CCU) operated at the lowest steam fraction (10%), and had the lowest biomass burn rate ($12.1 \pm^{0.6}_{0.6}$ kt/year) and retrofit CAPEX (\$$5.4 \pm^{1.3}_{1.3}$ million). The mass fraction of CO_2 injected into the Ngāwhā reservoir remains unchanged as all biogenic CO_2 is vented to the atmosphere.

In terms of LCNE, the geothermal-BECCUS configuration (\$137/MWh $\pm^{77}_{92}$) outperformed both the geothermal-BECCS (\$267/MWh$\pm^{58}_{51}$) and geothermal-bioenergy (\$194/MWh$\pm^{31}_{28}$) configurations due to the CCU component. At \$50/tCO_2, the annual revenues from 15.9 kt/year of biogenic CDR total \$0.79 million whereas the annual CCU revenues are \$1.8 million.

Component analysis for LCNE and LCRC is given in Figure 4. CAPEX makes up almost half of the LCNE cost for configuration 1 (~\$90/MWh), with fuel costs as the second most critical factor (~\$74/MWh). The geothermal-BECCS configuration followed a similar trend. The greater steam fraction (12%) over configuration 1 necessitates a larger boiler and more biomass feedstock.

For configurations 2 and 3, the CDR revenue component is capped at \$90/MWh due to solubility limits and co-injection of NCGs. This revenue does not offset either the CAPEX component (\$163/MWh and \$196/MWh) or the fuel cost component (\$135/MWh and \$161/MWh) of LCNE.

For geothermal-BECCUS, all biogenic CO_2 must be compressed. Thus, configuration-3 has the greatest steam mass fraction (13%) and ASU and CPU load (1.2 MWe) to achieve a 1 MWe net increase at Station-1. However, the CCU revenue component (~\$206/MWh) is larger than the CAPEX component (~\$196/MWh), the main contributor to configuration 3's relatively low LCNE value.

CCU revenues also factor into the LCRC of geothermal-BECCUS (\$93/t$CO_2 \pm^{42}_{51}$), furthering its advantage as a CDR technology over geothermal-BECCS (\$164/t$CO_2 \pm^{32}_{28}$). Although the geothermal-BECCS retrofit sits

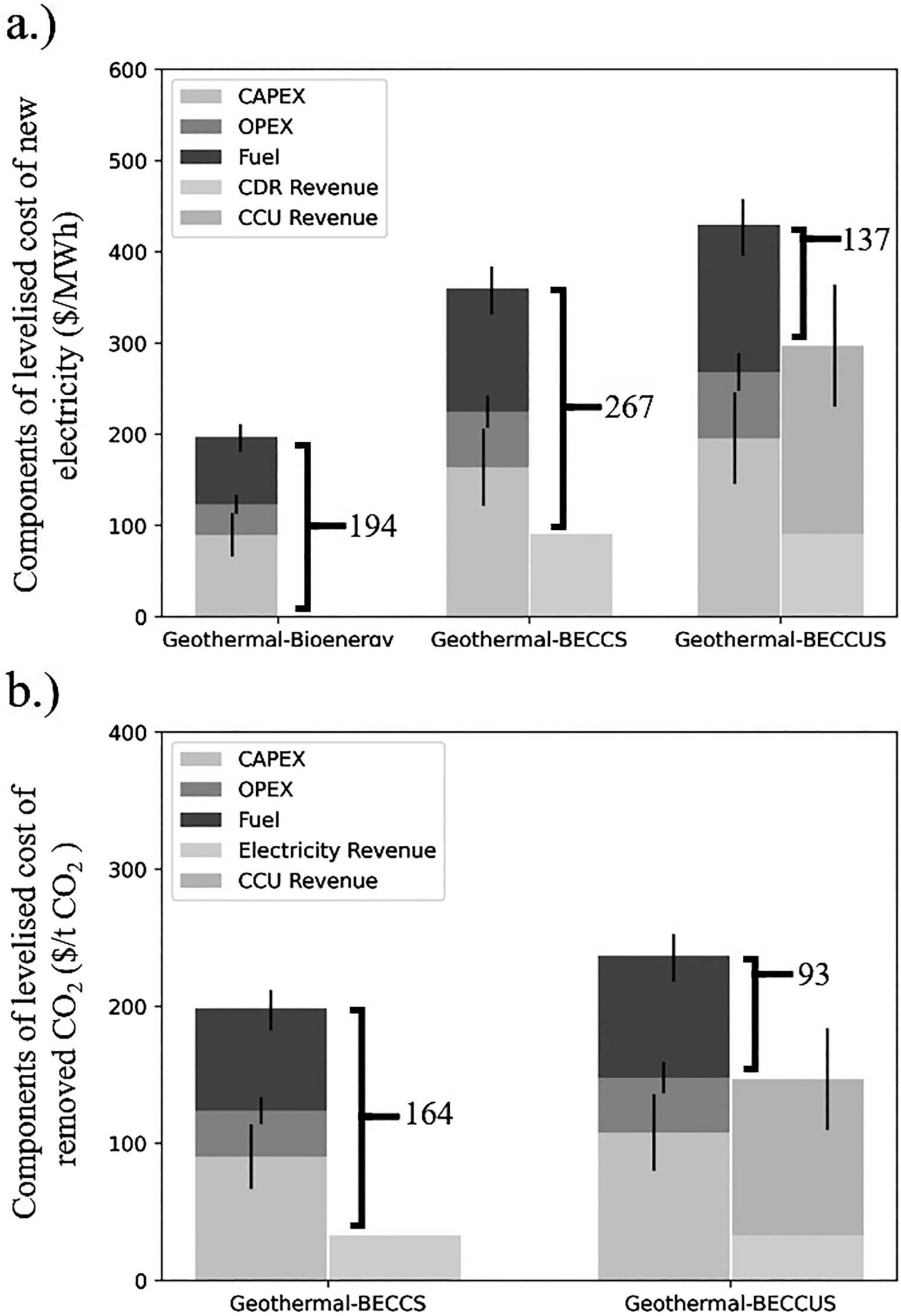

Figure 4. A, Electricity cost, CDR and CCU revenue component analysis of LCNE for the three retrofit designs, **B**, CDR cost, electricity and CCU revenue component analysis for LCRC for geothermal-BECCS and geothermal-BECCUS. Black lines denote the uncertainty range between 33rd and 66th percentile. Costs components are given in the left-hand column and revenue components are given in the right-hand column. Sampling 1000 iterations.

comfortably below the \$200/tCO_2 uncompetitive threshold (Friedmann et al. 2020), geothermal-BECCUS resides in the coveted zone below \$100/tCO_2 for carbon removal technologies. The annual electricity revenues from the 1 MWe

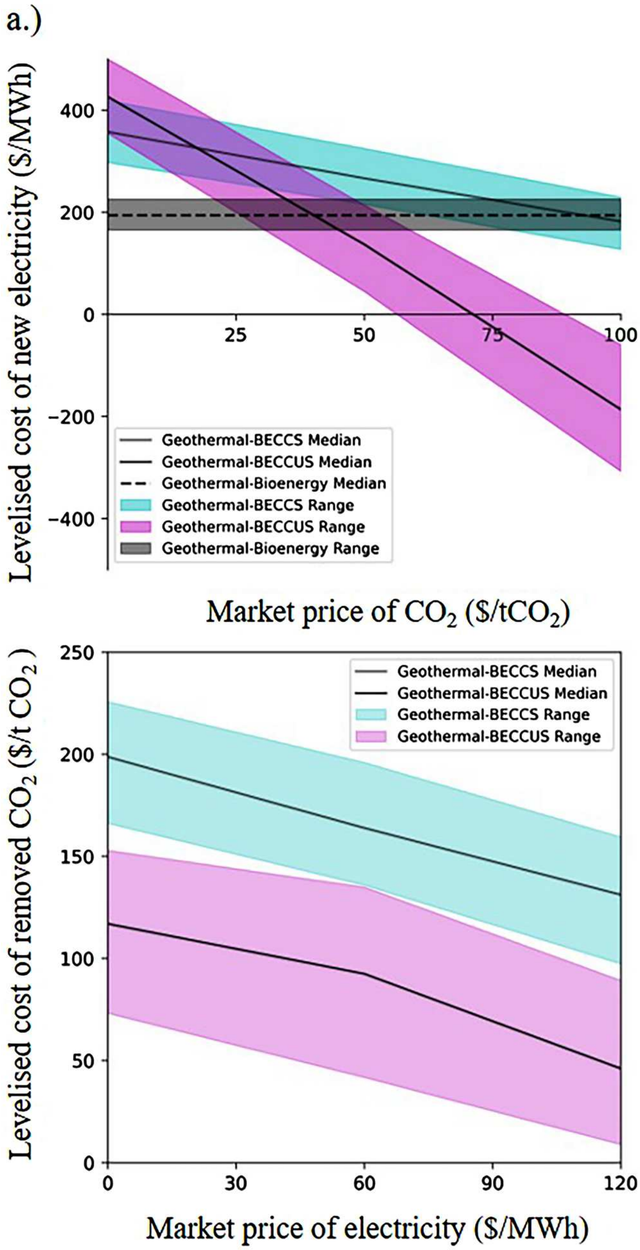

Figure 5. Uncertainty quantification for **A**, LCNE for changing CO_2 market prices for all three retrofit configurations. Sampling 1000 iterations for each of \$0, 50 and 100/tCO_2; and **B**, Uncertainty quantification for LCRC for changing electricity market prices for geothermal-BECCS and geothermal-BECCUS. Sampling 1000 iterations for each of \$0, 60 and 120/MWh.

increase only result in \$0.47 million/year assuming a cost of \$60/MWh across all three configurations, lower than the revenues from CDR (configurations 2 and 3) and CCU (configuration 3).

CAPEX is also the dominant component for LCRC at ~\$90/tCO_2 and ~\$108/tCO_2 for configurations 2 and 3, respectively. Since both retrofits generate 1 MWe, the electricity revenue component is capped at \$33/tCO_2, offsetting roughly one-third of the CAPEX component. The CCU revenue component (~\$114/tCO_2) for geothermal-BECCUS fully offsets CAPEX.

The effects of the market price of CO_2 and electricity on the financial viability of the three configurations are depicted in Figure 5. Configuration 1 is unaffected by any change to the market price of CO_2 (Figure 5A), meaning that if all else stays constant it will result in a relatively expensive retrofit to increase renewable electricity generation. The LCNE of geothermal-BECCS is on par with configuration 1 at ~\$90/tCO_2. However, there is potential for overlap between the two configurations from ~\$45 to 100/tCO_2.

Geothermal-BECCUS has a lower LCNE than geothermal-BECCS at CO_2 prices >\$20/tCO_2 and the standalone geothermal-bioenergy retrofit at >\$40/tCO_2. Importantly, geothermal-BECCUS reaches negative LCNE values at CO_2 prices >\$70/tCO_2, meaning that the revenue from biogenic CDR and CCU outweighs any cost to produce the 1 MWe net of electricity.

In terms of LCRC (Figure 5B), median results for geothermal-BECCS never reach ≥\$200/tCO_2, even at electricity prices of \$0/MWh. Nevertheless, it is unlikely that geothermal-BECCS can cross the ≤\$100/tCO_2 threshold up to a presale electricity price of \$120/MWh. Thus, at no point do geothermal-BECCS and geothermal-BECCUS intersect, meaning that at any given electricity price geothermal-BECCUS is the more cost-effective CO_2 removal retrofit configuration.

From a carbon accounting perspective, the emissions intensity of configuration 1 would remain at 0 gCO_2/kWh. However, for geothermal-BECCS and geothermal-BECCUS, the permanent removal of 15.9 kt/year of biogenic CO_2 would result in an emissions intensity (EI) of −2017 gCO_2/kWh for the new electricity, roughly able to offset twice the CO_2 as emitted by a 1 MWe coal power plant (EIA 2021). The overall EI of Station-1 (~9 MWe after retrofit) would reach −224 gCO_2/kWh.

Discussion

We showed that combined geothermal-bioenergy-CDR operations could be a compelling retrofit option for Station-1 at Ngāwhā geothermal field provided that CDR is monetizable and excess biogenic CO_2 is sold for utilisation. The viability and value of CDR projects will depend on the context. For example, in countries with high fossil-fuel penetration in the electricity sector it may be more straightforward to directly phase out these power plants with low cost wind and solar energy (IPCC 2023). However, almost half of New Zealand's greenhouse gas emissions come from agriculture (McDowell et al. 2024), which cannot be offset by further renewable electrification. BECCS and other CDR related technologies thus offer critical strategic flexibility in avoiding overshoot our emissions budget (IPCC 2023).

The prospect of geological storage of removed biogenic CO_2 could supplement New Zealand's ambitious climate targets (The Parliament of New Zealand 2019) and, along with economy-wide decarbonisation, help to avoid any overshoot of emissions budgets. New Zealand's current and only approach to CDR, afforestation, is cost-effective but requires new land to be repurposed (Humpenöder et al. 2014).

Furthermore, afforestation presents durability concerns with regard to long-term CO_2 reduction (Keenan 2015). Increased droughts, fires and cyclones will increase tree mortality rates (Williams et al. 2019; Wu et al. 2021; Iglesias et al. 2022; Juang et al. 2022), thereby returning CO_2 stocks to the atmosphere, cutting short the timeline of impacted forestry credits (Anderegg et al. 2020; Wu et al. 2023). Thus, multiple CDR approaches in tandem may help balance out CO_2 budgets and avoid the risk of CO_2 escape.

Geothermal fields that have degassed and emitted NCG substantially since their inception, such as Ngāwhā, may have sufficient space to store large amounts of biogenic CO_2 for long periods. Pressure maintenance of geothermal systems is integral to the long-term CO_2 storage opportunities (Kervévan et al. 2017). Therefore, monitoring the migration of dissolved CO_2 towards surface manifestations and the production zone would need to be considered as part of reservoir management. The concentration of total CO_2 for the geothermal-BECCS and geothermal-BECCUS retrofits remained lower than the original NCG concentration from Station-1 in 1998. Nevertheless, the mineralisation rate of dissolved CO_2 remains an open question at Ngāwhā geothermal field.

Any bioenergy-based retrofit of Station-1 would require consistent access to a supply of feedstock. Ideally, this feedstock should be sourced from the Far North to minimise trucking costs and transport emissions. Chip and hog quality residues are estimated to each have a long-term supply of 0.18 million m^3 in Northland (MPI 2020). Factoring in a forestry residue density of 1234 kg/m^3 (Nurek et al. 2019), we estimate a potential ~445 kt/year of feedstock supply. For context, the 66th percentile biomass burn rate for geothermal-BECCUS required ~28 kt/year, roughly 6% of this estimated total supply. An uptake in bioenergy projects in New Zealand may also reduce woody debris and forestry slash left on the forest floor, which can become mobilised during extreme weather events (Payn 2023).

The practical implementation of bioenergy hybrids at geothermal power plants may require further consideration or else risk higher retrofit CAPEX. For example, the existing separator on site must be able to handle the increase in steam fraction of a retrofit. Additionally, there may be capacity restrictions on the generator that limit the maximum work the binary turbine can produce. Finally, as with all retrofit projects, the retrofitted plant must perform adequately for a suitable duration of time to justify the financial investment and avoid stranding of assets.

Carbon-neutral biogenic CO_2 is a valuable product for sustainable aviation fuel, greenhouses, and food production. The high-purity CO_2 flue stream from oxy-combustion (~95%) may present a better opportunity for food-grade CO_2 than geothermal NCGs since the latter are not carbon neutral. Recently, New Zealand has faced shortages of food grade CO_2 (Olley 2023). The Kapuni petrochemical plant's temporary closure in 2022 saw the price of food-grade CO_2 rise to ~\$2200/tCO_2 (Olley 2023). Assuming there was the demand for all 36 ktCO_2/year produced from the geothermal-BECCUS retrofit, this would result in annual CCU revenues of \$80 million. This would dwarf the \$0.79 and \$0.47 million in annual revenues from CDR and electricity production, respectively, and could justify investigating improving the biogenic CO_2 purity from 95% to 99.9% (Esposito et al. 2019).

In general, geothermal-biomass-CDR hybrids could offer multi-faceted decarbonisation potential. For example, New Zealand ranked 6th in the world for per capita aviation emissions in 2019 (Callister and McLachlan 2023), which represent roughly 12% of the country's gross emissions. These emissions cannot easily be mitigated with renewable electricity, but they can be indirectly offset via CDR (Friedmann et al. 2020) or eliminated by using biogenic CO_2 as an alternative feedstock for sustainable aviation fuel.

Conclusion

A potential bioenergy retrofit of Ngāwhā geothermal power station could result in increased electricity output, negative CO_2 emissions and valuable carbon neutral CO_2. We showed that a retrofit geothermal-bioenergy-CDR hybrid plant optimised for an increase in 1 MWe could achieve carbon removals of 15.9 $ktCO_2$/year.

We also show that additional CCU activities can make the project more lucrative if biogenic CO_2 is produced at a greater rate than can be dissolved in the geothermal brine. In such a scenario, the levelised costs of new electricity and carbon removal could drop to \$137/MWh and \$93/tCO_2, respectively.

The latter value lies below the desirable threshold of \$100/tCO_2 for carbon removal projects and could thus be considered a cost-effective way at offsetting CO_2 emissions from other sectors in New Zealand's economy. It is possible that at high CO_2 market prices still within the bounds of the ETS trigger price, the increased electricity generation could come at no cost. Finding ways to lower boiler CAPEX and acquire feedstock cheaply could be integral in lowering costs further.

The biomass burn rate required for the retrofit ($26.5 \pm^{1.3}_{1.3}$ kt/year) is only 6% of the total Far North supply of chip and hog quality forestry residues. If the plant was implemented today, biogenic CCU would yield the most lucrative of the three revenue streams at \$2 million/year, followed by CDR at \$0.79 million/year and electricity generation at \$0.47 million/year.

We argue New Zealand has the natural resources and regulatory framework to become a world leader in CO_2 removal. Geothermal energy has played an important role in both the country's domestic development and foreign relations (Steff 2019; Chelminski 2022). New Zealand also has a robust forestry industry and a growing need to address forestry slash. Combining these three concepts could offer multiple value chains, durable pathways to achieve climate targets, and build international relationships via the exchange of expertise and aid. Therefore, the next steps are to demonstrate these concepts in practice with a pilot demonstration of geothermal-bioenergy-CDR hybrids.

Acknowledgements

We extend our thanks to Top Energy and Ngāwhā Generation Ltd for allowing us to use the Ngāwhā power station for this theoretical case study. We also thank Prof. Rosalind Archer for her continued support and engagement with our research.

Disclosure statement

No potential conflict of interest was reported by the author(s).

ORCID

Karan Titus http://orcid.org/0000-0002-3885-1682
Rebecca Peer http://orcid.org/0000-0002-9951-2625

References

Anderegg WR, Trugman AT, Badgley G, Anderson CM, Bartuska A, Ciais P, Cullenward D, Field CB, Freeman J, Goetz SJ, et al. 2020. Climate-driven risks to the climate mitigation potential of forests. Science. 368(6497):eaaz7005. doi:10.1126/science.aaz7005.

Callister P, McLachlan RI. 2023. Managing Aotearoa New Zealand's greenhouse gas emissions from aviation. Journal of the Royal Society of New Zealand. 54(4):1–21.

Chelminski K. 2022. Climate finance effectiveness: a comparative analysis of geothermal development in Indonesia and the Philippines. The Journal of Environment & Development. 31 (2):139–167. doi:10.1177/10704965211070034.

Coriolis. 2023. Finding the way: emerging and future platforms in New Zealand's bioeconomy.

Dal Porto F, Pasqui G, Fedeli M. 2016. Geothermal power plant production boosting by biomass combustion: Cornia 2 case study. Proceedings of the European Geothermal Congress.

Dipippo R. 2016. Geothermal power plants: principles, applications, case studies and environmental impact. 4th ed. Elsevier Science.

EIA. 2021. Annual Energy Outlook 2021. https://www.eia.gov/outlooks/aeo/.

Esposito E, Dellamuzia L, Moretti U, Fuoco A, Giorno L, Jansen JC. 2019. Simultaneous production of biomethane and food grade CO_2 from biogas: an industrial case study. Energy & Environmental Science. 12(1):281–289. doi:10.1039/C8EE02897D.

Friedmann J, Fan Z, Byrum Z, Ochu E, Bhardwaj A, Sheerazi H. 2020. Levelized cost of carbon abatement: an improved cost-assessment methodology for a net-zero emissions world. New York, NY, USA: Columbia University SIPA Center on Global Energy Policy.

Gunnarsson I, Aradóttir ES, Oelkers EH, Clark DE, Arnarson MÞ, Sigfússon B, Snæbjörnsdóttir SÓ, Matter JM, Stute M, Júlíusson BM. 2018. The rapid and cost-effective capture and subsurface mineral storage of carbon and sulfur at the CarbFix2 site. International Journal of Greenhouse Gas Control. 79:117–126. doi:10.1016/j.ijggc.2018.08.014.

Hu S, Yang Z, Li J, Duan Y. 2022. Optimal solar thermal retrofit for geothermal power systems considering the lifetime brine degradation. Renewable Energy. 186:628–645. doi:10.1016/j.renene.2022.01.028.

Humpenöder F, Popp A, Dietrich JP, Klein D, Lotze-Campen H, Bonsch M, Bodirsky BL, Weindl I, Stevanovic M, Müller C. 2014. Investigating afforestation and bioenergy CCS as climate change mitigation strategies. Environmental Research Letters. 9(6):064029. doi:10.1088/1748-9326/9/6/064029.

Iglesias V, Balch JK, Travis WR. 2022. US fires became larger, more frequent, and more widespread in the 2000s. Science Advances. 8(11):eabc0020. doi:10.1126/sciadv.abc0020.

Intergovernmental Panel on Climate Change (IPCC). 2023. Synthesis report of the IPCC Sixth Assessment Report (AR6): summary for policymakers.

IRENA. 2021. Renewable power generation costs in 2021, International Renewable Energy Agency, Abu Dhabi.

Janes J. 1984. Evaluation of a superheater enhanced geothermal steam power plant in the Geysers area. Final report (No. P-700-84-003). California Energy Resources Conservation and Development Commission, Sacramento (USA). Siting and Environmental Div.

Juang CS, Williams AP, Abatzoglou JT, Balch JK, Hurteau MD, Moritz MA. 2022. Rapid growth of large forest fires drives the exponential response of annual forest-fire area to aridity in the western United States. Geophysical Research Letters. 49(5):e2021GL097131. doi:10.1029/2021GL097131.

Keenan RJ. 2015. Climate change impacts and adaptation in forest management: a review. Annals of Forest Science. 72:145–167. doi:10.1007/s13595-014-0446-5.

Kervévan C, Beddelem M-H, Galiègue X, Le Gallo Y, May F, O'Neil K, Sterpenich J. 2017. Main results of the CO2-DISSOLVED project: first step toward a future industrial pilot combining

geological storage of dissolved CO_2 and geothermal heat recovery. Energy Procedia. 114:4086–4098. doi:10.1016/j.egypro.2017.03.1549.
Khallaghi N, Jeswani H, Hanak DP, Manovic V. 2021. Techno-economic-environmental assessment of biomass oxy-gasification staged oxy-combustion for negative emission combined heat and power. Applied Thermal Engineering. 196:117254. doi:10.1016/j.applthermaleng.2021.117254.
Lehtveer M, Emanuelsson A. 2021. BECCS and DACCS as negative emission providers in an intermittent electricity system: why levelized cost of carbon may be a misleading measure for policy decisions. Frontiers in Climate. 3:647276. doi:10.3389/fclim.2021.647276.
MBIE. 2021. Energy in New Zealand 2021. https://www.mbie.govt.nz/building-and-energy/energy-and-natural-resources/energy-statistics-and-modelling/energy-publications-and-technical-papers/energy-in-new-zealand/.
McDowell RW, Herzig A, van der Weerden TJ, Cleghorn C, Kaye-Blake W. 2024. Growing for good: producing a healthy, low greenhouse gas and water quality footprint diet in Aotearoa, New Zealand. Journal of the Royal Society of New Zealand. 54(3):325–349. doi:10.1080/03036758.2022.2137532.
McLean K, Richardson I, Quinao J, Clark T, Owens L. 2020. Greenhouse gas emissions from New Zealand geothermal: power generation and industrial direct use. In Proceedings 42nd New Zealand Geothermal Workshop. 24:26.
MfE. 2022. Towards a productive, sustainable and inclusive economy: Aotearoa New Zealand's first emissions reduction plan.
Minx JC, Lamb WF, Callaghan MW, Fuss S, Hilaire J, Creutzig F, Amann T, Beringer T, de Oliveira Garcia W, Khanna T, et al. 2018. Negative emissions—part 1: research landscape and synthesis. Environmental Research Letters. 13(6):063001. doi:10.1088/1748-9326/aabf9b.
MPI. 2020. Wood fibre futures stage: one report. Wellington: Ministry of Primary Industries.
Nurek T, Gendek A, Roman K. 2019. Forest residues as a renewable source of energy: elemental composition and physical properties. BioResources. 14(1):6–20. doi:10.15376/biores.14.1.6-20.
Olley S. 2023. Beer, bread, burgers - impact of CO_2 shortage revealed. 1News. https://www.1news.co.nz/2023/05/30/beer-bread-burgers-impact-of-co2-shortage-revealed/.
Park S, Langat A, Lee K, Yoon Y. 2021. Measuring the impact of risk on LCOE (levelized cost of energy) in geothermal technology. Geothermal Energy. 9(1):27. doi:10.1186/s40517-021-00209-9.
Payn T. 2023. Keeping woody debris inside our forests–what we need to do. NZ Journal of Forestry. 68(1):3.
Puettmann M, Sahoo K, Wilson K, Oneil E. 2020. Life cycle assessment of biochar produced from forest residues using portable systems. Journal of Cleaner Production. 250:119564. doi:10.1016/j.jclepro.2019.119564.
Ratouis TM, Snæbjörnsdóttir SÓ, Voigt MJ, Sigfússon B, Gunnarsson G, Aradóttir ES, Hjörleifsdóttir V. 2022. Carbfix 2: a transport model of long-term CO2 and H2S injection into basaltic rocks at Hellisheidi, SW-Iceland. International Journal of Greenhouse Gas Control. 114:103586. doi:10.1016/j.ijggc.2022.103586.
Reddy P. 2023. Climate Change (Auctions, Limits and Price Controls for Units) Regulations 2020. Version as at 1 November 2023.
Rekker S, Chen G, Heede R, Ives MC, Wade B, Greig C. 2023. Evaluating fossil fuel companies' alignment with 1.5 C climate pathways. Nature Climate Change. 13(9):927–934. doi:10.1038/s41558-023-01734-0.
Schneider J, Richter A. 2020. Global Geothermal Power Plant map. ThinkGeoEnergy; [accessed 2024 Jan]. https://www.thinkgeoenergy.com/map/last.
Scott M. 2022. A space tourism destination: environmental, geopolitical and tourism branding considerations for New Zealand as a 'launch state'. Journal of Sustainable Tourism. 30(9):2240–2253. doi:10.1080/09669582.2020.1817049.
Steff R. 2019. Looking to the future: expanding New Zealand foreign relations beyond traditional partnerships. In: Brady AM, editor. Small states and the changing global order: New Zealand faces the future. Cham: Springer; p. 231–249.

Telmo C, Lousada J. 2011. Heating values of wood pellets from different species. Biomass and Bioenergy. 35(7):2634–2639. doi:10.1016/j.biombioe.2011.02.043.

Thain I, DiPippo R. 2015. Hybrid geothermal-biomass power plants: applications, designs and performance analysis. Proceedings World Geothermal Congress, Melbourne, Australia.

The Parliament of New Zealand. 2019. Climate Change Response (Zero Carbon) Amendment Act. http://www.legislation.govt.nz/act/public/2019/0061/latest/LMS183736.html.

Titus K, Dempsey D, Peer R, Archer R. 2023b. Carbon negative geothermal: techno-economic analysis of geothermal energy combined with direct and biomass-based carbon dioxide removal. Available at SSRN 4655245.

Titus KA, Dempsey DE, Peer RAM. 2023a. Carbon negative geothermal: theoretical efficiency and sequestration potential of geothermal-BECCS energy cycles. International Journal of Greenhouse Gas Control. 122:103813. doi:10.1016/j.ijggc.2022.103813.

Toselli D, Heberle F, Brüggemann D. 2019. Techno-economic analysis of hybrid binary cycles with geothermal energy and biogas waste heat recovery. Energies. 12(10):1969. doi:10.3390/en12101969.

United Nations Framework Convention on Climate Change (UNFCC). 2015. Paris Agreement.

Wang Y, Sharp B, Poletti S, Nam KM. 2022. Economic and land use impacts of net zero-emission target in New Zealand. International Journal of Urban Sciences. 26(2):291–308. doi:10.1080/12265934.2020.1869582.

Williams AP, Abatzoglou JT, Gershunov A, Guzman-Morales J, Bishop DA, Balch JK, Lettenmaier DP. 2019. Observed impacts of anthropogenic climate change on wildfire in California. Earth's Future. 7(8):892–910. doi:10.1029/2019EF001210.

Wu C, Coffield SR, Goulden ML, Randerson JT, Trugman AT, Anderegg WR. 2023. Uncertainty in US forest carbon storage potential due to climate risks. Nature Geoscience. 16(5):422–429. doi:10.1038/s41561-023-01166-7.

Wu C, Venevsky S, Sitch S, Mercado LM, Huntingford C, Staver AC. 2021. Historical and future global burned area with changing climate and human demography. One Earth. 4(4):517–530. doi:10.1016/j.oneear.2021.03.002.

Zhang X, Zeng R, Deng Q, Gu X, Liu H, He Y, Zeng R, Deng Q, Gu X, Liu H, et al. 2019. Energy, exergy and economic analysis of biomass and geothermal energy based CCHP system integrated with compressed air energy storage (CAES). Energy Conversion and Management. 199:111953. doi:10.1016/j.enconman.2019.111953.

Zyvoloski G. 2007. FEHM: A control volume finite element code for simulating subsurface multi-phase multi-fluid heat and mass transfer. Los Alamos unclassified report LA-UR-07-3359.