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Bioenergy-Boosting: Improving the Energy, Economic, and Emissions Profile of Marginal Geothermal Resources

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ABSTRACT

Globally, the first 10 000 MW of geothermal generation was able to take advantage of pristine, high-temperature resources at relatively shallow depths. For the next 10 000 MW and beyond, we will need to find new ways to improve generation economics in lower-temperature, marginal systems. Hybridizing geothermal generation with bioenergy is one approach for topping up resource enthalpy while also adding new revenue streams that increase project cash flow and shorten capital payback.

In this paper, we present order-of-magnitude calculations of the energy, economic, and emissions benefits that may be realized through bioenergy hybridization. Our analysis is centered on a generic flash plant and considers the incremental performance gained from a unit of biomass combustion. We use a thermodynamic-financial-carbon model of the total power cycle to quantify the additional mass or enthalpy of produced steam as well as the production rate of green CO_2. We then calculate revenue from net electricity generation and carbon removal sales of green CO_2, and compare these against globally-sourced CAPEX and OPEX rates.

We find that incorporating bioenergy-boosting into a geothermal energy cycle is mainly favorable for lower-temperature, marginal geothermal resources. A plant design that includes biomass heating of produced geofluid prior to separation produces a larger steam fraction for turbine dispatch, and this was found to be more effective than a hybrid that uses direct heating of the separated steam. Both biomass and carbon removal pricing are key factors in project cost, but we find that bioenergy hybrids are likely to outperform standard geothermal plants under reasonable price ranges (<140 USD/tBio and >50 USD/tCO_2). Importantly, by offsetting project costs with new green revenues, we predict that total reserves of developable geothermal could be substantially increased. This is because systems that would otherwise be classified as marginal or uneconomic under other plant designs, have lower costs under hybrid schemes. Finally, geothermal-bioenergy hybrids with CO_2 removal have high rates of negative emissions at low to medium temperatures, exceeding -1000 gCO_2/kWh, which helps contribute to climate goals beyond decarbonizing the electricity system.

1. INTRODUCTION

Geothermal electricity and direct heat are poised to play a key role in global decarbonization. The previous decade has seen increased interest in new technologies, with installed capacity increasing by 30% between 2015 and 2020 (Huttrer, 2021). However, historic developments have targeted fields with shallow, high-temperature (>200°C) reservoirs that have comparatively low development costs. These systems frequently occur in the volcanic regions of a small club of geologically fortunate countries. If future geothermal opportunities are to be shared globally, then the community needs to find lower cost ways to make use of marginal systems, which are likely to comprise the largest proportion of available resource, e.g., Hochstein (1990) estimates 95% of all systems have a temperature lower than 225°C.

The two physical quantities that characterize a good geothermal resource are high temperature and high permeability (with benign fluid chemistry also important). These factors contribute to the geofluid being easier to extract and, given its higher enthalpy, result in a larger fraction of separated steam. At lower values of temperature and permeability, more wells are needed to meet a given plant size, which leads to higher overall costs. Thus, reservoir temperature and average well productivity (derived from permeability) are two proxy measures that can be used to estimate whether a resource is likely to be economic or marginal.

One way to improve the economics of marginal resources is to develop additional revenue streams that complement the sale of heat or power. These could include coproduction of hydrogen (e.g., Mokai power plant; Thomas et al., 2020), extraction of lithium from geothermal brines (e.g., Sajkowski et al., 2023), separation and sale of CO_2 for food or horticultural applications, or injection of biogenic CO_2 as a carbon removal offset (Titus et al., 2023a).

Complimentary revenue streams can arise when hybridizing geothermal with a second biomass-based energy source. Hybrid fuel cycles are attractive from a geothermal perspective since increasing the temperature of extracted geofluid can increase overall power generation efficiency. Hybrids with solar (Matente et al., 2011; Greenhut et al., 2010), fossil fuel (Kestin et al., 1978), and bioenergy (Thain and DiPippo, 2015; Dal Porto et al., 2016) have been explored. However, they are not without their own drawbacks, suffering either from intermittency (solar), incurring fuel costs (fossil fuel and bioenergy), or by increased emissions (fossil fuel).

A geothermal-bioenergy hybrid has been demonstrated at the Cornia-2 geothermal flash plant in Lardarello, Italy. At this plant, geothermal steam was superheated from 150°C to 375°C prior to turbine entry (Dal Porto et al., 2016), yielding a further 6 MWe of power. The hybridization was a retrofit operation to address plant underperformance, involving insertion of a biomass boiler and heat exchanger directly in the steam line between the separator and the turbine. In contrast, at a binary plant, geothermal fluid can be heated by biomass waste heat (Briola et al., 2019) before the organic Rankine cycle (ORC) or a bioenergy heat exchanger can be installed after the conventional vaporizer and preheater to superheat the working fluid (Toselli et al., 2019). Hybrid geothermal-bioenergy designs have been investigated for the Wairakei geothermal system (Chester, 2016), however, their economics can be challenging, particularly when biomass and boiler CAPEX costs are high.

To improve economic performance, there are certain complimentary revenue streams that could be leveraged from geothermal-bioenergy hybrids (Fig. 1). This power cycle also involves production of green (biogenic) CO_2 from combusted biomass, which is ultimately derived from an atmospheric source. Appropriately purified, CO_2 can be used in food processing, water treatment, and in greenhouses, thereby displacing fossil sources of CO_2. The CO_2 could also be injected back into the geothermal reservoir to create saleable negative emissions (Titus et al., 2022). Alternatively, the biomass could be used as input to a high-temperature pyrolysis or gasification process that also drives off volatiles (H_2, CO, CO_2, N_2) with various value for industrial chemical manufacture or additional heating in the geothermal power cycle.

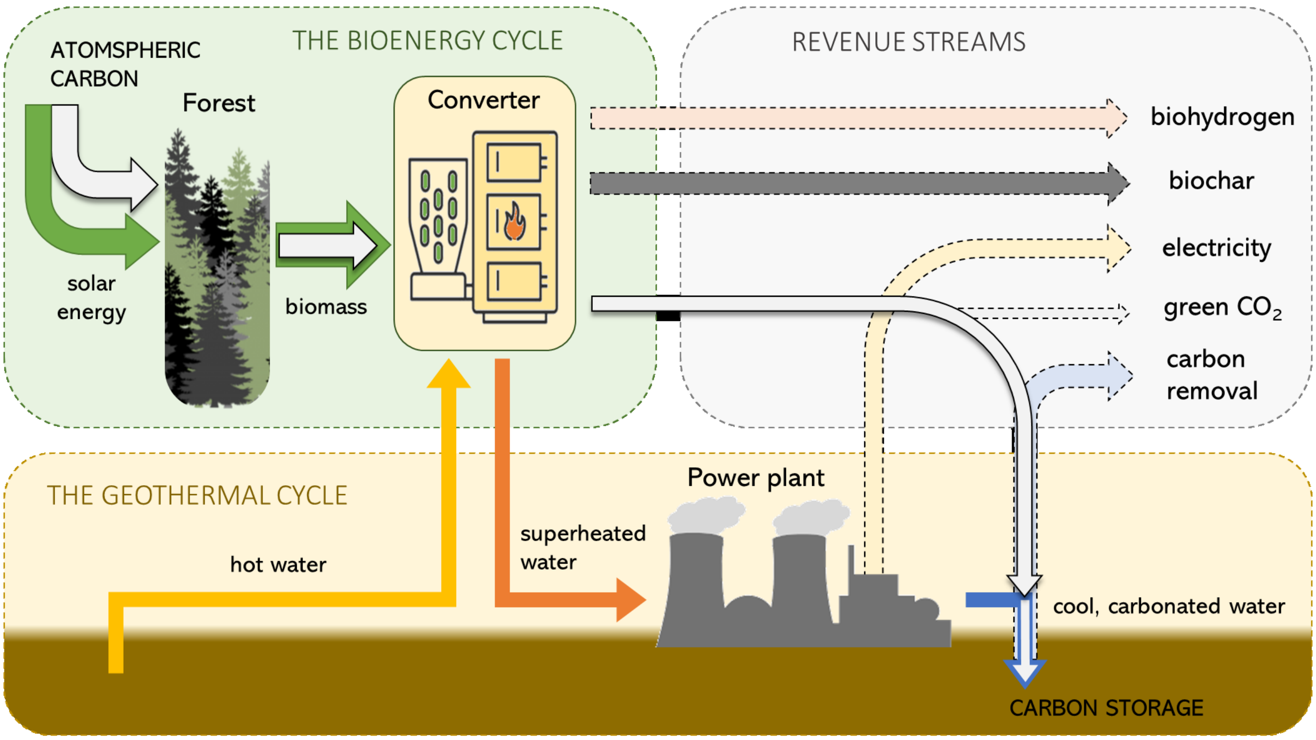

Figure 1: Possible revenue streams arising from a geothermal-bioenergy hybrid plant. Arrows are schematic and denote the passage of key mass elements: water (yellow, orange, blue for different temperatures), biomass (green-white) and CO_2 (white). Possible revenue streams are denoted by dashed arrows anchored at their originating component in the energy cycle.

The purpose of this study is to quantify how additional revenue streams can be leveraged to improve the economic characteristics of marginal geothermal resources. To do this, we model the economics of geothermal-bioenergy hybrids with CO_2 removal under various plant design and revenue parameters. We then quantify by how much a marginal resource is pushed towards economic feasibility when a hybrid plant design is considered.

Marginal systems are defined here as those whose temperature or well productivity is at or just below the threshold to be considered economic. For simplicity, we have defined these thresholds in terms of the levelized cost of electricity (LCOE), which is a single bulk description of the costs of producing electricity. However, we recognize that this is an incomplete description of marginality, and that myriad other factors must be considered when developing a project, including reservoir chemistry, and local market, environmental or political factors. Here, we have taken a narrow focus on the thermodynamic considerations that impact the cost of generating electricity.

2. MODELLING METHODOLOGY

This study follows the methodology of Titus et al. (2022, 2023a, 2023b, 2023c) and Dempsey et al. (2023) in evaluating the performance of hybrid geothermal-bioenergy-carbon removing power cycles. Prior work has introduced models to analyze the thermodynamics of flash and binary hybrids (Titus et al., 2023a), the carbon removal economics of new build (Titus et al., 2022) and retrofit designs (Titus et al., 2023b; Titus et al., 2023c), and their potential scalability in major geothermal nations (Dempsey et al., 2023).

Here, our analysis is restricted to a single-flash plant with condensing turbine design as a benchmark, and two bioenergy hybrid designs (Fig. 2). The first involves biomass heating of the separated steam phase to a specified temperature. The second involves biomass heating of the produced geofluid prior to separation resulting in a larger fraction of separated steam. All configurations reinject 100% of the separated brine with hybrid designs using this water for dissolution and disposal of green CO_2 captured from biomass combustion. The sections below recount key model calculations from prior work and the reader is referred to the references for further details.

2.1 Thermodynamic calculations

2.1.1. Base geothermal plant (single-flash)

Two-phase geofluid is sourced from a reservoir at temperature T_{res} (°C) and specific enthalpy h_{res} (kJ/kg). The geofluid is produced adiabatically at mass rate $\dot{m}_{res}$ (kg/s) using N wells each with average productivity Γ (kg/s). Produced fluid is dispatched to a separator where it is separated into steam and brine components (Fig. 2A). The separation temperature, T_{sep}, is determined by the optimal separator temperature as the average of the condenser and reservoir temperatures. Separated steam at rate $\dot{m}_s$ is sent to a condensing turbine. Power generation is calculated from the product of steam mass rate and difference in enthalpy between inlet, h_s (kJ/kg) and real turbine exhaust of the steam condensate, h_{ex} (kJ/kg)

$$W_g = \dot{m}_s(h_s - h_{ex}). \tag{1}$$

Exhaust enthalpy is found by incorporating the isentropic turbine exhaust enthalpy of steam condensate and the dry turbine efficiency (85%) into the dry expansion equation (Janes, 1984). The plant is scaled to a reference output (100 MWe) by choosing an appropriate number of wells, N.

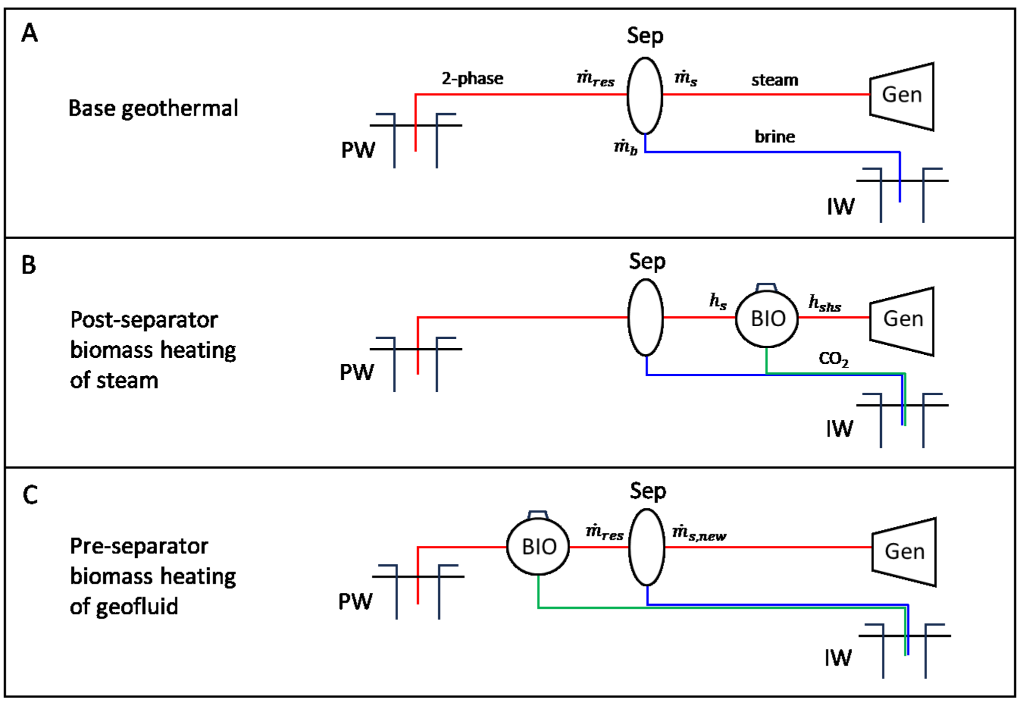

Figure 2: Schematic plant configurations considered here. (A) 2-phase fluid is sourced and combined from the production wells (PW) and split into brine (blue) and steam fractions (red) at the separator (Sep). The steam phase is dispatched to the generation assembly (Gen: turbine, condenser, condensate injection) while brine is dispatched to the injection wells (IW). (B) The first hybrid configuration includes a biomass boiler (BIO) on the steam line to boost steam enthalpy from h_s to h_{shs}. (C) The second hybrid configuration includes a biomass boiler on the 2-phase line to increase the enthalpy of geofluid entering the separator. This boosts steam mass fraction from $\dot{m}_s$ to $\dot{m}_{s,new}$. CO_2 from biomass combustion (green) is directed for brine dissolution.

2.1.2. Steam heating hybrid

This configuration modifies the base geothermal plant by adding biomass heating of the separated steam (Fig. 2B), increasing T_{sep} to the higher temperature T_{shs}. This steam is dispatched to the same condensing turbine with power generation now calculated by substituting h_{shs} for h_s in Eq. (1). Heating of the steam occurs in a biomass boiler. The required heat from the boiler $\dot{Q}_{bio}$ (MW) is dependent on the mass flow rate of steam and the required enthalpy increase

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

To achieve this level of superheating, biomass is combusted at a mass rate $\dot{m}_{bio}$ releasing an amount of energy determined by the higher heating value of the biomass feedstock (HHV) and the efficiency of the biomass boiler (η_{boiler}=80%). The biomass fuel is assumed to be forestry residues with an HHV of 16 MJ/kg.

The biomass burn rate is

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

Biomass combustion occurs in a high oxygen environment to maximize fuel consumption and CO_2 output. Parasitic loads from air separation are deducted from saleable power. CO_2 is generated from combustion at a mass rate proportional to fuel consumption and emissivity of the fuel-combustion cycle (X=1.6 tCO_2/tBio)

$$\dot{m}_{CO2} = \dot{m}_{bio} X. \tag{4}$$

2.1.3. Geofluid heating hybrid

This configuration modifies the base geothermal plant by adding biomass heating of the produced geofluid prior to its separation (Fig. 2C). Separation temperature is not changed from the base geothermal configuration. The geofluid is heated from h_{res} to the higher enthalpy h_{new}, where h_{new} is determined so as to achieve a fixed increase, X_s, of the separated steam mass fraction to $\dot{m}_{s,new}$

$$\dot{m}_{s,new} = \dot{m}_{res}\left(\frac{\dot{m}_s}{\dot{m}_{res}} + X_s\right). \tag{5}$$

The geofluid enthalpy corresponding to this mass fraction is

$$h_{new} = \frac{\dot{m}_{s,new}}{\dot{m}_{res}}\left(h_v(P_{sep}) - h_l(P_{sep})\right) + h_l(P_{sep}). \tag{3}$$

where h_l and h_v are the liquid and vapor enthalpies at the separator pressure P_{sep}. The required heat from the biomass boiler depends on the mass flow rate of produced geofluid and the required enthalpy increase

$$\dot{Q}_{bio} = \dot{m}_{res}(h_{new} - h_{res}). \tag{6}$$

Biomass input and CO_2 output calculations are the same as Section 2.1.2.

2.1.4. Carbon dioxide injection

Separated brine at mass rate, $\dot{m}_b$, is dispatched to reinjection wells. Post-combustion captured CO_2 is dissolved in the reinjected brine at depth using a bubbler. The solubility of CO_2 in water is calculated from Duan and Sun (2003) using the reinjection temperature (95°C) and in-well hydrostatic pressure (up to 5 MPa for a 500 m deep bubbler). Any CO_2 beyond the maximum dissolution capacity is vented and not included in carbon removal calculations, although the foregone revenue can be quantified as an opportunity cost. Parasitic loads to compress CO_2 are deducted from saleable power, with calculation given in Titus et al. (2023c).

2.2 Economic calculations

The major costs of the above plant designs are calculated as net present values (NPV) assuming a 30-year project life, an 8% discount rate and 20% contingency. Costs are divided into capital (CAPEX), operating (OPEX) and biomass fuel. Costs are offset by the net present value of revenues from carbon removal.

Capital cost of the geothermal plant is divided into the costs of drilling and completing wells, and any other capital (generator, steam field, etc.). IRENA (2021) quotes a flat capital cost rate Z_{geo} for geothermal plants of 3991 USD/kWe, which does not directly account for the numbers of wells in the plant. Here, we have used 25% of the IRENA capital cost rate to estimate non-well components of the capital, and a separate rate Z_{well} (10 million USD/well) to cost the remaining well component.

Capital costs for biomass boilers are estimated using the flat rate Z_{bio}=2353 USD/kW from IRENA (2021).

$$C_{CAPEX} = \frac{1}{4} Z_{geo} W_g + Z_{well} N_{well} + Z_{bio} Q_{bio}. \tag{7}$$

Capital costs for air separation and CO_2 compression are calculated on a per power basis and included in the total. Annual operating costs include a fixed rate for geothermal (115 USD/kWe/year), and CAPEX percentages for bioenergy (6%) and carbon removal (3%).

The costs of biomass fuel are calculated assuming a fixed rate of 88 USD per tonne of biomass. This is a key economic parameter whose sensitivity is considered later. Annual carbon dioxide removal (CDR) is assumed to be saleable at a fixed rate of 100 USD per tonne of CO_2, and the sensitivity of this parameter is also discussed later.

Finally, the levelized cost of electricity generation is calculated as the NPV of all costs less the NPV of all revenues other than electricity generation (in this case, from CDR). These costs are divided by the NPV of net electricity generation.

$$LCOE = \frac{NPV_{COSTS} - NPV_{CDR}}{NPV_{electricity}}. \quad (8)$$

Note that although revenues from CDR are presumed to be positive, for geothermal systems with high natural emissions and an emissions pricing framework, the term NPV_{CDR} could switch sign and become another cost of the development.

3. RESULTS

The sections below discuss the major trends and sensitivities of these technoeconomic models. The study is not an exhaustive examination of all possible parameter ranges, which arguably will vary with national context. Instead, we have used average quantities that approximate the center of the global range, where known, and indicative values elsewhere. Studies tailored to individual sites may arrive at different predictions of power production or costs. However, we argue that key trends and concepts relating to the performance of geothermal-bioenergy hybrids are likely to be valid over a range of conditions.

3.1 Performance of base geothermal plant

We begin with a description of the modeled behavior of the base geothermal plant as this provides a benchmark against which to compare hybrid plants. Several thermodynamic and economic performance indicators have been investigated across two key properties of geothermal reservoirs: temperature and productivity. It is these two properties that, to first order, determine whether a system is economic or marginal.

As would be expected, a single flash geothermal plant incurs lower costs to produce electricity (Fig. 3C) from reservoirs with higher temperatures. This is mainly because the higher reservoir enthalpy results in a larger separated steam fraction (Fig. 3B), and this in turn means fewer wells need to be drilled (Fig. 3A) to achieve a fixed plant size. For example, using this model, a 100 MWe plant can be developed with 21 production wells in a 250°C reservoir, with LCOE of 61 USD/MWh. In 2021, the global weighted average LCOE was 68 USD/MWh, so this would (on paper) appear an economic reservoir for development. By comparison, a 200°C reservoir requires 37 wells to deliver the required steam, at a higher LCOE of 85 USD/MWh. This is 25% higher than the 2021 average and thus, arguably, a marginal system for development.

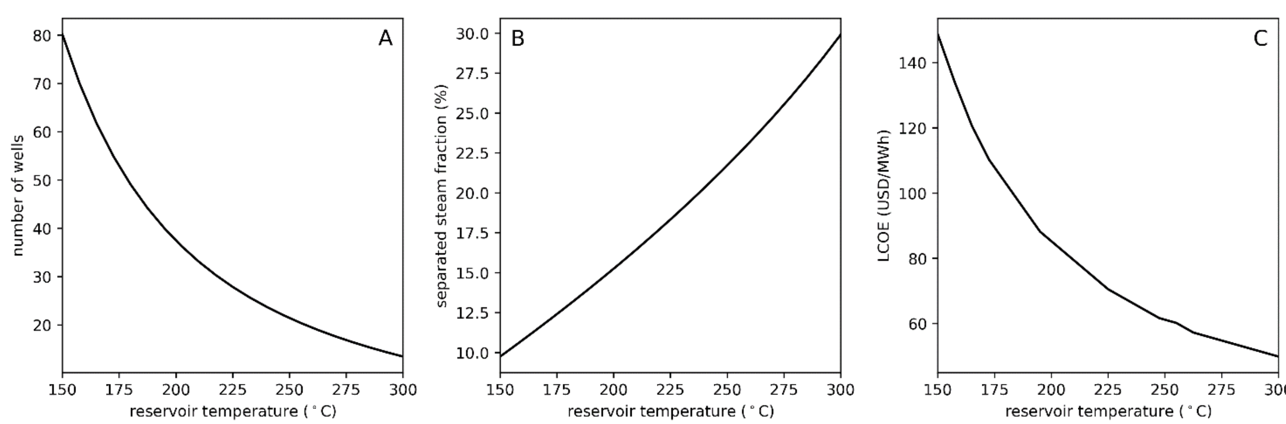

Figure 3: Thermodynamic and economic characteristics of a modeled conventional (base) single-flash geothermal plant as a function of reservoir temperature. (A) Number of wells needed to reach 100 MWe plant size. A lower temperature resource requires more wells to make up the required mass of steam. (B) Mass fraction of separated steam increases with resource temperature. (C) Levelized cost of electricity (LCOE) declines with increasing resource temperature, which is mainly driven by the fewer number of required wells.

As also was expected, a single flash geothermal plant incurs lower costs to produce electricity from reservoirs whose wells have higher average productivity (Fig. 4). This is because as well productivity increases, fewer total wells are needed to achieve the fixed plant size (Fig. 4A). For example, using this model, a 100 MWe plant can be developed above a 230°C reservoir using 26 production wells that each deliver 50 kg/s. For this configuration, the LCOE is 69 USD/MWh, approximately the 2021 global weighted average, i.e., likely to be economic. By comparison, if the same temperature reservoir had a lower average productivity of 30 kg/s/well, then 44 wells would be needed to meet plant capacity. The corresponding LCOE is 95 USD/MWh and, thus, this represents a more marginal system from a development perspective.

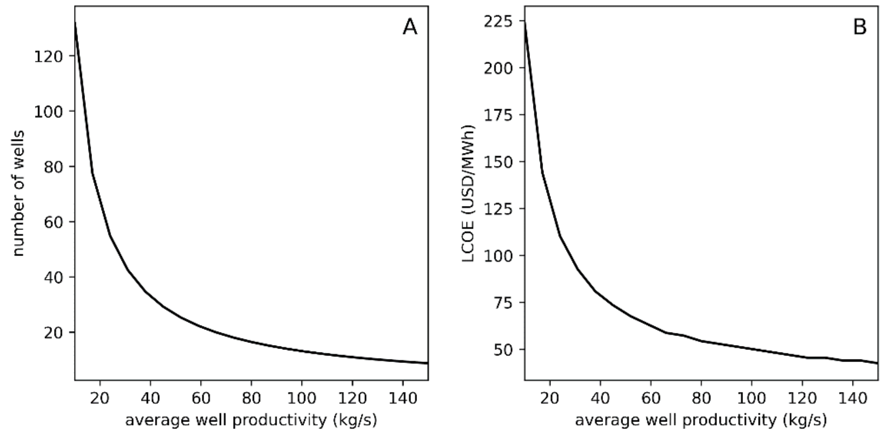

Figure 4: Economic characteristics of modeled unhybridized (base) single-flash geothermal plant as a function of reservoir productivity, approximated here by average well productivity. (A) Number of wells needed to reach 100 MWe plant size. As average well productivity increases, fewer wells are needed to make up the required mass of steam. (B) Levelized cost of electricity (LCOE) declines with increasing well productivity, which is mainly driven by the fewer number of required wells.

3.2 Performance of biomass heating hybrids

The first hybrid type uses biomass to heat separated geothermal steam to a temperature of 300°C before dispatching it to the turbine. Post-combustion CO_2 from the biomass is captured, dissolved in the separated brine, and injected into the geothermal system. For the same reservoir temperature and productivity, this plant design requires fewer wells than the base geothermal plant (Fig. 5A), e.g., 18 vs. 21 wells for a 250°C reservoir; 31 vs. 37 wells for a 200°C reservoir. Fewer wells are needed because biomass combustion contributes energy to the total plant generation. Generation costs are also lower, with LCOE 16% lower on average than the base geothermal plant (Fig. 5B). This is due both to the reduced CAPEX spend on wells, as well as new revenues from carbon dioxide removal. These savings more than offset the new costs of bioenergy. For the 200°C reservoir, LCOE is 69 USD/kWh which moves this resource into a "likely economic" classification compared to its "marginal" status if developed with the base geothermal plant (85 USD/kWh).

The second hybrid type uses biomass to heat the produced fluid so that, after separation, the steam mass fraction is five percentage points higher. Post-combustion CO_2 is again captured and reinjected. For the same reservoir temperature and productivity, this plant design uses about the same number of wells as the steam-heating hybrid. However, the generation costs are lower than the first hybrid, and on average 31% lower than the base geothermal plant (Fig. 5B). In this case, the difference is mainly due to a larger biomass burn rate to heat the geofluid and hence a greater amount of green CO_2 available for removal and CDR revenues. For the 200°C reservoir, the LCOE is 55 USD/kWh, well below the 2021 global weighted average, and much lower than the marginal 85 USD/kWh of the base geothermal plant.

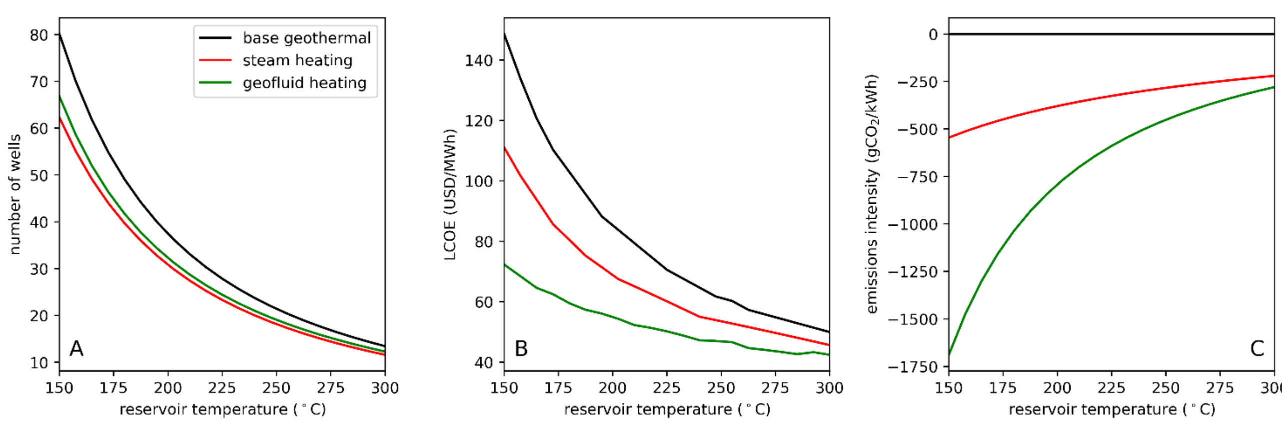

Figure 5: Comparison of thermodynamic and economic characteristics of base (black) and two hybrid bioenergy plant designs: direct heating of separated steam to 300°C (red); and heating of produced fluid prior to separation to increase steam mass fraction by 5% (green). (A) Number of wells needed to reach 100 MWe plant size. Both hybrid plants achieve the same power output with fewer wells. (B) Levelized cost of electricity (LCOE) is lower across all modelled temperatures for both hybrid plants, which is mainly driven by negative emissions revenues (injection of green CO_2 into the geothermal system). (C) Emissions intensity, which is negative for all hybrid systems due to injection of green CO_2. Magmatic and life-cycle emissions have not been considered.

A desirable feature of these geothermal-bioenergy hybrids is their negative emissions profile. Emissions intensity quantifies the CO_2 released or sequestered in the production of one unit of energy (Fig. 5C). Bertani and Thain (2002) calculated a global MW-weighted average emissions intensity for geothermal of 122 gCO_2/kWh with a wide range of individual values, 4–740 gCO_2/kWh. These estimates are for fuel cycle emissions only and do not consider the full lifecycle of a geothermal plant, including construction and decommissioning (McLean and Richardson, 2021). Some geothermal plants in Türkiye produce fluids from carbonate reservoirs and these can have particularly high emissions intensities exceeding 1000 gCO_2/kWh (Fridriksson et al., 2017), which is on par with coal generation. For simplicity, emissions from the base geothermal plant have been ignored in most models shown here.

In comparison, negative emissions from the hybrid plants range from -250 to higher than -1700 gCO_2/kWh (Fig. 5C). Steam heating hybrids consume comparatively less biomass and hence have lower negative emissions. This plant design may be insufficient to offset the positive emissions from particularly gassy geothermal fields. Negative emissions from geofluid heating hybrids are much larger, particularly at lower temperatures where bioenergy makes up a greater proportion of the plant size and where there is a much larger brine fraction in which to dissolve CO_2.

3.3 Sensitivity analysis

Although bioenergy hybridization can lead to lower cost than base geothermal, increasing the amount of biomass heating does not always lead to further cost reductions. For example, increasing the temperature of heated steam in the first hybrid type from 250 to 350°C results in only incremental reductions of LCOE (Fig. 6A). For the geofluid heating hybrid, heating to increase the steam fraction a further 10 percentage points results in higher costs compared to a plant that only increases steam five points. This is because the higher bioenergy load produces so much CO_2 that a large fraction cannot be dissolved in the brine and must be vented to the atmosphere. The foregone CDR revenues were important for offsetting the high cost of biomass fuel, and hence the LCOE ends up larger. Finding other uses for this green CO_2, either by dispatching it to another storage site for CDR revenue, or selling it for domestic consumption, could recover these costs and make high steam fraction designs economic. Care must also be taken with geofluid heating so that dissolved species are not overconcentrated in the separated brine, leading to scaling problems. This may be partially offset by the dissolution of CO_2 into the brine, which would lower its pH and inhibit or slow some scaling reactions.

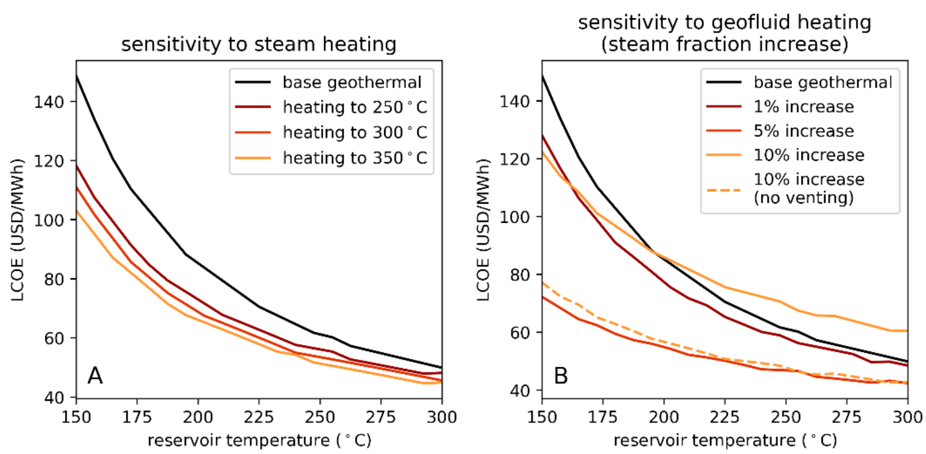

Figure 6: Sensitivity of electricity costs to design parameters of hybrid plants. (A) Heating of separated steam to higher temperatures leads to incremental reduction of electricity generation costs. (B) Additional heating to achieve higher steam fractions sometimes leads to costs reductions, e.g., from +1% to +5%. At higher steam fractions, e.g., +10%, not all green CO_2 produced during heating can be captured in the reinjection and must be vented. This opportunity cost leads to higher overall generation costs (cf. dashed and solid lines at +10% steam, which quantify this lost revenue).

The economics of geothermal-bioenergy hybrids are also dependent on cost parameters. Biomass fuel cost is a key determinant of overall project cost (Fig. 7A & E), and prices higher than about 140 USD/tBio are enough to offset any revenues realized from CDR. Biomass fuel types vary widely in their embodied cost (sourcing, transportation, storage) and thermodynamic parameters (higher heating value, CO_2 release fraction). In New Zealand, forestry residues are estimated to be available at an upper price limit of 90 USD/tBio

CDR revenue is the major complimentary revenue stream that drives the LCOE of hybrid systems below base geothermal. At a carbon removal price of 50/tCO_2, CDR revenue is approximately balanced by new bioenergy costs, and hence hybrids have similar LCOE to base geothermal (Fig. 7B & E). Higher CDR prices push project LCOE lower, or negative for geofluid heating hybrids at low-temperature.

An emissions pricing market that rewards carbon removal should arguably also price operational emissions from geothermal. For clarity of presentation, this has been excluded from most of our models. However, Fig. 7C & F shows the effect of charging operators for CO_2 emissions at the global average of 122 gCO_2/kWh. When these costs are included, the cost gap between non-hybrid and hybrid systems grows large with increasing carbon removal price (Fig. 7C). This is because the LCOE of a base geothermal plant increases as its positive emissions are priced, while the LCOE of the net negative hybrid plant decreases with larger revenues from negative emissions.

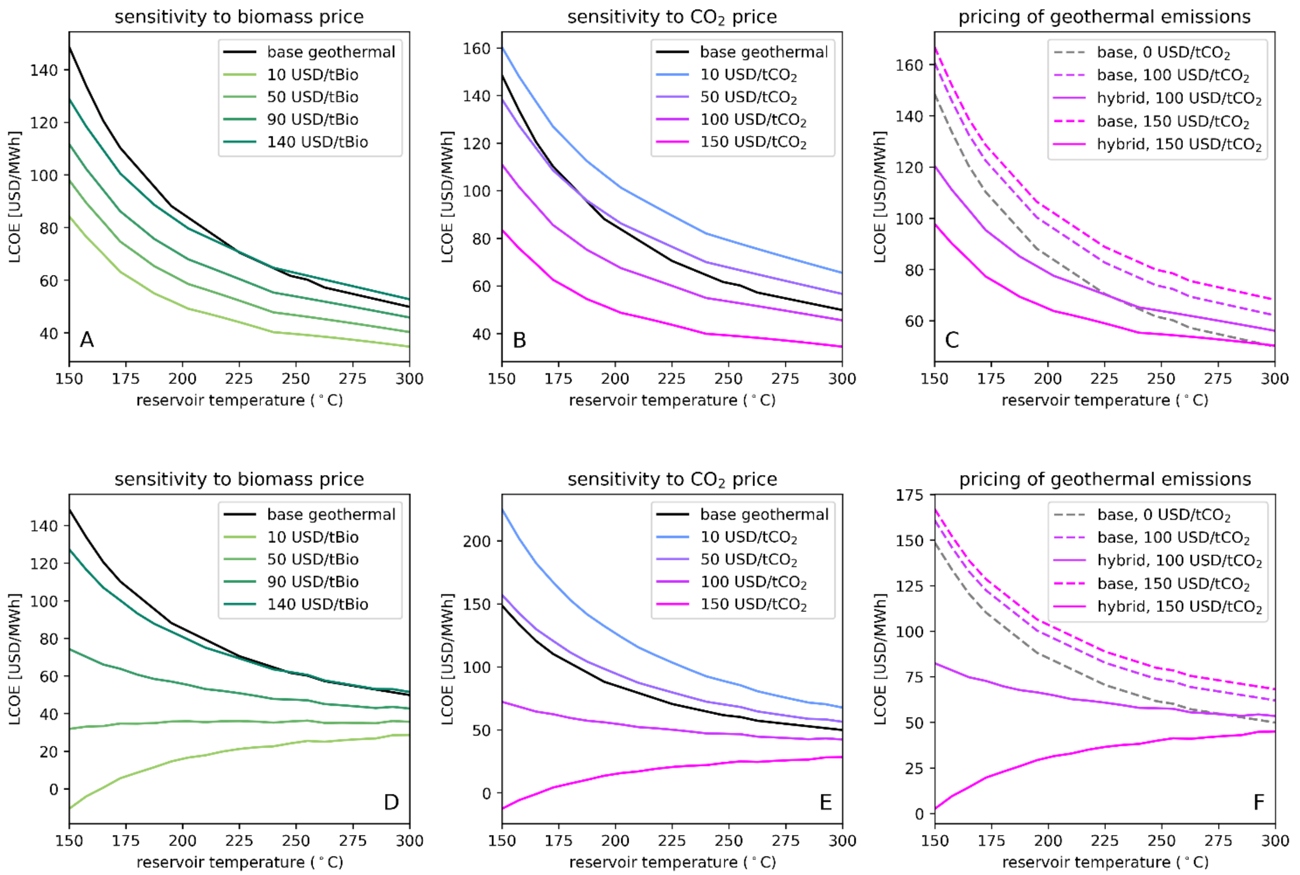

Figure 7: Sensitivity of electricity costs to price parameters for a 100 MWe hybrid system that (A-C) heats steam to 300°C and (D-F) heats geofluid for an additional +5% steam fraction. (A & D) Higher biomass prices are passed on as higher generation costs. (B & E) Higher carbon removal prices lead to lower overall generation costs. At a carbon price of 50 USD/tCO_2, additional costs of hybridizing are approximately offset so that hybrid and base plants have similar LCOE. (C & F) Effect of pricing operational geothermal emissions for a base plant with emissions intensity at the global average (122 gCO_2/kWh). Base geothermal plants become more expensive at higher CO_2 prices while the cost difference between hybrid and conventional plants becomes larger.

3.4 Shifting boundaries between marginal and economic resources

One way to think about hybridization, or any new geothermal technology, is how it affects the boundary separating resources that are likely to be economic from those deemed to be marginal. For the sake of illustration, we have set this threshold at an LCOE of 60 USD/MWh, however, in practice marginality will depend on local market context and other non-cost factors. Nevertheless, Figs. 8A and 9A show how the threshold LCOE is met at different values of resource temperature and productivity, depending on which technology is deployed. For instance, developed with a base geothermal plant, only systems with temperatures higher than 256°C are likely to be economic. In comparison, steam heating and geofluid heating hybrids exceed the economic threshold at lower temperatures, 225 and 179°C, respectively. Cost breakdowns show that although the cooler reservoirs require more wells, this is adequately offset by complimentary CDR revenues (Fig. 8B).

There is a similar relationship with resource productivity. For a 230°C reservoir, wells must produce on average 64 kg/s to meet the economic threshold for base geothermal but need only produce 48 or 38 kg/s, respectively, if they instead are developed with steam heating or geofluid heating hybrids. In both cases, the use of hybrid systems effectively lowers the minimum quality characteristics a resource needs to meet for it to be developable.

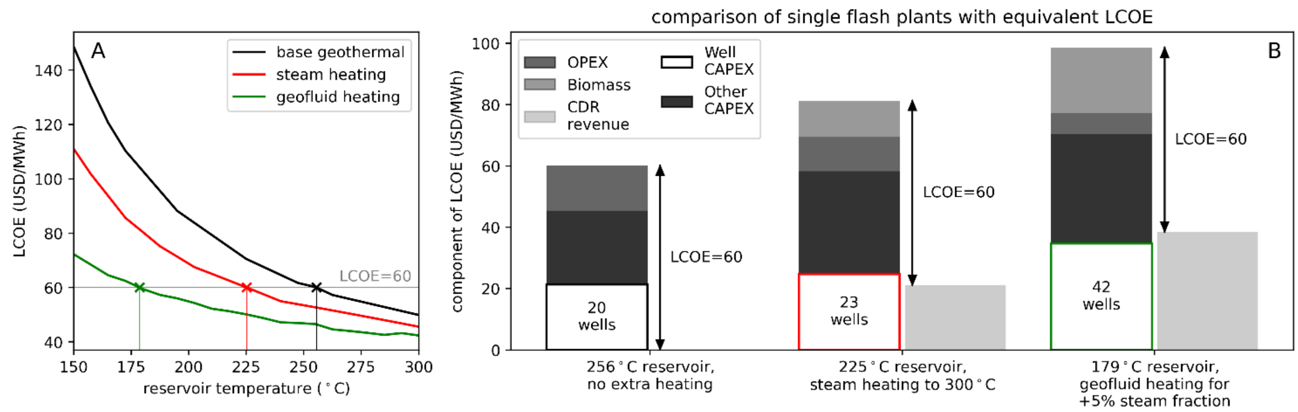

Figure 8: Cost breakdown of the three plant types at different resource temperatures for a reference economic performance of LCOE=60 USD/MWh. (A) Plant types achieve the same performance at different resource temperatures: 256°C for the unhybridized flash plant (black), 225°C for a hybrid plant that heats separated steam to 300°C (red), and 179°C for hybrid plant that increases steam mass fraction by 5% through pre-separation heating (green). (B) Breakdown of cost components. Hybrid plants utilize more marginal (lower temperature) resources by having more wells and topping up with bioenergy. The additional costs of wells and biomass are covered through carbon removal (CDR) revenues.

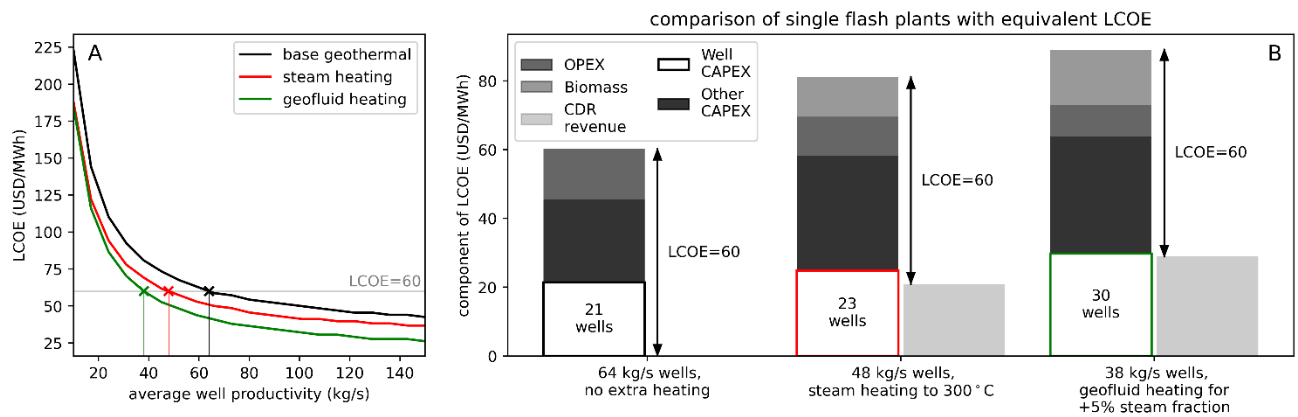

Figure 9: Cost breakdown of the three plant types at different resource productivities for a reference economic performance of LCOE=60 USD/MWh. (A) Plant types achieve the same performance at different average well productivities: 64 kg/s for the unhybridized flash plant (black), 48 kg/s for a hybrid plant that heats separated steam to 300°C (red), and 38 kg/s for hybrid plant that increases steam mass fraction by 5% through pre-separation heating (green). (B) Breakdown of cost components. Hybrid plants utilize more marginal (lower productivity) resources by having more wells and topping up with bioenergy. The additional costs of wells and biomass are covered through carbon removal (CDR) revenues.

3.5 Reducing barriers to entry for marginal resources

The occurrence of an accessible, high-temperature geothermal system is a relatively rare phenomenon (Fig. 10A). For example, among 178 geothermal resources developed globally with steam turbine power cycles (Wilmarth et al., 2021; Dempsey et al., 2023), only 20% exploit a reservoir with a temperature higher than 300°C, and only 5% of binary plants operate above this range (Fig. 10B). Hochstein (1990) estimates that 95% of all resources are in the intermediate-to-low temperature range below 225°C. Thus, the pool of future geothermal opportunities is constrained by the relative scarcity of attractive resources, and this constraint becomes more acute at higher temperatures.

On the other hand, there are clearly also lower limits to the temperature of geothermal reservoirs that are developed. For plants using steam turbines, developments are typically restricted reservoir temperatures above 200°C (Fig. 10B). For binary plants, the limit is lower, about 100°C. Amongst other considerations, these low temperature limits reflect the ability of different plant technologies to economically generate electricity from marginal resources. This same temperature dependence is built into models of LCOE that are discussed here (Fig. 5B).

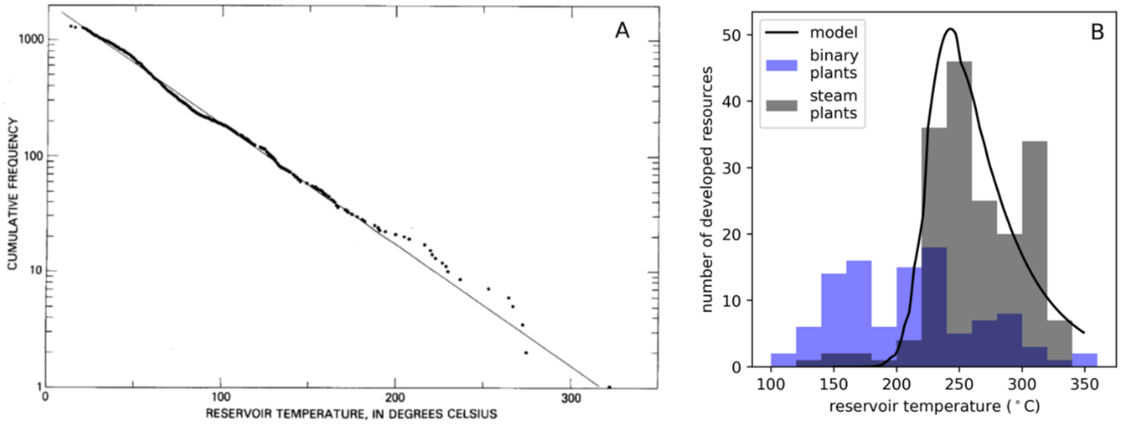

Figure 10: Distribution of developed and undeveloped geothermal systems by temperature. (A) Cumulative distribution of 1346 hydrothermal-convection systems in the US, with exponential model fit (black line), from Reid (1982). (B) Distribution of reservoir temperatures of 178 developed geothermal systems utilizing steam condensing turbines (black), e.g., single-flash, double-flash, dry steam, and 104 systems utilizing binary plants (blue). Black line indicates a theoretical model fit to the steam plants (see Fig. 11).

In order for us to speculate on the expanded pool of geothermal resource available to hybrid systems, we need to account for both resource availability (by temperature) as well as techno-economic feasibility. For the former, we propose a relationship between for the relative abundance of all geothermal resources hotter than 150°C, of which the developed systems (Fig. 10B) are only a subset. Here, we use an exponential function based on temperature with scaling parameter σ_T=41.5°C, to approximate the relative abundance of all resources (p_{geo}) with temperatures higher than 150°C (Fig. 11B, dashed line)

$$p_{geo}(T) = A \exp\left(-\frac{T}{\sigma_T}\right). \tag{9}$$

This model is in accordance with the distribution of geothermal system temperatures compiled by Reid (1982) for the United States (Fig. 10A), although we acknowledge the parameters may change when data are available to include other countries.

Next, we use the LCOE of a plant to estimate the likelihood that a resource will be developed, $p_{econ}(LCOE)$, assuming that lower LCOEs make developments less risky and hence more likely to occur. We have used a sigmoid curve to describe this relationship, centering it at the 2021 weighted average of μ_L=68 USD/MWh and with a scale parameter of σ_L=4 USD/MWh (Fig. 11A)

$$p_{econ}(LCOE) = 1 - \left(1 + \exp\left(-\frac{LCOE-\mu_L}{\sigma_L}\right)\right)^{-1}. \tag{10}$$

Taking the product of these two models, with LCOE a function of temperature, yields an approximation for the temperature distribution of economically developable systems:

$$p_{dev} = p_{all}(T)\, p_{econ}(LCOE(T)). \tag{11}$$

We estimated the two distributions' shape parameters, σ_L and A, by fitting to the distribution of steam-turbine developed geothermal systems (Fig. 10B), using the base geothermal model (Fig. 3B) for $LCOE(T)$. Once σ_L and A were determined, we fixed their values but repeated the calculation using LCOE curves for steam and geofluid heating hybrids (Fig. 5B) to estimate the corresponding number and distribution of systems that are developable under hybrid conditions (Fig. 11B).

First, this analysis strengthens the argument that, appropriately deployed, new geothermal technologies can reduce the threshold resource characteristics that separate marginal systems from economic ones. This is reflected in the distribution of developed system temperatures using steam turbines (>200°C) and the comparatively wider range achieved with modern binary technology (>100°C). Our model predicts a similar expanded range of developability when using geothermal-bioenergy carbon-removing hybrids, as evidenced in Fig. 11B by the leftward shift of the lower-temperature extent of the economic system range.

Second, the major opportunity for geothermal-bioenergy hybrid systems lies in exploiting lower-temperature resources that might otherwise be classified as marginal. This is evidenced by the leftward shift of the center economic system distribution, from 240°C for base geothermal, to 205°C for steam heating hybrids, and 165°C for geofluid heating hybrids. Finally, the size of the opportunity for the geothermal sector increases appreciably for new technologies that lower the resource barrier to entry. This is evidenced by an increasing area under the respective economic distribution curves, from 178 resources for base geothermal, to 366 and 1007 resources for steam and geofluid heating hybrids, respectively.

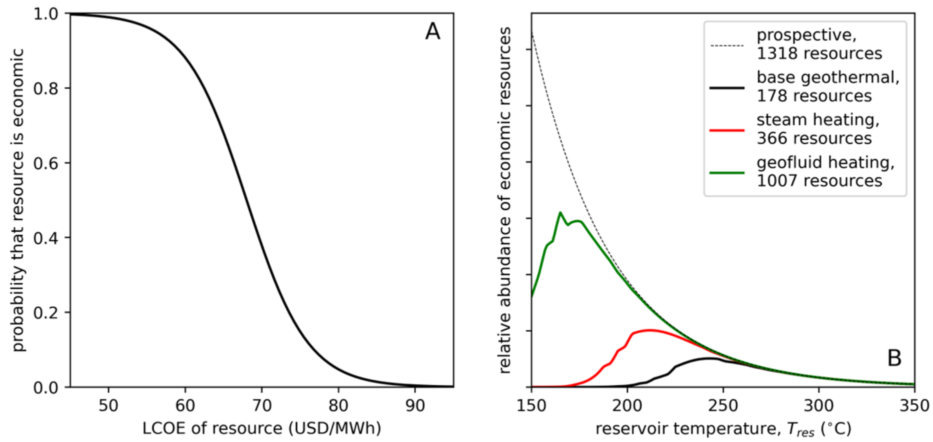

Figure 11: Theoretical model of marginal resource availability when considering hybrid plant designs. (A) Logistic model linking LCOE to likelihood that a resource is economic. (B) Extrapolation of the model for hybrid plant designs that exploit improved economics at lower temperatures (Fig. 8A). A greater proportion of marginal (lower temperature) systems are exploitable for hybrid designs.

It is important to caution that the estimation of the developable geothermal reserves is somewhat theoretical and subject to change as further data on the abundance of undeveloped geothermal resources is collected. Quantitative findings will certainly shift if alternative parameter values are used or if model assumptions are adjusted or relaxed. This is particularly true where predictions rely on extrapolation outside the well-understood temperature range. Nevertheless, as an academic exercise, we argue that the qualitative trends are likely to be robust and therefore have value for understanding the impact of technological advances on future geothermal development.

4. CONCLUSION

In this study, we have presented a techno-economic analysis of two hypothetical designs of geothermal-bioenergy hybrid plants and evaluated their possible impact on the geothermal sector. First, we modelled the dynamics of simple condensing turbine systems and used this to quantify the cost of base geothermal or hybrid developments in terms of key resource (temperature, productivity) and economic parameters (biomass, CO_2 prices). Then, we calculated how cost curves could shift when accounting for complimentary revenue streams arising from hybridization, namely carbon removal offsets sold when injecting green CO_2 into the reservoir. Finally, we introduced some simple economic and distribution models to explore the likely resource opportunities for the geothermal sector.

Our findings suggest that both steam and geofluid heating hybrids can outperform a standard geothermal plant on a cost basis under reasonable biomass (<140 USD/tBio) and carbon removal prices (>50 USD/tCO_2). Moreover, the reduction of overall project costs brings into frame a large number of resources that may have been considered marginal or uneconomic under standard technology. Biomass heating of geofluid prior to separation was particularly effective at improving the economics of medium enthalpy resources in the range 150 to 200°C, with the added benefit of large rates of negative emissions, exceeding intensities of -1000 gCO_2/kWh.

Project economics are just one consideration when evaluating whether a resource can be developed. A project must also demonstrate that the resource has manageable chemistry, that subsurface storage of the injected CO_2 is secure, and that there is a sufficient and stable supply of sustainably sourced biomass to meet the plant's needs. However, these issues all need to be addressed on a case-by-case basis as part of de-risking future geothermal projects.

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