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Carbon Negative Geothermal: Theoretical Efficiency and Sequestration Potential of Geothermal-BECCS Energy Cycles

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1. Abstract

Geothermal systems are an attractive option for baseload electricity generation with low emissions intensity (average 122 gCO₂/kWh). However, about 70% of geothermal systems are low or medium enthalpy (<160°C), which often renders them uneconomic to develop for electricity production. A solution to increase both power production and utilization efficiency of these systems is hybridization with a biomass fuel source. In this work, we introduce and verify the concept of biomass hybridization combined with in-line dissolution and reinjection of biomass flue CO₂. This subclass of bioenergy and carbon capture and storage (BECCS), termed geothermal-BECCS, has improved power production and negative CO₂ emissions. This dual approach of using geothermal systems for power production and as carbon sinks can be a potential decarbonisation tool in areas with suitable geothermal and bioenergy resources.

Here, we quantify the thermodynamic and sequestration performance of four geothermal-BECCS configurations. Up to 100% of flue gas is dissolved and reinjected with the spent geofluid. Scaled to a 1 kg/s geofluid production rate, flash and binary benchmark plants generated 32 and 43 kWe at efficiencies of 6 and 8% respectively. In comparison, four geothermal-BECCS designs yielded 64 kWe at 9% efficiency (flash plant), 76 kWe at 9% efficiency (ORC binary plant), 62 kWe at 7% efficiency

(compound flash-binary plant), and 368 kWe at 19% efficiency (bioenergy based geothermal-preheat plant). Annual biogenic CO₂ sequestration rates ranged from 217 to 675 tonnes per kg/s with emissions intensities from -209 to -922 gCO₂/kWh. By simultaneously boosting low-emissions energy and sequestering bio-origin CO₂, geothermal-BECCS promises to be an essential technology for meeting climate targets.

2. Introduction

Geothermal energy is a renewable and relatively clean source of electricity generation with a global installed capacity of about 14 GW in 2020. The countries with the highest installed capacities, such as the United States, Indonesia, Philippines, Turkey and Aotearoa New Zealand, have mature and high temperature geothermal resources (REN21, 2021). However, about 70% of the world's geothermal systems are classified as low or medium enthalpy (Franco & Villani, 2009; Hochstein, 1990) with reservoir temperatures below 160°C.

Basic flash plants are considered infeasible for these systems, as the low electricity yields do not justify the high development risk and capital costs (Dickson & Fanelli, 2003). The most widely deployed technology for these reservoirs is the organic Rankine cycle (ORC) binary plant, which made up 35% of all operating geothermal units in 2015 (DiPippo, 2016). By inducing heat transfer from the geofluid to a secondary working fluid, usually a hydrocarbon, binary plants have been used with very low reservoir temperatures, e.g., 73°C at Chena Hot Springs, Alaska (Zarrouk & Moon, 2014).

Another way to potentially exploit low temperature resources is to pair geothermal energy with a secondary fuel source, such as fossil fuels, solar energy or a biomass feedstock (DiPippo, 2016). The success of such hybrid energy schemes is dependent on the colocation and thermodynamic synergy between geothermal and secondary energy sources (DiPippo, 2016). While fossil fuel hybrids would have high CO₂ emissions and solar hybrids are subject to seasonal and diurnal intermittency, combining geothermal with biomass heating offers a carbon neutral combustion process because the

feedstock absorbs atmospheric carbon during growth. If these emissions are captured, the energy cycle itself is carbon negative.

In this article, we introduce a novel negative emissions energy cycle that combines biomass hybridization and bio-origin flue carbon capture and sequestration, termed geothermal-BECCS. This energy cycle aims to aggressively promote decarbonisation by both boosting renewable power and operating with negative emissions. In the past, conventional BECCS has been described as an important negative emissions technology that has been identified as essential for meeting international climate targets (Fridahl & Lehtveer, 2018; Friedmann et al., 2020). Utilizing geothermal reservoirs and in-line dissolution for BECCS operations is a new proposal that addresses CO₂ buoyancy and caprock security issues while making use of low temperature geothermal resources.

To illustrate the function and efficiencies of geothermal-BECCS systems, we propose four novel geothermal-BECCS plant configurations and quantify their thermodynamic and sequestration performance. This work is a first step toward determining the techno-economic feasibility of such systems.

Magmatic-origin CO₂ emissions (Ármansson et al., 2005) are already captured at Hellisheidi geothermal field in Iceland using in-line dissolution technology installed in reinjection wells (Sigfússon et al., 2018). Deploying biomass heating at low enthalpy systems along with in-line dissolution of bio-origin flue CO₂ could simultaneously improve conversion efficiency while ensuring negative operational emissions. A conceptual diagram of geothermal-BECCS systems is illustrated in Figure 1.

recovery system that could superheat the geothermal steam. The latter method was considered more reliable due to the concurrent electricity generation of the steam and natural gas turbines.

Another hybrid geothermal-fossil fuel configuration involves preheating feed-water in conventional thermal cycles using hot geofluid (DiPippo, 2016; Kestin et al., 1978). In a pure fossil fuel plant, a portion of superheated steam is bled and extracted at several points during the turbine expansion process for feed-water preheating. Thus, the thermodynamic advantage of coupling geothermal energy for this preheating results in an increased mass rate through the turbine, ultimately improving the total power production of the plant. Tasking geothermal energy for feed-water heating can increase the potential power output of a plant by up to 60% (Khalifa et al., 1978; Liu et al., 2016). A case study at the Roosevelt Hot springs in Utah concluded that such a system would be technically and economically feasible (Parsons, 1978; DiPippo, 2016). In fact, feed-water preheating was concluded to be the only feasible solution when trying to exploit low enthalpy geothermal systems for hybrid geothermal-fossil fuel plants (Bruhn, 2002).

Compound flash-binary hybrids were considered by DiPippo et al. (1981), where geothermal steam flashed at a separator was subsequently superheated prior to turbine entry. The separated brine was then used for feed-water heating in an ancillary Rankine cycle. This was deemed most suitable when the geofluid at the wellhead was two-phase, making it suboptimal for feed-water heating alone.

In addition to fossil-geothermal hybrids, solar superheating of geofluid has been demonstrated in El Salvador and Iceland, with low initial geofluid temperatures of 154°C and 125°C, respectively (Li et al., 2020). Solar energy has also been considered for power boosting at an ORC binary plant operating below design capacity (Manente et al., 2011).

However, while solar energy presents a carbon neutral secondary energy source, an element of strategic planning is required due to its diurnal and seasonal nature (Greenhut et al., 2010; Manente et al., 2011). The economic viability of a solar-geothermal hybrid plant is thus dependent on variations in solar intensity, latitude, weather and topographical setting.

Coupling bioenergy with geothermal systems is an alternative carbon neutral cycle with the potential advantage of more stable secondary heating than solar. Thain & DiPippo (2015) evaluated the hypothetical introduction of a biomass superheater to the Rotokawa I geothermal field (rated at 29 MWe) in Aotearoa New Zealand. The biomass boosting increased the power output from the back-pressure turbine by 6.9 MWe. Due to the high enthalpy retained by the turbine exhaust steam, the case study considered using exhaust heat recovery to provide further energy to the binary units, resulting in an additional 1.6 MWe.

Forestry waste from the Kaingaroa Forest was considered for the biomass feedstock for the boiler due to the proximity of the forest to Aotearoa New Zealand's Taupo Volcanic Zone (TVZ), where the plant is located. The use of this fuel was considered carbon neutral because the absorption and release of CO₂ remains within the terrestrial carbon cycle. However, collection and transport emissions would need to be quantified in a complete emissions assessment.

An industry application of a geothermal-bioenergy cycle was tested at the Larderello geothermal field in Italy. A biomass superheater was implemented at the 20 MWe Cornia-2 facility (Dal Porto et al., 2016), which was performing below design capacity. The plant was retrofitted to provide steam superheating to 370°C, adding 6 MWe of power with a turbine inlet pressure of 5 bar. The biomass feedstock was sourced from local suppliers, meeting the important colocation requirement. Municipal financial incentives and a dedicated feed-in tariff improved the viability of the retrofit project. Hybridization resulted in relatively few changes to the existing infrastructure beyond the insertion of the biomass boiler and a heat exchanger.

The successful implementation of geothermal-bioenergy hybrids is thus site-specific and the design is primarily dependent on colocation and reservoir temperature (DiPippo, 2016; DiPippo et al., 1981; Thain & DiPippo, 2015; Janes, 1984). Additionally, hybrid plants are subject to local market conditions and economic incentives (Bruhn, 2002; Dal Porto et al., 2016; Manente et al., 2011).

3.2. Geothermal and CCS

Carbon capture and storage (CCS) is a technically feasible industrial-scale technology that typically involves the post-combustion capture of CO₂. Conventional CCS has largely been applied to fossil fuels in order to attain carbon neutrality or minimize positive emissions (Galiègue & Laude, 2017). Studies have often focused on capturing and sequestering liquified or supercritical CO₂ within geological formations, ideally at large volumes. However, free-phase CO₂ is buoyant relative to groundwater, and therefore could be prone to leakage unless caprock security can be demonstrated (Kaya & Zarrouk, 2017; Kervévan et al., 2013). CCS technologies are also heavily tied to the price of carbon (Galiègue & Laude, 2017). The incremental cost of capture and transportation, mixed with insufficient market incentives, has made conventional CCS difficult to implement on a wide scale into the energy sector (de Coninck et al., 2018; IEA, 2017).

One advantage of using geothermal for CCS schemes is that CO₂ can be sequestered via in-line dissolution using existing infrastructure, removing the need for offsite transportation and reducing costs (Kervévan et al., 2017). The Icelandic geothermal community had originally developed in-line dissolution for sequestering magmatic-origin CO₂ and H₂S emissions from geothermal power plants to comply with emissions standards introduced by the Icelandic government (Berstad & Nord, 2016; Sigfússon et al., 2018).

In-line dissolution consists of releasing the CO₂ from an interior pipe in the wellbore for dissolution beneath the reinjection fluid column. As CO₂ solubility in water increases with elevated pressures (Duan & Sun, 2003), the rate of sequestration is improved for higher dissolution pressure. Basalt formations were specifically targeted for sequestration in the CarbFix project to rapidly induce CO₂ mineralisation. Sequestration through mineral storage is noted to have high capacity and secure trapping (Sigfússon et al., 2018).

Furthermore, the carbonated water is denser than freshwater, mitigating the buoyancy risk associated with free-phase CO₂ in conventional CCS. The lack of buoyant, free-phase CO₂ allows for shallower depths to be utilized for storage, and the efficacy of the cap rock is less integral (Sigfusson et al., 2015).

Reinjection of CO₂-charged geofluid has been shown through modelling to be a suitable sequestration tool, provided there is careful reservoir management to maintain pressure and avoid thermal and chemical breakthrough (Kaya & Zarrouk 2017).

In 2017, 34% of CO₂ emissions (10,000 tonnes) and 68% of H₂S (5,000 tonnes) were captured at the industrial site and successfully sequestered (Gíslason et al., 2018). The cost of CCS through in-line dissolution at Hellisheidi was found to be two to four times less than conventional CCS, in part due to the capital cost-savings of using existing reinjection wells. However, the potential for sequestration through in-line dissolution is ultimately dependent on the solubility of CO₂ in the reinjection fluid. The successful application of CCS for magmatic origin CO₂ had prompted interest in direct air capture and sequestration (DACS) at Hellisheidi (Gutknecht et al., 2018).

The CO₂-DISSOLVED case study in France also considered the use of geothermal reinjection fluid as a medium for CCS for low range CO₂ emitters. In this case study, low enthalpy geothermal energy was integrated with an existing natural gas boiler at a bioethanol plant, sequestering the flue gas CO₂ through aqueous dissolution (Galiègue & Laude, 2017). The CO₂ is thought to be maintained in solution by pressure maintenance of the reservoir, although emissions capture was limited to 33% due to the solubility of CO₂ in the reinjection fluid (Galiègue & Laude, 2017).

3.3. Bioenergy & Carbon Capture and Storage (BECCS)

BECCS is an emerging technology where emissions from bioenergy combustion are captured and sequestered. The global sequestration potential of BECCS is estimated to be 3.3 - 7.5 Gt-CO₂ per year (Kemper, 2015; Woolf et al., 2010), which is between 10 to 23% of worldwide CO₂ emissions (IEA, 2021). BECCS has been promoted as an important component of emissions reduction pathways to keep global temperature rise below 1.5°C, with its viability as a negative emissions tool predicated on the assumption that emissions from the bioenergy is carbon neutral (de Connick et al., 2018; Fridahl & Lehtveer, 2018; Kemper, 2015; Kervévan et al., 2017).

The 5th assessment report (AR5) by the International Panel of Climate Change (IPCC) indicates most emissions scenarios cannot achieve a decline in atmospheric CO₂ concentrations below 450ppm before 2100 without deployment of BECCS technology (Fridahl & Lehtveer, 2018). Furthermore, the Shared Socioeconomic Pathways (SSP) framework indicates that BECCS is a key technology to reduce global greenhouse gas emissions (Fridahl & Lehtveer, 2018). For example, median scenarios of the SSP framework require BECCS to account for roughly 20% of the global energy production by 2100 in order to achieve climate goals. In more local terms, according to the Lawrence Livermore National Laboratory, the most economically feasible pathway for California's emissions reduction strategy is to deploy roughly 100 Mt-CO₂ per year through BECCS (Friedmann et al., 2020; Venton, 2016).

The feasibility of BECCS is highly dependent on carbon pricing (\$15-400 per tCO₂, Consoli, 2019; Fuss et al., 2018), biomass land use (30-40 million hectares/GtCO₂, Consoli, 2019), supply chain infrastructure, and CO₂ transport and injection (Kemper, 2015). One study compared CCS and BECCS for a power plant and found that a carbon tax above 23.18 €/tCO₂ was more economically favourable to BECCS (Wei et al., 2020), noting the European emission allowance CO₂ price to be 23.74 €/tCO₂ at the time. BECCS deployment requires consideration of emissions storage capacity, feedstock availability, and spill-over effects on land use and food security (Fridahl & Lehtveer, 2018). BECCS has yet to be deployed at a wide scale, and it could be difficult to do so without regulatory and institutional support (Muratori et al., 2016). However, BECCS has the potential to offset emissions from industries that face technical challenges and high costs to achieve emissions reductions (Fridahl & Lehtveer, 2018).

4. Geothermal-BECCS: Classification and Thermodynamic Model

Our proposed classification of geothermal-BECCS systems is based on two important concepts. First, biomass is used as a secondary fuel source for power generation. Second, CO₂ emissions from the biomass feedstock are sequestered via in-line dissolution within reinjection wells. Liquified or free-

phase CO₂ injection is not considered within the scope of this work, leaving sequestration capacity to be constrained by the solubility of CO₂ in reinjection fluid at dissolution conditions.

Coupling geothermal with BECCS could simultaneously increase electricity generation while creating a negative emissions profile. Such carbon negative geothermal cycles potentially improve the economic feasibility of low enthalpy geothermal systems, which could encourage further uptake of this renewable technology. The feasibility of geothermal-BECCS is likely to be dependent on the colocation of geothermal systems and available biomass feedstock, coupled with any economic benefit incurred from emissions reduction incentives.

In-line dissolution is a CCS approach that takes advantage of existing reinjection wells in a developed geothermal field. In contrast, conventional CCS will often require construction of major offsite pipe-networks and injection wells. Instead, certain on-site refurbishments, such as the bubbler or stainless-steel retrofits at certain points are required. The solubility of CO₂ in reinjection fluid depends on injectate temperature, pressure and salinity (Duan & Sun, 2003). The presence of magmatic CO₂ or H₂S in the geofluid would further reduce sequestration potential (in the event they are captured and reinjected). The CO₂ could be sequestered through mineral storage given favourable geology (Sigfússon et al., 2018), kept in solution through pressure maintenance (Kaya & Zarrouk, 2017; Kervévan et al., 2013), or some combination of both.

One practical challenge for implementing a geothermal-BECCS system as a power production and negative emissions tool is to determine an optimal plant design. To address this problem, we developed a systems model to explore the mass-energy balances and CO₂ dissolution conditions for multiple hypothetical configurations. This is the first step towards plant optimization, which is important to inform strategic decision making when maximizing thermodynamic performance and sequestration potential.

Our systems model is a modular description of geothermal-BECCS plant components that characterizes the thermodynamic phenomena that govern electricity generation, conversion

efficiency and sequestration potential. These thermodynamic phenomena will change with plant configuration, so a systems model approach is useful to compare modelled outputs. Because geothermal-BECCS systems are inherently site specific, constrained by reservoir temperature and enthalpy and available biomass, a systems model also allows for comparisons across locations.

4.1. Model Methodology

Mass and energy balances were calculated for production wells, separators, heat exchangers (preheaters, evaporators and superheaters), condensing turbines and surface pumps. For each, we assumed no uncontrolled losses in temperature and pressure. Furthermore, we assumed negligible pressure losses at valves and bends and thermal losses due to imperfect insulation or surface pumps. Model verification is provided in the supplemental index.

4.1.1. Flash Power Plant Thermodynamics

The baseline quality of a geothermal resource is determined by reservoir conditions – temperature (T_{res} , °C), pressure (P_{res} , Pa), and specific enthalpy (h_{res} , J/kg). The enthalpy of the geofluid at the wellhead (h_{wh}) is the gravity element of the water column (gL_w) subtracted from the reservoir enthalpy (DiPippo, 2016):

$$h_{wh} = h_{res} - gL_w \quad (1)$$

The gravity element will be negligible on geofluid enthalpy unless in cases where the well is very deep and low in temperature (DiPippo, 2016).

Separation of two-phase geofluid into steam and brine components depends on its enthalpy and the pressure rating of a standard vertical separator. The mass of dry steam and rejected brine are determined through conservation of mass and energy. The total geofluid mass ($\dot{m}_{wh}$) entering the wellhead separator is equal to the sum of the rejected brine mass ($\dot{m}_b$) and the mass of steam ($\dot{m}_s$) exiting the separator. Electronic equations of state are used to determine saturation enthalpies of

253 steam (h_s) and brine (h_b) at the separator pressure. Energy conservation is then expressed in heat
 254 rate form using products of mass rate and enthalpy:

$$\dot{m}_{wh} = \dot{m}_s + \dot{m}_b \quad (2)$$

$$\dot{m}_{wh} h_{wh} = \dot{m}_s h_s + \dot{m}_b h_b \quad (3)$$

255 The optimal separator temperature (T_{sep}) is found by averaging the condenser temperature (T_{cond})
 256 and the reservoir temperature (DiPippo, 2016):

$$T_{sep} = \frac{T_{cond} + T_{res}}{2} \quad (4)$$

257 In a single-stage flash plant, dry steam is dispatched immediately for (wet) expansion in a condensing
 258 turbine. The true exhaust enthalpy of steam condensate ($h_{ex,real}$) following expansion is determined
 259 using the Baumann rule (DiPippo, 2016). This requires the saturated liquid enthalpy (h_l) and the
 260 saturated vapor enthalpy (h_g), obtained at the condenser pressure:

$$h_{ex,real} = \frac{h_s - A \left[1 - \left(\frac{h_g}{h_l - h_g} \right) \right]}{1 + A(h_l - h_g)} \quad (5)$$

261 Where A is the isentropic coefficient given by:

$$A = 0.5 \eta_{TD} (h_s - h_{ex,isen}) \quad (6)$$

262 The isentropic coefficient accounts for the dry turbine mechanical efficiency (η_{TD}), assumed to have
 263 a theoretical maximum value of 85%, and requires the isentropic turbine exhaust enthalpy ($h_{ex,isen}$).
 264 As the steam expands in the turbine, mechanical work will generate power output ($\dot{W}_g$), which
 265 depends on the steam mass rate and the enthalpy drop across inlet and exhaust:

$$\dot{W}_g = \dot{m}_s (h_s - h_{ex,real}) \quad (7)$$

266 Parasitic loads ($\dot{W}_{par}$) are subtracted to obtain net saleable power ($\dot{W}_{net}$):

$$\dot{W}_{net} = \dot{W}_g - \dot{W}_{par} \quad (8)$$

Depending on the design of a hybrid geothermal-BECCS plant, separated steam ($\dot{m}_s$) could be routed to a boiler after the separation process (Equations 2 and 3) resulting in superheated steam ($\dot{m}_{shs}$). The enthalpy at the superheater outlet (h_{shs}) is a predetermined plant design parameter based on the final temperature of the superheated steam. The heating rate required for superheating ($\dot{Q}_{shs}$), is calculated as (Thain & DiPippo 2015):

$$\dot{Q}_{shs} = \dot{m}_{shs}(h_{shs} - h_s) \quad (9)$$

The biomass burn rate ($\dot{m}_{bio}$) to deliver this superheating is computed from the higher heating value of the biomass feedstock (HHV) and the efficiency of the biomass boiler (η_{Boiler}). These values are both design parameters for the plant, with the higher heating value dependant on feedstock quality.

$$\dot{m}_{bio} = \frac{\dot{Q}_{shs}}{\eta_{Boiler}HHV} \quad (10)$$

For superheated steam configurations, steam enthalpy at turbine exhaust conditions is assumed to be sufficiently high that expansion is dry (Janes, 1984):

$$h_{ex,real} = h_{shs} - \eta_{TD}(h_{shs} - h_{ex,isen}) \quad (11)$$

The enthalpy of the exhaust steam condensate is used to determine the generated and net power output of the plant using Equations 6 and 7.

To compare across different configurations how effectively a geofluid is being utilized, the exergy rate of the geothermal resource ($\dot{E}_g$) must be determined:

$$\dot{E}_g = \dot{m}_{wh}[h_{wh} - h_0 - T_0(s_{wh} - s_0)] \quad (12)$$

where h_0 , T_0 , and s_0 are the ambient enthalpy, temperature and entropy conditions, respectively, and s_{wh} is the entropy of the geofluid at the wellhead. Plant utilization efficiency (η_u) is the ratio of the net power of the plant to the exergy rate of the geofluid.

$$\eta_u = \frac{\dot{W}_{net}}{\dot{E}_g} \times 100 \quad (13)$$

For geothermal-BECCS configurations, the exergy rate of the biomass, a product of the biomass burn rate and specific exergy ($\dot{m}_{bio}e_{bio}$), also factors into the denominator of the utilization efficiency calculation:

$$\eta_u = \frac{\dot{W}_{net}}{\dot{E}_g + \dot{m}_{bio}e_{bio}} \times 100 \quad (14)$$

4.1.2. Binary Power Plant Thermodynamics

At low reservoir enthalpies, flash plants become infeasible because the majority of geofluid exergy is rejected with the separated brine. In such cases, a binary plant design might make more efficient use of these resources, and the same is true for geothermal-BECCS hybrids.

In a binary cycle, a downhole pump is used to maintain the geofluid at high-pressure to avoid flashing (DiPippo, 2016). The geofluid is therefore treated as liquid phase brine. The pump delivers the brine to an evaporator, where it heats a (usually hydrocarbon) working fluid from its liquid saturation (h_l) to vapor saturation point (h_g) at a given evaporator pressure. In a counter-flow heat exchanger, this will result in a change between the brine evaporator inlet temperature (T_x) and the brine evaporator outlet temperature (T_y). Conservation of energy during evaporator heat transfer is described:

$$\dot{m}_b \underline{c}_b (T_x - T_y) = \dot{m}_{wf} (h_g - h_l) \quad (15)$$

Where $\dot{m}_{wf}$ is the mass rate of the working fluid and $\underline{c}_b$ is the average specific heat capacity of the geofluid during the heat exchange. The properties of working fluid at these conditions were taken from Reynolds (1979).

The working fluid resides in a closed loop. After evaporation, it passes through a turbine and condenser, before reaching a surface pump to restart the loop. The working fluid enthalpy at pump exit ($h_{p,ex}$) is likely not the same as h_l , and thus a preheater is used. Geofluid exiting the evaporator can be used in a second heat transfer to preheat the compressed working fluid. The heat transfer within the preheater is also described by energy conservation:

$$\dot{m}_{b\text{C}_b}(T_y - T_z) = \dot{m}_{wf}(h_l - h_{p,ex}) \quad (16)$$

Where T_z is the final brine dispatch temperature. If the geothermal plant is designed for a specific brine dispatch temperature both the evaporator and preheater can be treated as a single thermodynamic unit:

$$\dot{m}_{p\text{C}_b}(T_x - T_z) = \dot{m}_{wf}(h_g - h_{p,ex}) \quad (17)$$

For geothermal-BECCS binary plants, the low temperature geofluid can be tasked for the heat exchange in the preheater (Equation 15). Meanwhile, the biomass can be tasked with heat exchange in the evaporator (Equation 16). The pump exit enthalpy is determined by the isentropic pump exit enthalpy ($h_{p,isen}$), the working fluid condition exiting the condenser (h_{Cond}), and the pump efficiency (η_p):

$$h_{p,ex} = h_{Cond} + \frac{h_{p,isen} - h_{Cond}}{\eta_p} \quad (18)$$

Due to the retrograde nature of common hydrocarbon working fluids in binary plants, e.g., isopentane (DiPippo, 2016), expansion is completely dry. The generated power is then dependent on the working fluid mass rate, the dry turbine efficiency, and the difference between the working fluid enthalpy at the binary turbine inlet (h_{BT}) and the isentropic turbine exhaust enthalpy ($h_{ex,isen}$), which depends on the cooling apparatus:

$$\dot{W}_g = \dot{m}_{wf} \times \eta_{TD}(h_{BT} - h_{ex,isen}) \quad (19)$$

If a portion of the heating load is taken up by the biomass boiler, then the power required for heating ($\dot{Q}_h$) is equivalent to the product of the working fluid mass rate and the change in enthalpy between inlet (h_{in}) and outlet (h_{out}) of the biomass heat exchanger. The latter is a design parameter and will be the same as the working fluid's enthalpy at the binary turbine inlet (h_{BT}). The inlet enthalpy is dependent on where the biomass heat exchanger is inserted into the cycle.

$$\dot{Q}_h = \dot{m}_{wf}(h_{out} - h_{in}) \quad (20)$$

324 The biomass burn rate can be found in a similar way as in Equation 10:

$$\dot{m}_{bio} = \frac{\dot{Q}_h}{\eta_{Boiler} HHV} \quad (21)$$

325 4.1.3. CO₂ Sequestration Capacity

326 The CO₂ sequestration rate depends on the biomass emissions rate and the reinjection fluid's carrying
 327 capacity by CO₂ dissolution. For the solubility of CO₂ in pure water, we used the chemical potential
 328 model of Duan and Sun (2003), which is a standard formulation used in geothermal-CO₂ reservoir
 329 simulators (Zyvoloski, 2007). Their model parameterizes the solubility of CO₂ in pure water (s_{CO_2}) in
 330 terms of pressure and temperature:

$$s_{CO_2} = f(P_{dis}, T_{dis}) \quad (22)$$

331 Dissolution pressure (P_{dis}) is a design parameter that is determined by both the wellhead injection
 332 pressure and the depth of the sparger (Sigfusson et al., 2015), and was set as a static condition. T_{dis}
 333 is assumed to be the final dispatch temperature of either condensate exhaust ($T_{ex,real}$) or dispatched
 334 brine (T_z), or when applicable, a mass-weighted average of both (T_{avg}).

335 The CO₂ emissions rate ($\dot{m}_{CO_2}$) depends on the biomass burn rate via the CO₂ emissions factor (X_{CO_2}),
 336 a property of stationary biofuel given in kg of CO₂ per kg of feedstock (Table 1):

$$\dot{m}_{CO_2} = X_{CO_2} \dot{m}_{bio} \quad (23)$$

337 The combined carrying capacity ($\dot{m}_{dis}$) for a geothermal-BECCS plant with brine and condensate is:

$$\dot{m}_{dis} = (\dot{m}_s + \dot{m}_b) s_{CO_2}(P_{dis}, T_{avg}) \quad (24)$$

338 For a binary cycle, the reinjection temperature is the brine dispatch temperature from the preheater
 339 (T_z). Thus, the carrying capacity is:

$$\dot{m}_{dis} = \dot{m}_b s_{CO_2}(P_{dis}, T_z) \quad (25)$$

The sequestration rate ($\dot{m}_{seq}$) is limited by the carrying capacity of the reinjected geofluid, and thus constrained as:

$$\dot{m}_{seq} = \min(\dot{m}_{dis}, \dot{m}_{CO_2}) \quad (26)$$

Because geothermal-BECCS systems would be balanced by both power production and negative emissions objectives, it is important to contextualize the sequestration rate in terms of the plant's power generation. For this purpose, we define levelized annual sequestration (LAS) as the ratio of annual sequestration and power plant output, in tonnes/year/kWe. It is calculated by converting the sequestration rate from 1 kg/s to 31,536 tonnes per year and dividing by the plants power output:

$$LAS = \frac{\dot{m}_{seq}}{\dot{W}_{net}} \times 31,536 \quad (27)$$

Finally, to compare geothermal-BECCS configurations to other energy cycles, the annual emissions intensity (EI) factor can be expressed in gCO₂/kWh by converting LAS (1 million grams per tonne divided by 8760 hours in a year).

$$EI = LAS \times 114.16 \quad (28)$$

Emissions intensities are usually used for carbon positive plants such as natural gas based power plants. If the operational emissions of a plant are carbon neutral, EI is assumed to be 0 gCO₂/kWh in this study. If the operational emissions of a plant are net negative atmospheric, EI is expressed as a negative value. The entire life-cycle emissions (construction, magmatic CO₂, fuel transport, etc.) of a plant should be factored into the EI during a practical application.

4.2. Model assumptions

To enable comparison across different plant configurations, we have used reasonable parameters for the geothermal apparatus (Table 1) and fixed these values across configurations wherever possible. However, any practical application of this technology would likely require apparatus optimization to site-specific conditions.

We have considered four different Geothermal-BECCS configurations in this study. These hybrids include a flash plant (Configuration 1), an ORC binary plant (Configuration 2), a compound flash-binary plant (Configuration 3), and a preheat system (Configuration 4). These configurations were compared to non-hybrid conventional configurations of flash (Benchmark A) and ORC binary (Benchmark B) geothermal plants, and a standalone bioenergy based thermal plant (Benchmark C). The model results for all configurations and benchmarks are presented in Table 2.

All configurations consider a geothermal doublet comprising one production well and one reinjection well. A unit mass rate (1 kg/s) of geofluid is taken from a reservoir at the low temperature threshold of 160°C (Hochstein, 1990), an initial pressure of 50 bar, and a corresponding enthalpy of 678 kJ/kg. This allows for all model outputs to be evaluated on a per mass rate of geofluid basis and to be scaled to plants of different size. Scaling of infrastructure and costs are not considered here.

A reservoir pressure of 50 bar is representative of the hydrostatic pressure in a 500 m deep well with a water table close to the surface. This is a reasonable estimate for geothermal reservoirs in Aotearoa New Zealand (Quinao & Zarrouk, 2018). Geofluid pressure at the wellhead is typically optimized using productivity curves (DiPippo, 2016), but for simplicity we have assumed 18 bar if a downhole pump is operating to keep the geofluid well below the liquid saturation curve. Where relevant, the wellhead pressure is the pressure rating of the wellhead separator (derived from Equation 4).

Table 1: Initial properties for all modelled configurations

Parameter	Value
Geofluid Mass Rate (kg/s)	1
Reservoir Temperature (°C)	160
Reservoir Pressure (bar)	50
Dry Turbine Efficiency (%) ^I	85
Generator Efficiency (%) ^{II}	95

Boiler Efficiency (%) ^I	80
Specific Heat Capacity of Water (kJ/kgK) ^{II}	4.19
Water Condenser Pressure (bar) ^{II}	0.09
Isopentane Condenser Pressure (bar) ^{II}	1.87
Woody Biomass Higher Heating Value (kJ/kg) ^I	15350
Woody Biomass Specific Exergy (kJ/kg) ^I	16500
Biomass CO ₂ Emissions (kg/kg-biomass) ^{III}	0.862

^I(Thain & DiPippo, 2015)

^{II}(DiPippo, 2016)

^{III}(Bioenergy Association, 2019)

378 All configurations were modelled as pure water for simplicity in conceptualizing the energy cycle, with
379 no magmatic origin CO₂ or mineral salinity. In the past, reinjection of magmatic CO₂ led to severe
380 oxygen corrosion at the Coso geothermal field, USA due to chemical contact between condensate and
381 air in direct contact condensers (Bonafin et al., 2019). Thus, we have opted to model surface
382 condensers, which are essentially shell and tube heat exchangers that condense steam by inducing
383 heat transfer (DiPippo, 2016), as a safeguard against oxygen corrosion. In practice, this would require
384 a separate source of coolant. We assumed a condenser pressure for water cooling at 0.09 bar (DiPippo
385 2016). For relevant configurations, the temperature of superheated water was set to 500°C, typical of
386 fossil-based geothermal hybrids investigated previously (Kestin et al., 1978; Khalifa et al., 1978). This
387 is a design parameter that would generally be constrained by apparatus material, cooling load and
388 reheating strategy.

389 For ORC binary configurations, isopentane (Reynolds, 1979) was used as the working fluid. A typical
390 condenser pressure of 1.866 bar was assumed (DiPippo, 2016). The ambient/dead-state conditions
391 for each benchmark and configuration was assumed to be 1 bar and 25°C. Ambient conditions in
392 practice are site specific and vary by time of day and season.

The biomass feedstock was assumed to be forestry waste with higher heating value of 15350 kJ/kg and a specific exergy of 16500 kJ/kg (Thain & DiPippo, 2015) from the Kaingaroa Forest, Aotearoa New Zealand. All combustion emissions from this feedstock were treated as CO₂ at a value of 0.862 kg per kg of feedstock (Bioenergy Association, 2019). We assumed a dry turbine efficiency of 85% (the mechanical maximum), as well conservative values for generator and boiler efficiency of 95 and 80%, respectively.

The emissions for each configuration were compared to the solubility of CO₂ in water at the intrinsic reinjection temperature and a dissolution pressure of 50 bar. Because an interior pipe and sparger is used for in-line dissolution, this dissolution pressure is not based solely on wellhead pressure, but also the hydrostatic pressure of the reinjection column at the depth that the CO₂ exits into the exterior well. We believe 50 bar is a reasonable assumption because the sparger depth was between 330-360m and the injection pressure between 20-25 bar at the CarbFix pilot study in Hellisheidi, Iceland (Sigfusson et al., 2015).

Reinjection temperatures for geothermal plants are optimized to maximize exergetic use while avoiding the precipitation of silica. Despite using a pure water model, we opted to design a reinjection temperature that would be consistent with analogous plants in the New Zealand. For example, the test plant program at the Ngatamariki geothermal field had a preheater exit brine temperature of 90°C (Addison et al., 2015a). Despite the brine having a silica saturation index (SSI) of ~1.9, injection wells showed an increase in injectivity with no signs of scaling after one year. Thus, all geothermal-BECCS configurations were designed to have an average reinjection temperature of 95°C, allowing for dissolution conditions for CO₂ to be consistent. The solubility of CO₂ at these reinjection conditions is 0.021 kg per kg of water (2.1 wt%).

Because of the small scale of the modelled configurations, parasitic loads (i.e. lighting, coolant load, operational loads, etc.) were assumed negligible. Two important parasitic loads, (1) the work required to compress biogenic CO₂ for suitable in-line dissolution and (2) the work to compress working fluid in

closed Rankine cycles, are demonstrated for a geothermal-BECCS preheat system in Appendix B and C respectively. For a fully sized plant, the optimization of all parasitic loads would need to be considered based on economic analysis.

4.2.1. Benchmark plants

For Benchmark A (Figure 2A), a geothermal flash plant with a condenser pressure of 0.09 bar drawing 1 kg/s of geofluid from a reservoir at 160°C would have an optimized separator temperature of 102°C (Figure 2B), corresponding to a pressure rating of 1.1 bar. A mass rate of 0.11 kg/s of steam is separated with an enthalpy of 2679 kJ/kg at the turbine inlet. The condensate and brine are returned to a single reinjection line at 95°C.

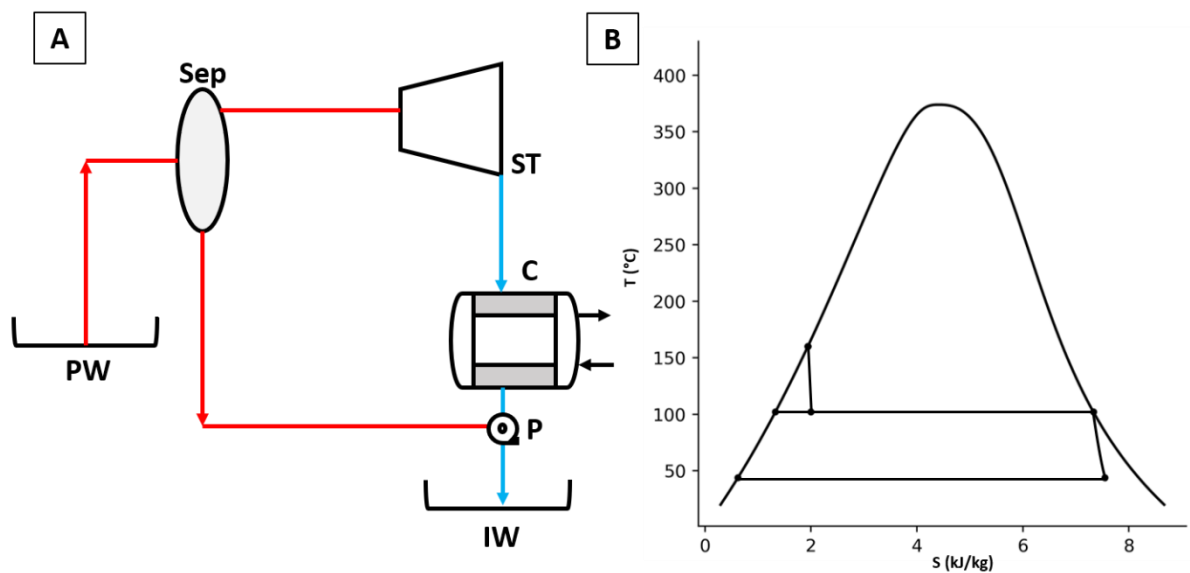


Figure 2: Schematic (A) and temperature-entropy (T-S) process diagram (B) for Benchmark A. PW = Production Well, Sep = wellhead separator, ST = steam turbine, C = condenser, IW = Injection well, P = surface pump. Red-line = hot geofluid, blue-line = cold geofluid.

For Benchmark B (Figure 3A), 1 kg/s of geofluid at 160°C from the reservoir is pumped at 18 bar to an evaporator and preheater. At a turbine inlet pressure of 18 bar, the enthalpy of the isopentane is 733 kJ/kg (Figure 3B). The geofluid transfers enough heat to be cooled down to 95°C before being

reinjected. The mass rate of isopentane required is thus 0.57 kg/s. The full working fluid cycle is given in Table A.1 in Appendix A.

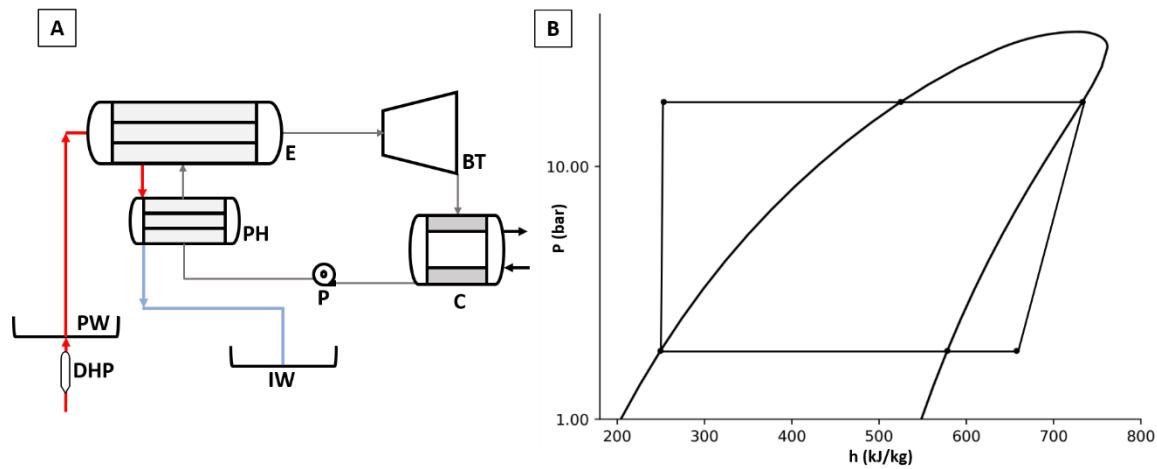


Figure 3: Schematic (A) and pressure-enthalpy (P-h) process diagram (B) for Benchmark B. DHP = downhole pump, PW = Production Well, E = evaporator, PH = preheater, BT = binary turbine, C = condenser, IW = Injection well, P = surface pump. Red-line = hot geofluid, blue-line = cold geofluid, grey-line = working fluid (isopentane).

For Benchmark C (Figure 4A), no geofluid is extracted. Instead, a standalone biomass-based powerplant is modelled with a closed Rankine cycle using distilled water as the working fluid. A biomass boiler using wood waste heats distilled water to superheated steam at 500°C (Figure 4B). The steam passes through a turbine at 18 bar before being condensed to 0.09 bar. The mass rate of working fluid was 0.39 kg/s (consistent with Configuration 4 introduced later), requiring a biomass burn rate of 0.11 kg/s.

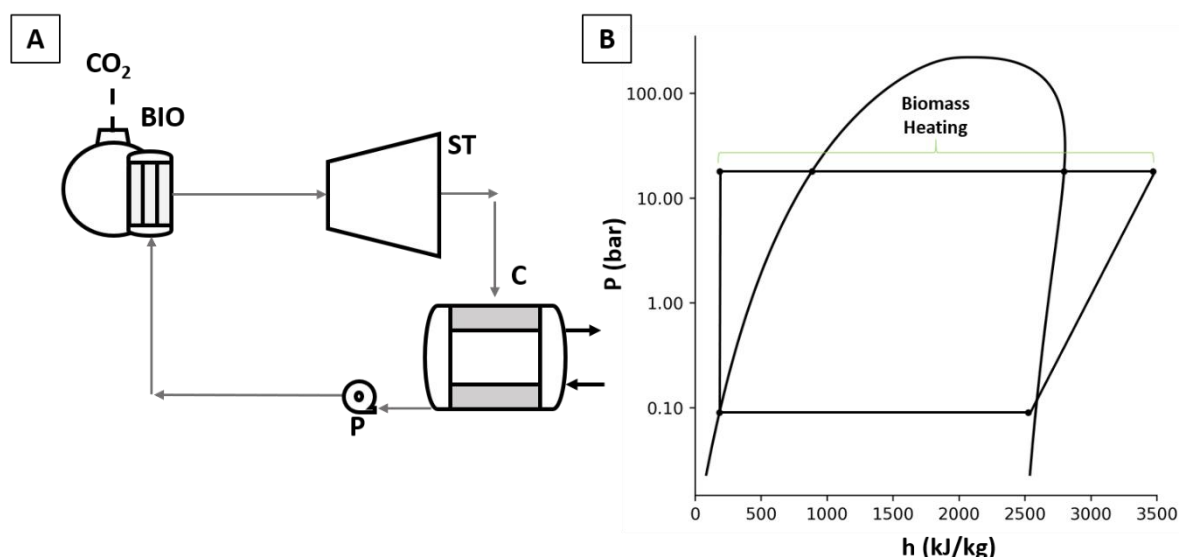


Figure 4: Schematic (A) and pressure-enthalpy (P-h) process diagram (B) for Benchmark C. BIO = biomass boiler, ST = steam turbine, C = condenser, P = surface pump. Black-dotted line = CO₂, grey-line = working fluid (distilled water).

The mass rate of flue CO₂ is 0.09 kg/s with an emissions intensity of 0 g/kWh due to the carbon-neutral nature of the biomass. It is assumed that the boiler is equipped with all standard apparatus (i.e. furnace, steam drum, etc.). The full working fluid cycle is given in Table A.2 in Appendix A.

None of the benchmarks were modelled with in-line dissolution of biogenic CO₂; Benchmark A and B had no biomass use and thus no biogenic CO₂ emissions. Benchmark C did not have the geothermal reinjection infrastructure to facilitate in-line dissolution.

4.3. Geothermal-BECCS configurations

4.3.1. Configuration 1 – Geothermal-BECCS Flash Plant

Based on Benchmark A, a biomass boiler is inserted into the steam line between the wellhead separator and the turbine (Figure 5A). The 0.11 kg/s of steam is superheated from the separator temperature of 102°C to 500°C (Figure 5B) with an enthalpy increase from 2679 kJ/kg to 3488 kJ/kg. The biomass burn rate required to accomplish this is 0.008 kg/s, resulting in 0.007 kg/s of CO₂ emissions which is sent to the reinjection well.

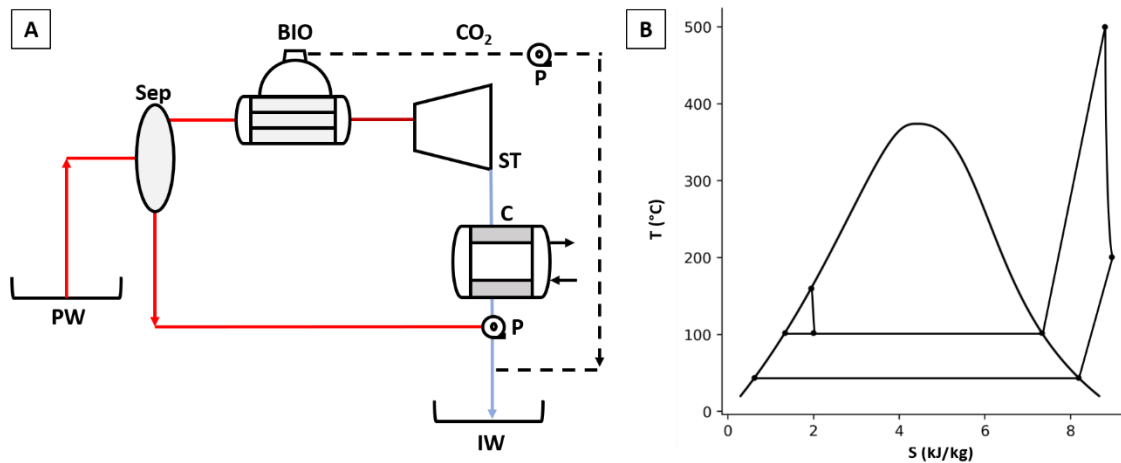


Figure 5: Schematic (A) and temperature-entropy (T-S) process diagram (B) for Configuration 1. PW = Production Well, Sep = wellhead separator, ST = steam turbine, C = condenser, IW = Injection well, P = surface pump, BIO = biomass boiler. Red-line = hot geofluid, dark red-line = superheated steam, blue-line = cold geofluid, dotted-black line = CO₂.

4.3.2. Configuration 2 – Geothermal-BECCS ORC Binary Plant

Based on Benchmark B, the 1 kg/s of geofluid is relegated to the preheating process while the working fluid is heated in the evaporator by the biomass (Figure 6A). The turbine inlet enthalpy of the isopentane is kept at the saturated vapor condition at 18 bar (733 kJ/kg), meaning more working fluid was required. This setup was chosen rather than simply superheating the isopentane past the vapor saturation point due to the retrograde nature of the working fluid (Figure 6B), likely resulting in very high enthalpy isopentane in the turbine exhaust. This new working fluid mass rate was ~1 kg/s. To heat the working fluid from the saturated liquid state to saturated vapor, 0.018 kg/s of biomass was required with 0.016 kg/s of CO₂ sent to the reinjection well. The full working fluid cycle is given in Table A.3 in Appendix A.

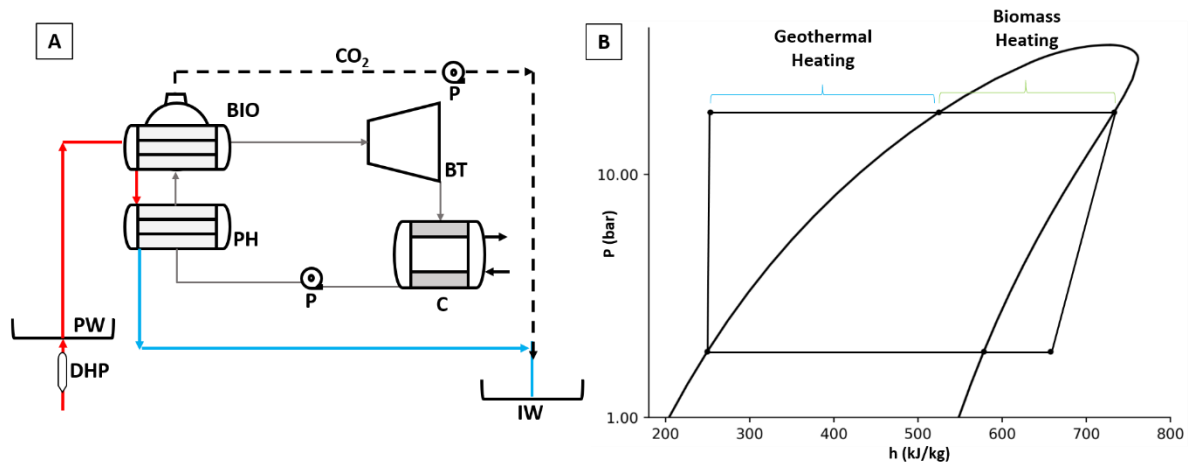


Figure 6: Schematic (A) and pressure-enthalpy (P-h) process diagram (B) for Configuration 2. DHP = downhole pump, PW = Production Well, PH = geothermal preheater, BT = binary turbine, C = condenser, IW = Injection well, P = surface pump, BIO = biomass boiler. Red-line = hot geofluid, blue-line = cold geofluid, grey-line = working fluid (isopentane), dotted-black line = CO₂.

4.3.3. Configuration 3 – Geothermal-BECCS Compound Flash-Binary Plant

Like historically proposed geothermal-fossil (DiPippo et al., 1978) and geothermal-solar hybrid designs (Greenhut et al., 2010), Configuration 3 maximizes the effective heat of the biomass by compounding both a flash portion and ORC binary portion into a single electricity generation cycle (Figure 7A).

1 kg/s of geofluid is pumped to the surface at 18 bar before entering a boiler, where it is heated to the liquid saturation point by the biomass, 207°C. This point was chosen because it requires the minimum biomass heating, with a biomass burn rate of 0.018 kg/s and 0.015 kg/s of CO₂. The heated geofluid then enters a cyclone separator, optimized to 126°C and 2.4 bar. A mass rate of steam of 0.16 kg/s then passes through a steam turbine and is condensed to 0.09 bar (7B).

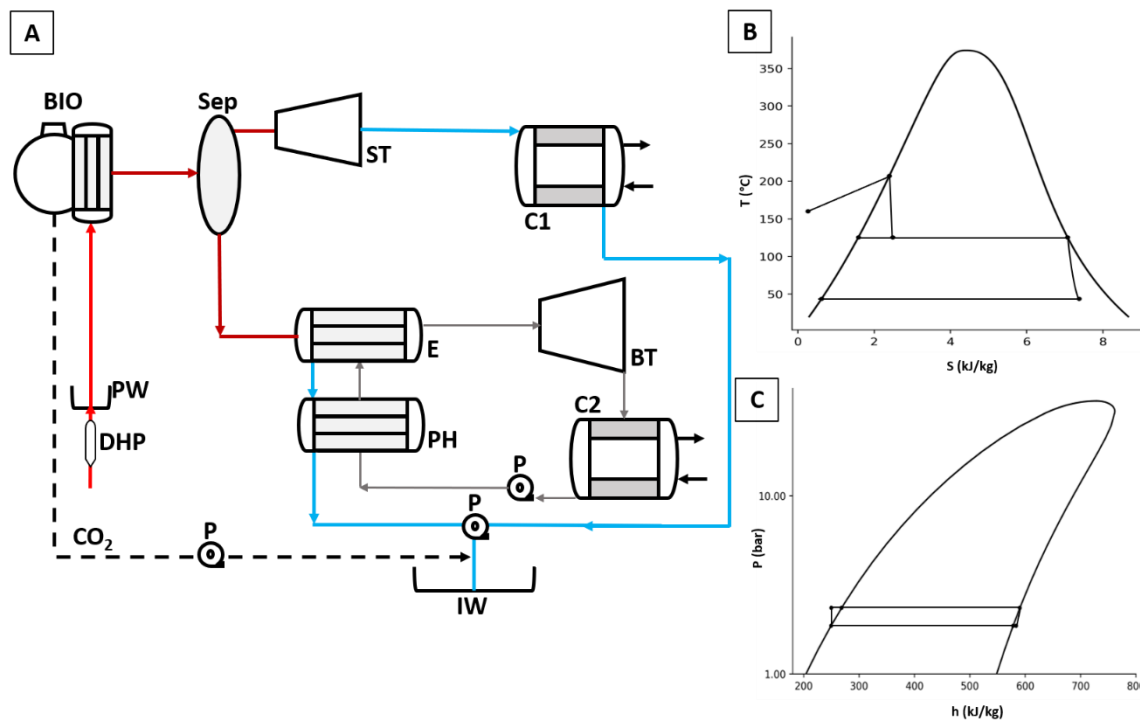


Figure 6: Schematic (A), temperature-entropy (T-s) process diagram (B) and pressure-enthalpy (P-h) process diagram (C) for Configuration 3. DHP = downhole pump, PW = Production Well, BIO = biomass boiler, Sep = cyclone separator, ST = steam turbine, C1 = condenser 1, C2 = condenser 2, E = Evaporator, PH = preheater, BT = binary turbine, IW = Injection well, P = surface pump. Red-line = hot geofluid, blue-line = cold geofluid, grey-line = working fluid (isopentane), dotted-black line = CO₂.

The remainder of the brine (0.84 kg/s) transfers heat to isopentane via an evaporator and preheater, set to the separator pressure (Figure 7C). The enthalpy and mass rate of the isopentane at the binary turbine inlet are 590 kJ/kg and 0.21 kg/s respectively. The preheater exit temperature of the brine is 105°C with the average reinjection temperature of the brine and condensate mixture at 95°C. The working fluid cycle for the binary portion of the schematic is given in Table A.4 in Appendix A.

4.3.4. Configuration 4 – Geothermal-BECCS Preheat System

Based on Benchmark C and fossil based geothermal hybrids (Kestin et al., 1978; Parsons, 1978), Configuration 4 also has closed Rankine cycle with distilled water that is primarily heated by the

biomass feedstock (Figure 8A). However, 1 kg/s of low temperature geofluid (160°C) is pumped to 18 bar and used to preheat the working fluid from the condenser temperature (44°C) to the saturated liquid condition (207°C, 2796 kJ/kg).

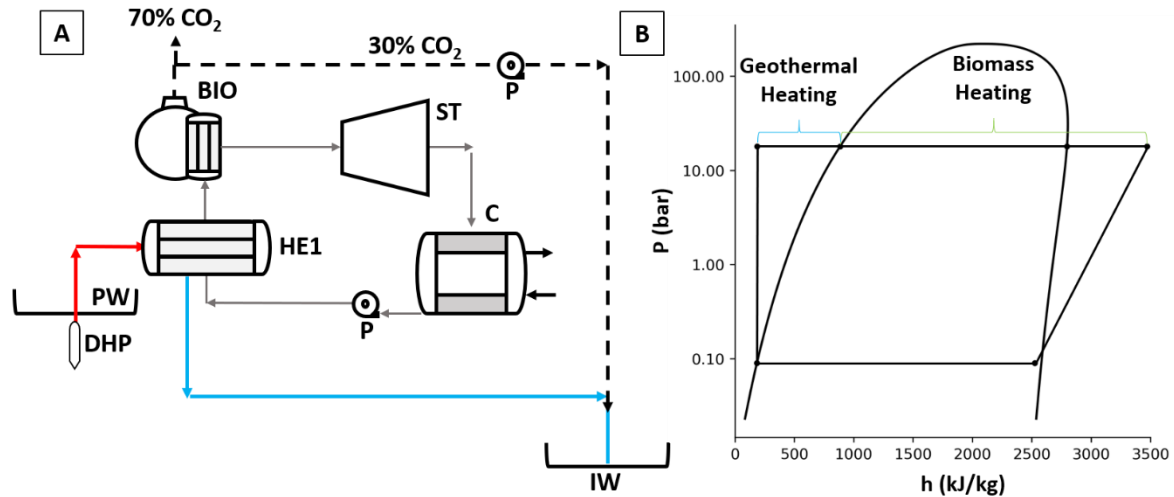


Figure 8: Schematic (A) and pressure-enthalpy (P-h) process diagram (B) for Configuration 4. DHP = downhole pump, PW = Production Well, HE1= geothermal preheater, ST = steam turbine, C = condenser, IW = Injection well, P = surface pump, BIO = biomass boiler. Red-line = hot geofluid, blue-line = cold geofluid, grey-line = working fluid (distilled water), dotted-black line = CO₂.

Because it is not retrograde by nature, superheating distilled water is typically deployed by conventional thermal plants (DiPippo, 2016; Kestin et al., 1978). Thus, the remainder of the heating (500°C, 3470 kJ/kg) is done by the biomass (Figure 8B), requiring a burn rate of 0.082 kg/s and resulting in 0.072 kg/s of CO₂ emissions. With a preheater exit temperature of 95°C for the geofluid, the mass of working fluid was 0.39 kg/s. The full working fluid cycle is given in Table A.5 in Appendix A.

5. Results and Discussion

5.1. Geothermal-BECCS comparative power and sequestration performance

Model results for all configurations are summarised in Table 2. All results are given on a per unit mass rate (1kg/s) of geofluid to facilitate scalability. The base case flash plant (Benchmark A) and binary plant (Benchmark B) generated 32 KWe and 43 KWe at 6 and 8% utilization efficiency, respectively.

The geothermal-BECCS flash plant (Configuration 1) generated 64 kWe, twice that of the flash benchmark (Benchmark A). The geothermal-BECCS ORC binary plant (Configuration 2) generated 76 kWe, which is 77% higher than the binary benchmark (Benchmark B). Both configurations 1 and 2 had a utilization efficiency of 9%, surpassing their respective benchmarks, A and B.

The geothermal-BECCS compound flash-binary plant (Configuration 3), at 62 kWe, also surpassed benchmarks A and B but had similar or lower power than configurations 1 and 2. Its utilization efficiency, 7%, was also lower than configurations 1 and 2. It exceeded the benchmark flash plant by only a single percent despite generating almost double the power. Configuration 1 had the lowest biomass burn rate at 0.008 kg/s. Configurations 2 and 3 had an equivalent amount at 0.018 kg/s.

The geothermal-BECCS preheat plant (Configuration 4) and Benchmark C both generated 368 kWe, which is much higher than the other configurations and benchmarks. Additionally, they had higher utilization efficiencies at 19% and 20%, respectively. Only 74% of the biomass burn rate was needed for Configuration 4 as compared to Benchmark C. Thus, in terms of power production, all geothermal-BECCS hybrid designs were improvements over the low temperature geothermal benchmark plants. The use of low temperature geofluid for preheating for a biomass plant traded one percent in utilization efficiency for a 26% reduction in feedstock.

Table 2: Model results for all configurations, per 1 kg/s of produced geofluid

All Configuration and Benchmark Results

Values	A	B	C	1	2	3	4
Biomass Burn Rate (kg/s)	-	-	0.111	0.008	0.018	0.018	0.082
Flue CO ₂ Emissions (kg/s)	-	-	0.097	0.007	0.016	0.016	0.072
Geofluid Exergetic Power (kWth)	561	561	-	561	561	561	561
Biomass Exergetic Power (kWth)	-	-	1834	130	297	299	1353
Generated Power (kWe)	32	43	368	64	76	62	368
Utilization Efficiency (%)	6	8	20	9	9	7	19
Sequestration Efficiency (%)	-	-	-	100	100	100	30
Gross Annual Sequestration (tonnes/year)	-	-	-	217	501	501	675
Levelized Annual Sequestration (tonnes/year/kWe)	-	-	-	3.4	6.6	8.1	1.8

549 Each configuration has variable CO₂ emission rates, depending on the specific bioenergy requirements

550 (Table 2). We compared these emissions against the dissolved CO₂ carrying capacity of the unit mass

551 of geofluid at dissolution conditions (50 bar, 95°C, pure water), which allowed us to quantify a

552 sequestration rate for each configuration. The solubility of CO₂ at the dissolution conditions is 0.021

553 kg per kg of water. Configurations 1, 2 and 3 had biogenic CO₂ emissions of 0.007, 0.016 and 0.016

554 kg/s respectively, and were all able to sequester 100% of their respective biogenic CO₂ emissions.

555 Configuration 4 had an emissions rate of 0.072 kg/s that exceeded the sequestration capacity of the

556 reinjected brine. Only 30% of the total biogenic emissions could be sequestered. What should be

557 noted though is that emissions uncaptured can be considered carbon neutral. When compared to

Benchmark C, which would have carbon neutral emissions of 0.097 kg/s, Configuration 4 had 0.051 kg/s of carbon neutral emissions and 0.021 kg/s of carbon negative emissions.

To enable comparison between the different geothermal-BECCS configurations as negative emissions systems, we defined two sequestration performance metrics. The first is annual gross sequestration (AGS), which is the maximum reinjected mass of CO₂ in one year per unit mass rate of geofluid. The second metric is the levelized annual sequestration (LAS), which is the ratio of gross annual sequestration and generated power. The latter metric recognizes that the geofluid has a dual role: for electricity generation and as a vector for sequestering emissions. When considering the gross annual sequestration of each geothermal-BECCS configuration, Configuration 4 would sequester the highest amount of biogenic CO₂ at 675 tonnes/year, followed by Configurations 2 and 3 with 501 tonnes/year, then Configuration 1 at 217 tonnes per year. By levelizing these values by the plant's respective power output, we observe that Configuration 3 would have the highest levelized annual sequestration at 8.1 tonnes/year/kWe, followed by Configuration 2, 1 and 4 at 6.6, 3.4 and 1.8 tonnes/year/kWe respectively.

Both gross annual sequestration and levelized annual sequestration can be scaled to assess the performance or demands of specific site designs such as the geofluid and biomass requirements. For example, if Configuration 4 was scaled to a 100 MWe plant, it could theoretically sequester 0.18 MtCO₂ per year. The corresponding geofluid demand is 271 kg/s (23 kt/day); for reference, mass take from the Wairakei geothermal field (175 MWe) in Aotearoa New Zealand is 245 kt/day (Wymer & Nicholson 2014). The required biomass burn rate to achieve 100 MWe is 22 kg/s (1.9 kt/day).

To achieve the same nameplate capacity of 100 MWe with Configuration 3, 1613 kg/s (129 kt/day) of geofluid and 29 kg/s (2.5 kt/day) of biomass is required. This plant would be able to sequester 0.8 MtCO₂ per year. Expressed in reverse, to sequester 1 MtCO₂ per year, Configuration 3 would have to be rated to 124 MWe and Configuration 4 would have to be rated to 545 MWe. In practice, the available geothermal and biomass resources must first be estimated before a plant can be sized.

Finally, to lend context to geothermal-BECCS systems as negative emissions tools, it is helpful to compare the emissions intensity values of different operating plant types (Table 3). Due to the small scale of the theoretical configurations, only operational emissions are shown. Practical implementation of geothermal-BECCS would require consideration of full life cycle emissions.

Table 3: Emissions intensity for all configurations, per 1 kg/s of produced geofluid

Operating Plants	Emissions Intensity (gCO ₂ e/kWh)	Geothermal-BECCS Configuration	Emissions Intensity (gCO ₂ e/kWh)
Coal (2021 US Average) ¹	1012	1	-386
Natural Gas (2021 US Average) ¹	413	2	-753
Petroleum (2021 US Average) ¹	966	3	-922
Ohaaki Flash Plant (2019) ²	299	4	-209
Ngāwhā Binary Plants (2019) ²	312		
Geothermal (2019 NZ Average) ²	73		

1: (EIA, 2021)

2: (McLean et al., 2020)

All plant configurations offset more emissions than output by the average geothermal plant in Aotearoa NZ and configuration 2 and 3 offset more emissions per unit energy than the average (US) natural gas power plant emits (Table 3). Configuration 3 could almost offset emissions at a rate equivalent to those produced by petroleum and coal-based power plants. Even though Configurations

4 and 1 had the lowest negative emissions intensity of the geothermal-BECCS configurations, they were still able to offset roughly 51% and 93% of the emissions rate of a natural gas power plant. Thus, the sustainability potential of geothermal-BECCS has been quantified in two ways: boosted renewable power can help support an energy matrix less reliant on fossil fuels, and heavy carbon emitters could be offset by negative emissions.

5.2. Opportunities for geothermal-BECCS

Geothermal-BECCS can potentially be a negative emissions tool that not only avoids an energy penalty but also contributes to an energy gain. The efficacy of geothermal-BECCS to offset CO₂ emissions is increased when noting that sequestration is complimented by renewable electricity generation. Geothermal energy can reduce reliance on traditional fossil fuels, curtailing future emissions, while the BECCS component contributes to negative emissions. The two fundamental technologies that form the basis of a geothermal-BECCS system – biomass hybridization (Dal Porto et al., 2016) and in-line dissolution of CO₂ (Berstad & Nord, 2016; Sigfússon et al., 2018) – are pre-existing technologies in the geothermal industry, offering favourable prospects for the technical feasibility of geothermal-BECCS systems.

As a subset of BECCS technology, the gross sequestration from geothermal-BECCS systems could help achieve national and global emissions reduction targets. As an offset technology, it could be used by other industries that are unable to facilitate quick emissions reductions. As per AR5 and the SSP framework (Kemper, 2015), the economic viability of BECCS technologies is an important factor in global emissions reduction targets.

The requirement for reinjection is an intrinsic cost of developing most geothermal systems, independent of any potential sequestration activities. Using in-line dissolution offers some flexibility to the dissolution pressure, depending on the depth of the sparger and negates the need for transporting the CO₂ offsite (Kervévan et al., 2017). Thus, geothermal-BECCS does not suffer the same infrastructure penalties as conventional CCS, notably, the high capital costs of single-purpose deep-

targeting wells. This is because existing reinjection wells can be leveraged if retrofitting an existing geothermal plant, as was the case in Hellisheidi (Sigfússon et al., 2018). In the case of a new development, potential revenues from the increased conversion efficiency and saleable power (Dal Porto et al., 2016) could reduce the time taken to recover well drilling costs.

A spill-over benefit of geothermal-BECCS is improved commercial access to low enthalpy geothermal systems that might otherwise be uneconomic. These systems comprise the majority of classified geothermal resources worldwide (Franco & Villani, 2009; Hochstein, 1990), and hence a massive untapped opportunity for reliable electricity generation. Geothermal-BECCS also contributes to de-risking geothermal resource development on an individual well basis. This is because the temperature threshold for a feasible conversion efficiency is much lower in hybrid cycles that can compensate cooler fluids with increased biomass burn. Geothermal wells are particularly expensive to drill through volcanic rock, often in inaccessible or difficult terrain (Witter et al., 2019).

Typical well costs range between USD 4 million (Thorhallsson & Sveinbjornsson, 2012) to 6 million (Kipsang, 2015), upwards of 40% of the total resource investment (Thorhallsson & Sveinbjornsson, 2012), so the possibility of a low temperature well typically presents a significant project risk. However, a geothermal-BECCS configuration rebalances the value of a well towards its fluid productivity – its ability to take or receive geofluid – and de-emphasizes the energy content of that fluid. Additionally, there is the opportunity to establish new feasibility thresholds for well depth and temperature during exploration.

Geothermal-BECCS could potentially be deployed to retrofit existing plants. By increasing utilization efficiency through geothermal-BECCS, an underperforming plant could meet its nameplate capacity with a smaller mass intake. This could reduce the number or uptake rate of new production wells, as was the case for the geothermal-biomass hybrid Cornia-2 (Dal Porto et al., 2016). There are also environmental benefits to lowering mass extraction, including mitigation of subsidence and the preservation of natural surface manifestations (DiPippo, 2016).

Another retrofit opportunity is for biomass plants operating in proximity to low to medium temperature geothermal resources whose geofluid could be used for preheating and sequestration. This would both reduce biomass feedstock required and create negative emissions.

5.3. Practical Challenges for implementing geothermal-BECCS

In practice, there will also be economic, engineering and reservoir management constraints to be considered for any geothermal-BECCS design. First, direct superheating geothermal steam may require certain engineering solutions to avoid corrosion arising from exposure of magmatic H₂S and mineral deposition (Dal Porto et al., 2016; DiPippo et al., 1981). This can be addressed through separation of these elements prior to superheating or by lining with corrosion resistant tubing. Further, the corrosive potential of carbonated water will require stainless steel piping (Sigfússon et al., 2018), particularly in the reinjection well. Configurations 2 and 4 could mitigate scaling issues by ensuring brine remains below the liquid saturation point throughout the cycle. If a direct-contact condenser is part of an existing flash plant, caution must be exercised during retrofit to avoid catastrophic corrosion due to oxygen exposure (Bonafin, 2019).

The presence and scaling of mineral particulate can provide challenges at both ends of the doublet. Scaling within the tubing coils can be offset by scrubbing or implementing a mixer between superheated steam and low chloride steam (Dal Porto et al., 2016). The mineral particulate retained in brine streams could reduce the dissolution capacity within the reinjection fluid (Duan & Sun, 2003). Thus, extensive site-specific analysis regarding these minerals – as well as NCGs, another constraint on dissolution space – must be conducted to appropriately assess the technical feasibility of a given geothermal-BECCS system.

As an example, geofluid from the Rotokawa geothermal field in Aotearoa New Zealand can have up to 0.35 wt% of magmatic CO₂ (Addison et al., 2015b). For Configuration 4, which operates with biogenic CO₂ exceeding dissolution capacity, this represents an approximately 17% penalty to total sequestration. In contrast, for Configuration 3, after dissolving biogenic CO₂ (1.6 wt%), there remains

sufficient dissolution capacity in the reinjectate (2.1 wt% total, 0.5 wt% remaining) to also include the magmatic CO₂, assuming it has been captured. Mineral salinity of the brine has an even lesser effect. For a highly concentrated brine with Cl at 1500 ppm, a modified solubility calculation from Duan and Sun (2003) indicates that only about 0.5% of the total CO₂ dissolution capacity would be lost.

Reservoir modelling and field management would be a crucial component for maintaining CO₂ storage. Further research into the potential for mineralization, the risks of CO₂ leakage, pressure maintenance and chemical breakthrough must also be undertaken on a site-specific basis. For example, a decline in reservoir pressure could induce the formation of a buoyant free-phase of CO₂, which then poses a leakage risk (Kaya & Zarrouk, 2017). Reservoir studies would need to be conducted at prospective geothermal-BECCS fields to understand storage security, changes to the permeability structure and flow controls of the geothermal system due to mineralization of CO₂ and acidification of injectate, and the time scale that CO₂ may migrate towards the depressured production zone.

The overall field reinjection strategy will need to be considered when designing the BECCS component, to avoid negative impacts on the life cycle of the geothermal system. Injection trials for dissolved CO₂ may be useful to determine the permanent sequestration capacity of a specific geothermal field.

Proximity to sustainable biomass fuel sources will be a limiting factor for geothermal-BECCS deployment. Colocation of resources has been noted as a common prerequisite for previous feasibility studies of geothermal hybrids (Bruhn, 2002; Dal Porto et al., 2016; DiPippo, 2016; DiPippo et al., 1981; DiPippo & Thain, 2015; Janes, 1984; Manente et al., 2011). Sourcing the feedstock with sustainable biomass options that have a favourable CO₂ life cycle within the timeframe of global climate targets is likely a key design consideration. Thus, balancing colocation and infrastructure requirements could be a significant aspect in determining feasibility.

5.4. Future economic analysis of geothermal-BECCS

Since economic analysis is as important as thermodynamic synergy when determining feasibility of a practical geothermal-BECCS systems, there is more work to be done. A more holistic comparison of the different plant schematics could be obtained from economic analysis of the configurations described herein. For example, the levelized cost of electricity (LCOE) and the levelized cost of sequestration (LCOS) for the different configurations could supplement the thermodynamic and sequestration outputs expressed in this work.

Once these are attained, subsequent techno-economic optimization could aid strategic decision making at a prospective site. These decisions could include planning a new site, retrofitting an existing plant operating below design capacity, or improving utilization efficiency once a geothermal-BECCS hybrid is operational. For example, Configuration 4 most resembles the example of geofluid being used for feed-water heating in a conventional fossil plant, which has been identified as the most economically feasible method for geothermal-fossil hybrids in the past (Bruhn, 2002; Contractor & Burbank, 1977). While the configuration had the highest utilization efficiency of geothermal-BECCS configurations at 19%, only a simplified design is presented in this work, with more complex utilization likely able to improve power production. Model improvements to this configuration could include optimization for reheat or stream extraction strategies.

Configuration 1 could be used in retrofit of a flash plant below design capacity, similar to the Cornia-2 power plant in Lardarello, Italy (Dal Porto et al., 2016). The final superheated steam temperature would be designed with the abrasive materials in the geofluid in mind. Configuration 1 had a high exhaust steam temperature (Figure 5B), which could be used to heat additional binary units as was proposed in the Rotokawa case study (Thain & DiPippo, 2015).

The integration of carbon price, localized emissions reduction incentives and other externalities could further encourage development of geothermal-BECCS systems with near-favourable market conditions. Identifying pathways to maximize renewable power, minimize LCOE/LCOS and meet climate targets could inform stakeholders, investors and policymakers.

6. Conclusion

We introduced the concept of a geothermal-BECCS system, which combines biomass hybridization of geothermal electricity production and in-line CO₂ dissolution. Both technologies have been individually demonstrated on a practical scale in the geothermal industry. To test the thermodynamic feasibility of the concept, we developed a systems model for four geothermal-BECCS plant configurations at a hypothetical geothermal field with 1 kg/s geofluid intake. The use of a unit mass rate of geofluid allows the results for individual cycles to be scaled up to a nominal size. For a reservoir at 160°C and enthalpy of 678 kJ/kg, a benchmark flash plant with a separator pressure of 1.1 bar (Benchmark A) produced 32 kWe at 6% utilization efficiency. A benchmark binary plant with an organic working fluid cycle at 18 bar (Benchmark B) produced 43 kWe at 8% utilization efficiency.

All geothermal-BECCS configurations for the same reservoir, using forestry waste as feedstock, demonstrated improved power production over both Benchmarks A and B; 64 kWe for hybrid flash plant (Configuration 1), 76 kWe for hybrid ORC binary plant (Configuration 2), 62 kWe for a hybrid compound flash-binary plant (Configuration 3), and 368 kWe for a hybrid geothermal-preheat plant (Configuration 4). Of these configurations, all had a higher utilization efficiency compared to Benchmark A, with all but Configuration 3 having a higher utilization efficiency than Benchmark B.

When Configuration 4 is compared to a standalone bioenergy thermal plant (Benchmark C) of equal nameplate capacity, there is a drop of one percent in utilization efficiency and a 26% reduction of feedstock required. The latter translated to 0.021 kg/s of carbon negative emissions and 0.051 kg/s of carbon neutral emissions for Configuration 4, relative to 0.097 kg/s of carbon neutral emissions for Benchmark C. 100% of biogenic CO₂ emissions could be captured for Configurations 1, 2 and 3. Only 30% was captured in Configuration 4 because of the limited CO₂ carrying capacity of reinjected brine. Despite this, Configuration 4 had the highest gross annual sequestration when converting 0.021 kg/s to 675 tonnes per year.

This study demonstrated that geothermal-BECCS configurations are thermodynamically feasible and can be theoretically used to offset emissions between -209 gCO₂e/kWh and -922 gCO₂e/kWh. We showed that these designs could achieve nominal sequestration scales of 1 MtCO₂ per year when scaled in relation to plausible geothermal plant sizes (e.g., 124 MWe for Configuration 3).

In practice, the proximity of the geothermal system to the biomass feedstock will be a limiting factor in the overall feasibility of geothermal-BECCS systems. The effects of dissolved minerals have been considered and are manageable. Importantly, further analysis of electricity, feedstock and CO₂ sequestration market conditions is required to determine the economic feasibility of site-specific geothermal-BECCS systems.

Geothermal-BECCS systems could improve the accessibility of most of the world's geothermal systems, which are classified as low temperature. This is achieved through improved plant utilization efficiency with the spill-over benefit of de-risking low-enthalpy well encounters during exploration. Furthermore, as a negative emissions technology, it is compatible with policy environments that tax emissions or enable offsetting. Finally, with so many advantages, geothermal-BECCS could provide a pathway to fulfil the uptake in BECCS technologies required for global climate change mitigation.

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8. Appendix A

Table A.1: Working fluid cycle for Benchmark B

		Pressur e		Enthalpy
		P (Bar)	h (kJ/kg)	
Turbine Inlet	1	18.00	733.0	Vapor saturation at Evaporator
Turbine Exhaust	2	1.87	657.5	Dry expansion
Condensed Vapor	3	1.87	578.2	State at condenser pressure
Condensed Liquid	4	1.87	249.5	State at condenser pressure
Pump Exit	5	18.00	253.1	Compressed delivery
Preheater	6	18.00	524.8	Heated to liquid saturation

Table A.2: Working fluid cycle for Benchmark C

		Pressur e		Enthalpy
		P (Bar)	h (kJ/kg)	
Turbine Inlet	1	18	3470.3	Superheating
Turbine Exhaust	2	0.09	2524.7	Significantly dry expansion
Condensed Vapor	3	0.09	2580.3	Frame of reference
Condensed Liquid	4	0.09	183.3	State at condenser pressure
Pump exit	5	18	185.7	Compressed delivery
HE1 Exit	6	18	884.6	Preheating

914

Table A.3: Working fluid cycle for Configuration 2

		Pressure		Enthalpy
		e		
		P (Bar)	h (kJ/kg)	
Turbine Inlet	1	18.00	733.0	Evaporator heated by biomass
Turbine Exhaust	2	1.87	657.5	Dry expansion
Condensed Vapor	3	1.87	578.2	State at condenser pressure
Condensed Liquid	4	1.87	249.5	State at condenser pressure
Pump Exit	5	18.00	253.1	Compressed delivery
Preheater	6	18.00	524.8	Preheater heated by geofluid

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Table A.4: Working fluid cycle for binary portion of Configuration 3

		Pressure		Enthalpy
		P (Bar)		h (kJ/kg)
Turbine Inlet	1	2.35	590.2	Vapor saturation at Evaporator
Turbine Exhaust	2	1.87	583.5	Dry expansion
Condensed Vapor	3	1.87	578.2	State at condenser pressure
Condensed Liquid	4	1.87	249.5	State at condenser pressure
Pump Exit	5	2.35	249.6	Compressed delivery
Preheater	6	2.35	268.1	Heated to liquid saturation

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Table A.5: Working fluid cycle for Configuration 4

		Pressur	Enthalpy	
		e		
		P (Bar)	h (kJ/kg)	
Turbine Inlet	1	18	3470.3	Biomass superheating
Turbine Exhaust	2	0.09	2524.7	Significantly dry expansion
Condensed Vapor	3	0.09	2580.3	Frame of reference
Condensed Liquid	4	0.09	183.3	State at condenser pressure
Pump exit	5	18	185.7	Compressed delivery
HE1 Exit	6	18	884.6	Geofluid preheating

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923 **9. Appendix B – CO₂ compression parasitic load**

924 For each geothermal-BECCS configuration the CO₂ will need to be compressed to dissolution
 925 conditions. This work to compress the CO₂ will incur a parasitic load that must be accounted for when
 926 opting for sequestration through in-line dissolution. A demonstration of this calculation is provided
 927 here for Configuration 4. The change in pressure across the compressor (ΔP_C) is calculated as follows
 928 in Equation B1:

$$\Delta P_C = P_{dis} + P_{wh} - P_{ex} - \rho_{CO_2} g Z_{dis} \quad (B1)$$

929 P_{dis} is the dissolution pressure at the sparger (50 bar, 5×10^6 Pa), P_{wh} is the wellhead injection pressure
 930 (assumed to be 10 bar, 10^6 Pa), P_{ex} is the exit pressure of the CO₂ from the boiler (assumed to be 1 bar, 10^5
 931 Pa), ρ_{CO_2} is the density of the CO₂ at the sparger found through equations of state (~ 45 kg/m³ at 50 bar
 932 and 95°C), g is the acceleration due to gravity (9.81 m/s²) and Z_{dis} is the sparger depth (400 m). Thus, ΔP_C
 933 is approximately 5.7 MPa. The specific compressor work (w_C) is found with the following equation (Silla,
 934 2003):

$$w_c = \left(\frac{k}{k-1} \right) R T_{CO_2} \left[\left(\frac{P_c}{P_{ex}} \right)^{\frac{k-1}{k}} - 1 \right] \quad (B2)$$

Where k is a ratio of the specific heat of CO₂ at a constant pressure to the specific heat of CO₂ at a constant volume, R is the individual gas constant (J/kgK) and T_{CO_2} is the temperature of the CO₂ in Kelvin. These were assumed to be 1.28, 188.92 J/kgK and 313.15 K respectively. w_c is approximately 385 kWe/kg. To find the total work done by the compressor (W_c), the specific work is multiplied by the mass rate of sequester able CO₂ ($\dot{m}_{CO_2}$), which was 0.021 kg/s for Configuration 4. Thus, W_c is 8.1 kWe, a parasitic load of roughly 2.2% of the 368 kWe generated by the geothermal-BECCS configuration.

10. Appendix C – Surface pump parasitic load

The work of surface pumps to compress working fluid from the condenser pressure to the preheater pressure is an important parasitic load in Rankine cycle plants. A demonstration of this calculation is provided here for Configuration 4. Working fluid leaves the condenser at the saturated liquid condition at the pressure of the condenser (0.09 bar). Its enthalpy (h_{Cond}) is found using the equations of state of water (183.26 kJ/kg). The same is done for the specific volume (v_{Cond}), 0.001 m³/kg, to find the isentropic enthalpy of the working fluid at the pump exit ($h_{p,isen}$).

$$h_{p,isen} = h_{Cond} + v_{Cond}(P_{ph} - P_{Cond}) \quad (C1)$$

Where P_{ph} is the pressure of the preheater (1.8 million pascals) and P_{Cond} is the pressure of the condenser (0.009 million pascals). The value for $h_{p,isen}$ is approximately 185.07 kJ/kg. The true pump exit enthalpy of the working fluid can now be found using the efficiency of the pump (η_p), assumed to be 75%.

$$h_{p,ex} = h_{Cond} + \frac{h_{p,isen} - h_{Cond}}{\eta_p} \quad (C2)$$

The value for $h_{p,ex}$ is thus calculated to be 185.67 kJ/kg. The working fluid mass ($\dot{m}_{wf}$) is 0.39 kg/s.

The work of the pump is thus 0.94 kWe, according to the following equation (DiPippo, 2016):

$$W_p = \dot{m}_{wf}(h_{p,ex} - h_{Cond}) \quad (C3)$$