Techno-economic analysis of a CO_2 direct air capture-cooling tower hybrid process at a geothermal facility

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Abstract: Direct air capture (DAC) of CO_2 can play a crucial role in global efforts to manage atmospheric concentrations of CO_2, but the current cost-of-capture is prohibitively high. In this work we present a new DAC concept whereby cooling towers at geothermal power plants are hybridized to capture CO_2 at very low cost. The system design is elegant in its ability to overcome key technical challenges and highlights the potential for using existing infrastructure to lower DAC cost and land footprint, and secure utilities and public confidence. The techno-economic analysis suggests a cost-of-capture of $100 per metric tonne of CO_2 is feasible, allowing geothermal facilities to increase their net profit by $29 per metric tonne of CO_2 captured — or $6 million per year — under the 45Q tax credit. If deployed at geothermal facilities in the United States, a net reduction of 270 million tonne CO_2 per year is possible by 2050.

Introduction

There is growing evidence that the deployment of negative emission technologies (NETs) which remove atmospheric CO_2 will be more cost-effective than efforts to reduce sources of greenhouse gas emissions (GHGs) in hard-to-abate sectors.[1] Therefore, NETs should be viewed as part of the GHG reduction portfolio rather than as an attempt to reverse historical CO_2 emission. Among NETs, direct air capture (DAC) of CO_2 stands out due to its location independence and essentially unlimited capacity. [1]

Direct air capture technologies generally consist of an air contactor and a CO_2 regeneration system. To remove large quantities of CO_2 from ambient air, where CO_2 is present in low concentrations, it is necessary to bring large quantities of air in contact with a CO_2 capture medium. This is typically achieved with an array of fans that produce enough draft to overcome the internal pressure drop of the air contactor. Common CO_2 capture media are solid sorbents and liquid solutions that readily and selectively bind CO_2. In order to release the CO_2 from the capture medium in the regeneration system, a driving force is applied induced by heat, a chemical potential, pressure change, and/or concentration change, to produce a concentrated CO_2 or CO_2-derivative stream.

While DAC systems themselves are relatively modular, at least on the air contactor side, and agnostic to deployment location, they require significant amounts of new infrastructure, energy, and access to water, capture media and nearby options for the sequestration and/or utilization of the captured carbon. These system-level issues further add to capital and operating expenses, making it difficult to achieve the US Department of Energy's target of $100 per metric tonne of captured CO_2. In comparison, current commercialized DAC systems capture CO_2 at a cost of $500–$1000 per metric tonne of captured CO_2.[2,3]

Several options for lowering the cost-of-capture have been explored, including developing scalable and low-cost equipment,[4–6] more efficient, low-energy regeneration cycles,[6–9] more effective capture media,[7,9] and producing lucrative byproducts, such as the conversion of CO_2 to fuels or the sale of mineralization products for construction.[10,11] Here, we consider another potential approach for lowering the cost-of-capture, which is by hybridizing DACs with existing cooling tower infrastructure.[12] In the proposed approach, the cooling tower simultaneously acts as air contactor for evaporative cooling and for CO_2 capture, leveraging the large liquid-gas contact area inherently found in cooling towers to achieve high CO_2 removal rates, and the large quantities of air that are already being used to drive evaporative cooling.

This is not the first time cooling towers have attracted the attention of the DAC community. In fact, Carbon Engineering acknowledges that part of their technology is based on cooling tower technology,[13] which further highlights synergies between DAC systems and cooling towers. The company Noya has mentioned a concept where they suggest adding equimolar blends of hydroxides and amino acids to cooling towers to capture CO_2.[14] However, solids like hydroxides and amino acids pose a

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fouling risk for cooling towers, leading to performance and reliability concerns. Using liquid capture media, such as monoethanolamine (MEA), would evade this fouling risk, but are hygroscopic in nature and have phase change properties that could negatively impact water evaporation behavior in the cooling tower and lead to evaporative losses of the capture medium itself.

To address these challenges, herein, we present a new concept for a geothermal cooling tower-DAC hybrid system that uses low solvent concentrations to promote CO_2 capture while allowing water to evaporate. We present a comprehensive process model and techno-economic analysis (TEA) to bound system performance and cost. The key innovations of the proposed design are the novel compound mixtures, thermodynamics and system integration that allow for energy efficient CO_2 capture and absorbent regeneration, thereby minimizing the costs associated with the CO_2 capture medium and equipment. Remarkably, we find the system can achieve a cost-of-capture of $85.84 to $169.03 per metric tonne of CO_2.

The results of this study offer critical guidance on the integration of DAC in existing geothermal cooling towers with minimal capital equipment and energy penalty. Furthermore, we solved challenges related to absorbent loss in the cooling tower, challenges related to the regeneration of highly diluted CO_2 capture solvents in water, and challenges related to reducing the cooling water blowdown. By targeting geothermal cooling towers for our first design, we are not limited in our absorbent selection as the blowdown can be reinjected into the geothermal reservoir and the absorbent will degrade rapidly at local temperatures. With these features we are able to substantially reduce operating costs and be more competitive than current DAC solutions.

Hybridization and system integration

While this concept has the potential to be applied to a variety of industrial systems with cooling towers, geothermal power plants are identified as a particularly attractive market for this cooling tower-DAC hybrid system due to the availability of steam and the cooling tower design. Typically, geothermal power plants range from 10 MW to 100 MW in size and often multiple units are located in relatively close proximity within a geothermally active region. In this study an exemplary 50 MW dual flash geothermal facility in California's Salton Sea region is studied. The Salton Sea region has been identified as an important area for DAC as part of California's efforts to reach carbon neutrality with plans to connect the Salton Sea area to the San Joaquin Basin via pipeline where permanent CO_2 storage options exist.[15] At full capacity, a 50 MW plant with this hybrid DAC system is able to capture 265,000 metric tonnes of CO_2 per year. Considering downtime due to maintenance, a carbon capture rate of 225,000 metric tonnes of CO_2 per year is realistic. In 2021, the US produced over 16 billion kilowatt-hours of electricity from geothermal utility-scale facilities.[16] With the plans of the US government to expand geothermal power production by a factor of more than 17 to a capacity of 60 GW by 2050,[17] this hybrid DAC concept has the potential to remove approximately 175 million metric tonnes of ambient CO_2 per year and prevent the venting of another 95 million metric tonnes of CO_2 from these facilities. We estimate that this technology can provide around 16% of the US NETs capacity needed by 2050[1,18] from geothermal facilities alone.

A description of a conventional dual flash facility is provided in the Methods section which further explains the operations, cooling tower design and why geothermal power plants have a CO_2 emission profile. The focus of the following description is the hybridization concept.

To hybridize cooling towers and DAC, a CO_2 capture medium is added to the cooling water. For this scenario, we have identified amines, such as MEA, as particularly suitable as they reduce the fouling risk associated with solids deposition on heat exchanger surfaces and the cooling tower packing. The cooling water with the capture medium can be used like regular cooling water as long as it is not exposed to temperatures exceeding the thermal decomposition temperature (in the case of MEA c.a. 90–110 °C)[19,20] or is in direct contact with a CO_2 carrying stream. In the case of a geothermal power plant the temperature limit is not exceeded, and the water needs for the non-condensable gas quenching and liquid ring vacuum pump (upstream of the Stretford process) can be directly served by the condensate stream, which is free of the capture medium. Instead of mixing the condensate stream with the main cooling water stream upstream of the cooling tower, the condensate stream is injected into the cooling tower above the main cooling water injection to minimize the loss of the capture medium. This minimizes evaporative losses as well as entrainment losses which can be further reduced by the installation of a mist eliminator.

Many liquid CO_2 capture solvents like MEA are hygroscopic, meaning they tend to absorb water. This presents a challenge since cooling towers rely on evaporating water. To solve this conundrum, we identified that MEA concentrations of around 3 wt.-% have the right thermodynamic properties to simultaneously support water evaporation and CO_2 absorption at the gas-to-liquid ratios found in cooling towers. Using lower concentrations of the capture medium helps to reduce evaporative and blowdown losses of the capture medium. Additionally, using "clean" water as cooling tower makeup, such as steam cycle condensate or treated water helps to minimize blowdown losses. While the condensate may contain carryover from the flash drum, adding anti-foaming additives, employing a water wash, or installing mist eliminators can improve condensate quality. In geothermal power plants, the blowdown of the cooling tower is re-injected into the geothermal reservoir offering greater flexibility in terms of capture medium selection as it eliminates some environmental concerns regarding the blowdown discharge. Capture media like MEA are expected to rapidly decompose in the geothermal reservoir.

The selection of low-concentration ranges for the solvent requires the development of a novel regeneration process. In this process, direct steam injection into a stripper column is used instead of a reboiler. Once condensed, it acts as cooling tower makeup. However, the regeneration of low-concentrated solutions leads to a high water mole-fraction in the overhead product of the stripper. To recover some of the latent heat, a compressor is used to increase the dewpoint temperature to a level where it becomes accessible for stripper feed pre-heating. To achieve regeneration at a temperature close to the supply steam's temperature only a portion of the cooling water is treated in the regenerator, which is more favorable than treating all cooling water at a lower temperature. By combining these measures, an effective regeneration of low-concentrated solutions is possible resulting in a CO_2 stream with a purity of 94.6 mol.-%. After compression and intercooling the concentration increases to 98.6 mol.% with trace amounts of nitrogen, oxygen, water and H_2S. The CO_2 vent from the Stretford process, which is typically considered as too small to be captured, can be added to the DAC's CO_2 stream to improve the overall environmental impact of the geothermal facility. Since compression is capital-intensive, a central CO_2 compression unit can be used that supports several plants in the area. An illustration of the system is provided in **Figure 1**.

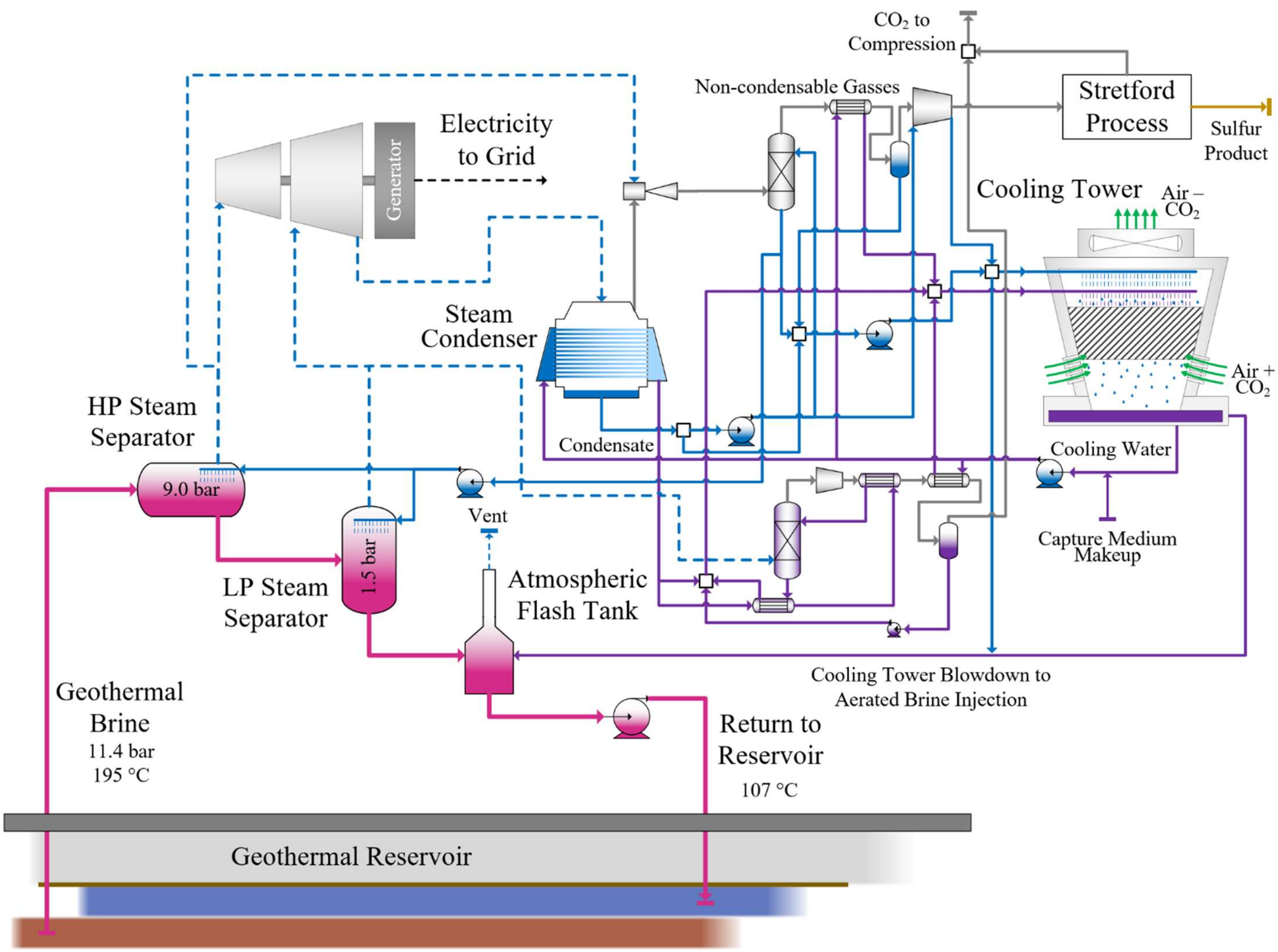

Figure 1: Simplified flowsheet of the cooling tower-direct air capture hybrid concept.

Performance and economics

In this section we compare the performance of a conventional 50 MW geothermal power plant (Base Case) to a geothermal power plant with the new cooling tower-DAC hybrid (Hybrid DAC) technology. The conventional geothermal power plant produces 56.4 MW of gross power using a high-pressure turbine (17.7 MW) utilizing the steam from the first flash drum and a low-pressure turbine (38.8 MW) utilizing the outlet from the high-pressure turbine and the steam from the low-pressure flash drum. In the Hybrid DAC Case the gross power generation decreases to 45.2 MW, with the low-pressure turbine power output reduced by 29% due to steam extraction for the solvent regeneration unit.

In the Base Case, the auxiliary loads account for 6.4 MW while in the DAC Hybrid Case they increase to 17.1 MW. The largest contributors to the auxiliary loads in the Base Case are the brine injection pump (42%) and the cooling water pumps (29%). Although the absolute power consumption of the brine injection remains almost constant between the two cases, the Hybrid DAC Case requires additional pumping power due to the solvent regeneration process. Moreover, the overhead product compressor in the regeneration unit (6.8 MW) and CO_2 compressors for pipeline transport (3.4 MW) add significant parasitic power loads to the Hybrid DAC case. As a result, the net power generation decreases from 50.0 MW to 28.1 MW, and the lost electricity sales revenue must be compensated by the sales revenue from CO_2, which determines the minimum gate price. **Table 2** summarizes the balance-of-plant. An alternative solution for the geothermal facility would be to enter a power purchase agreement (PPA) or purchase electricity through a Renewable Energy Certificate (REC) program, which would cost between 30–50 $/MWh, cheaper than the levelized cost of geothermal energy. It is worth noting that the DAC systems proposed today are designed to consume dedicated geothermal or renewable electricity, and the same is true for this technology.

The Base Case has a plant cost of $141.5 million while the Hybrid DAC Case costs $188.7 million, representing a 33% increase. Although the cost for wells, tanks, and vessels as well as the vacuum system remains essentially unchanged, a cost saving of approximately $7.4 million on the steam cycle equipment and generator is observed due to lower steam availability in the Hybrid DAC Case, which leads to a downsizing of the steam turbine island. However, the majority of cost increases originate from the CO_2 regeneration and compression equipment, which costs $34.8 million and $10.8 million respectively. Moderate equipment cost increases are observed for the cooling tower, pumps and drives, piping, instrumentation, electrical, structures, and miscellaneous costs. The resulting specific capital investment of the DAC system based upon the annual removal capacity is $178 per metric tonne of CO_2. This is substantially cheaper than current DAC investment costs ranging from $556 – $1146 per metric tonne of CO_2.[21] In some cases, the contactor alone can account for as much as $290 per metric tonne of CO_2.[7] A side-by-side breakdown of the plant's capital costs is provided in **Table 1**.

Aside from capital investment, the cost-of-electricity depends on fixed and variable operating expenditures. In the Base Case annual labor costs amount to $5.0 million, and tax and insurance account for another $2.8 million per year. Variable operating costs include maintenance materials, chemicals (primarily scale removal), and waste disposal which cost $1.3

Table 2: Comparison of the Balance-of-Plant

		Base Case	Hybrid DAC
Power Generation	Unit	Value	Value
HP Turbine	kW_e	17,680	17,690
LP Turbine	kW_e	38,750	27,520
Total Power Generation	kW_e	56,430	45,210
Auxiliary Load	Unit	Value	Value
Brine Injection Pump	kW_e	2,680	2,600
Water Pumps	kW_e	1,850	2,340
Vacuum Pump	kW_e	620	720
Cooling Tower	kW_e	880	910
CO_2 Compression	kW_e	N/A	3,440
CO_2 Regeneration	kW_e	N/A	6,830
Miscellaneous	kW_e	190	140
Transformer	kW_e	210	120
Total Auxiliary Load	kW_e	6,430	17,100
Net Power Generation	kW_e	50,000	28,110

Table 1: Comparison of the Plant Cost

		Base Case	Hybrid DAC
Equipment	Unit	Value	Value
Wells	$1,000	29,900	29,800
Tanks and Vessels	$1,000	5,100	5,100
Steam Cycle	$1,000	44,200	36,800
Vacuum System	$1,000	10,700	10,800
Stretford Process	$1,000	6,300	5,600
Cooling Tower	$1,000	17,500	19,100
Pumps and Drives	$1,000	3,800	4,500
CO_2 Compression	$1,000	N/A	10,800
CO_2 Regeneration	$1,000	N/A	34,800
Piping, Instr. & Electrical	$1,000	12,400	14,800
Civil & Structural	$1,000	8,200	11,900
Yardwork & Miscellaneous	$1,000	3,200	4,700
Total	$1,000	141,500	188,700

million, \$0.5 million and \$1.9 million per annum, respectively. The by-product revenue from sulfur is negligibly small at \$30,000. As a result, the costs-of-electricity is \$66.59 per MWh.

In the Hybrid DAC Case, the labor expenses increase to \$5.4 million due to additional costs associated with operating the solvent regeneration equipment. Insurance and tax expenses increase to \$3.7 million per year due to higher capital expenditures. Maintenance material costs increase to about \$1.9 million per year; however, the largest increase in variable operating costs is due to the replacement of the capture medium with \$5.5 million per year. Thus, to maintain an electricity sales price of \$66.59 per MWh, CO_2 needs to be sold at a price of \$100.57 per metric tonne (cost-of-capture includes compression to 80 bar). A breakdown of the cost-of-electricity for the two cases is provided in **Figure 2**. The reduced power output is the largest cost driving factor for the cost-of-capture accounting for \$48.20. Operating costs are responsible for \$32.42, mainly due to solvent expenses, while capital expenditure-related costs amount to \$19.95.

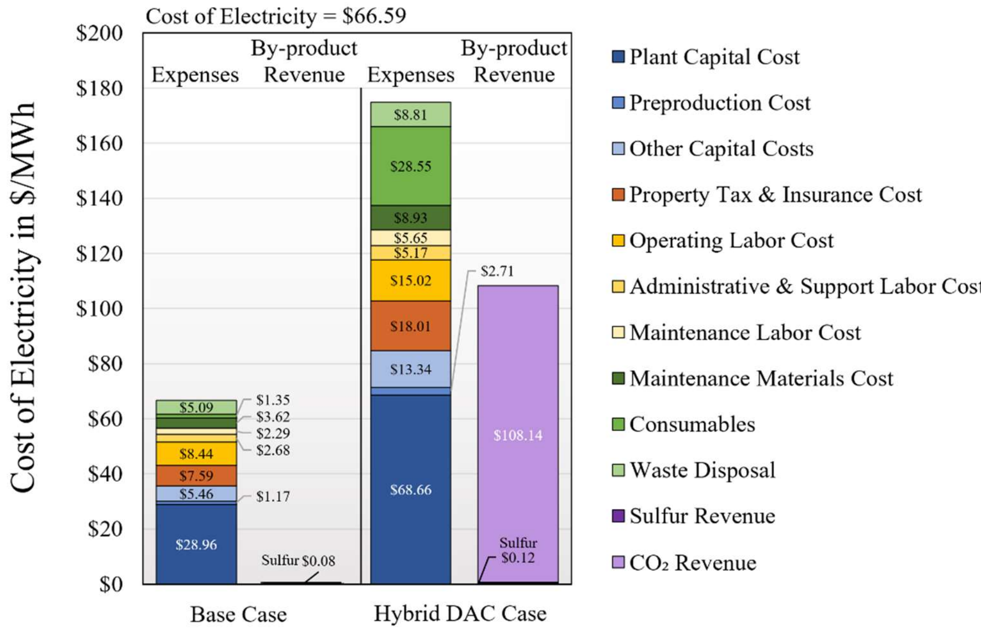

Figure 2: Comparison of cost-of-electricity breakdowns of the geothermal base case without carbon capture and the cooling tower-DAC hybrid cases with carbon capture.

Considering Section 45Q credits for carbon oxide sequestration, the power facility can earn an income stream of \$144.30 per metric tonne of CO_2, which includes \$85 per metric tonne for permanently stored CO_2 from captured sources, i.e., the non-condensable gas, and \$180 per metric tonne of CO_2 from DAC. Sequestration sites in California are currently being explored in the Bakersfield region and the 320-mile pipeline transport and injection will add another \$15.12 per metric tonne of CO_2 to the cost-of-capture (adjusted to 2022 cost basis).[15] This demonstrates that carbon capture at this power facility can increase its annual net profit by \$6.0 million per year.

This cost-of-capture is highly competitive and presents one of the first viable business cases for direct air capture. Due to the variability of geothermal plant sizes, we further investigated the cost-of-capture for a series of plant sizes ranging from 10 MW to 100 MW (based on size of respective geothermal power plant without hybrid DAC), as shown in **Figure 3**. At smaller scales, the cost-of-capture increases exponentially, with a cost-of-capture of \$169.03 per metric tonne of CO_2 at a 10 MW scale. At a scale of 100 MW the cost-of-capture decreases to \$85.84 per metric tonne of CO_2, indicating economic viability for plants of 20 MW or larger.

With solvent replacement being a considerable operating expense, we studied the impact of improved blowdown water management. The results show that improved blowdown management can further reduce the cost-of-capture and even at higher blowdown rates the cost-of-capture does not exceed \$159.25 per metric tonne of CO_2, indicating economic viability up to a blowdown rate of 47,000 kg/h.

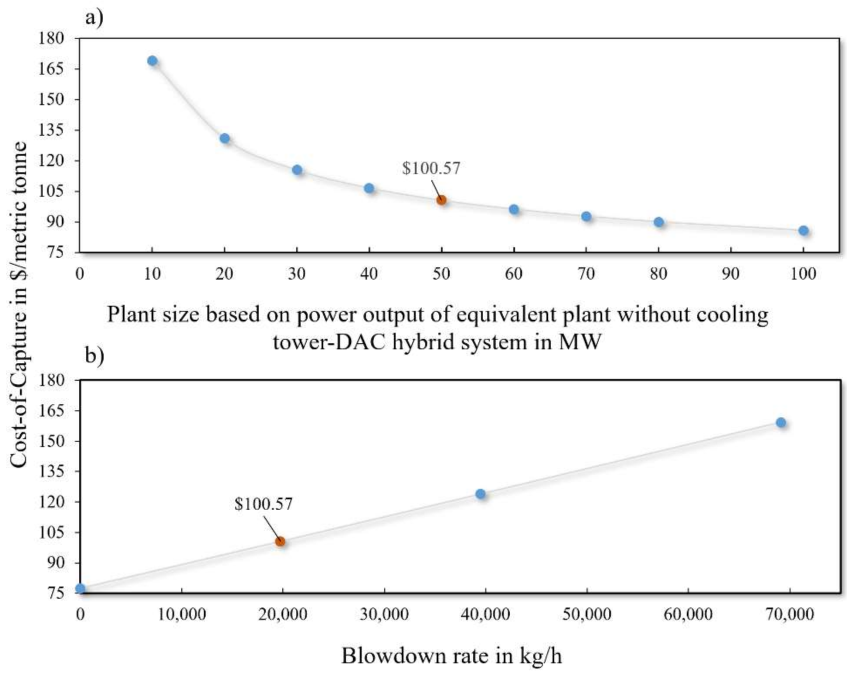

Figure 3: Sensitivity of cost-of-capture with respect to plant size (a) and cooling tower blowdown rate (b).

Future outlook

Geothermal power generation is a crucial technology for reducing CO_2 emissions in the energy sector. However, despite being a low-emission source of electricity, geothermal electricity generation is not completely GHG emission-free and needs to become more cost-competitive in the long run. Furthermore, geothermal energy has been identified as an important part of advancing DAC technology. In this study, we identified a new cooling tower-DAC hybrid system that can address these challenges, allowing geothermal facilities to operate without venting CO_2 from the reservoir, capturing CO_2 from ambient air, and increasing the net profit margin of these facilities, which translates to lower electricity prices.

We find geothermal power plant cooling tower-DAC hybrid systems can capture CO_2 at a levelized cost of $85.84 to $169.03 per metric tonne of CO_2, meeting the US DOE target before employing tax incentives such as the tax credit for CO_2 storage allotted under 45Q. With the tax credit, we conclude that it is very possible for the facility to make a profit as much as $43.34 per metric tonne of CO_2. While this work shows the enormous potential of this hybridization concept, more research is needed for process optimization and experimental validation. Cooling tower water management and cooling tower blowdown management will be key areas of research needed to advance this technology. Once these fundamental questions are answered, this technology is expected to make rapid progress towards commercialization as it uses common plant equipment and does not rely on new unproven materials and manufacturing techniques. The reliance on proven technology and synergistic integration with existing cooling towers will further simplify retrofitting existing plants with this technology.

Methods

Conventional dual-flash geothermal power plant

In a conventional dual flash geothermal power plant, hot brine is sourced from a geothermal reservoir to generate steam by stepwise reducing the pressure in two sequential flash drums, i.e., 9 bar and 1.5 bar. The brine is then reinjected into the reservoir and the steam is expanded in a steam turbine to generate electricity. Downstream of the steam turbine the low-pressure vapor is condensed using cooling water. Some non-condensable gases, mainly CO_2 and H_2S, are removed from the condenser via a vacuum system that feeds the non-condensable gases into a sulfur recovery process, the Stretford process, and the remaining CO_2-rich gas is vented into the atmosphere. Carbon dioxide emissions due to this practice are 207 kgCO_2/MWh, which is as much as 60.5% of the emissions of a state-of-the-art F-class natural gas combine cycle power plant.[22] The condensate leaving the condenser acts as cooling water makeup to compensate evaporative water loss in the cooling circuit and is mixed with the cooling water before the cooling water is returned to the cooling tower. In the cooling tower, the cooling water is dispersed on top of the cooling tower packing to create a large exchange surface area with ambient air that enters the cooling tower at the bottom and moves upwards through the packing. As the air gets in contact with the cooling water, water starts evaporating which extracts energy from the remaining cooling water restoring its cooling function. With water constantly evaporating, minerals and trace components in the water circuit start building up and a water blowdown is needed. The blowdown is mixed with the geothermal brine before it is re-injected into the reservoir. An illustration of this process is provided in **Figure 4**.

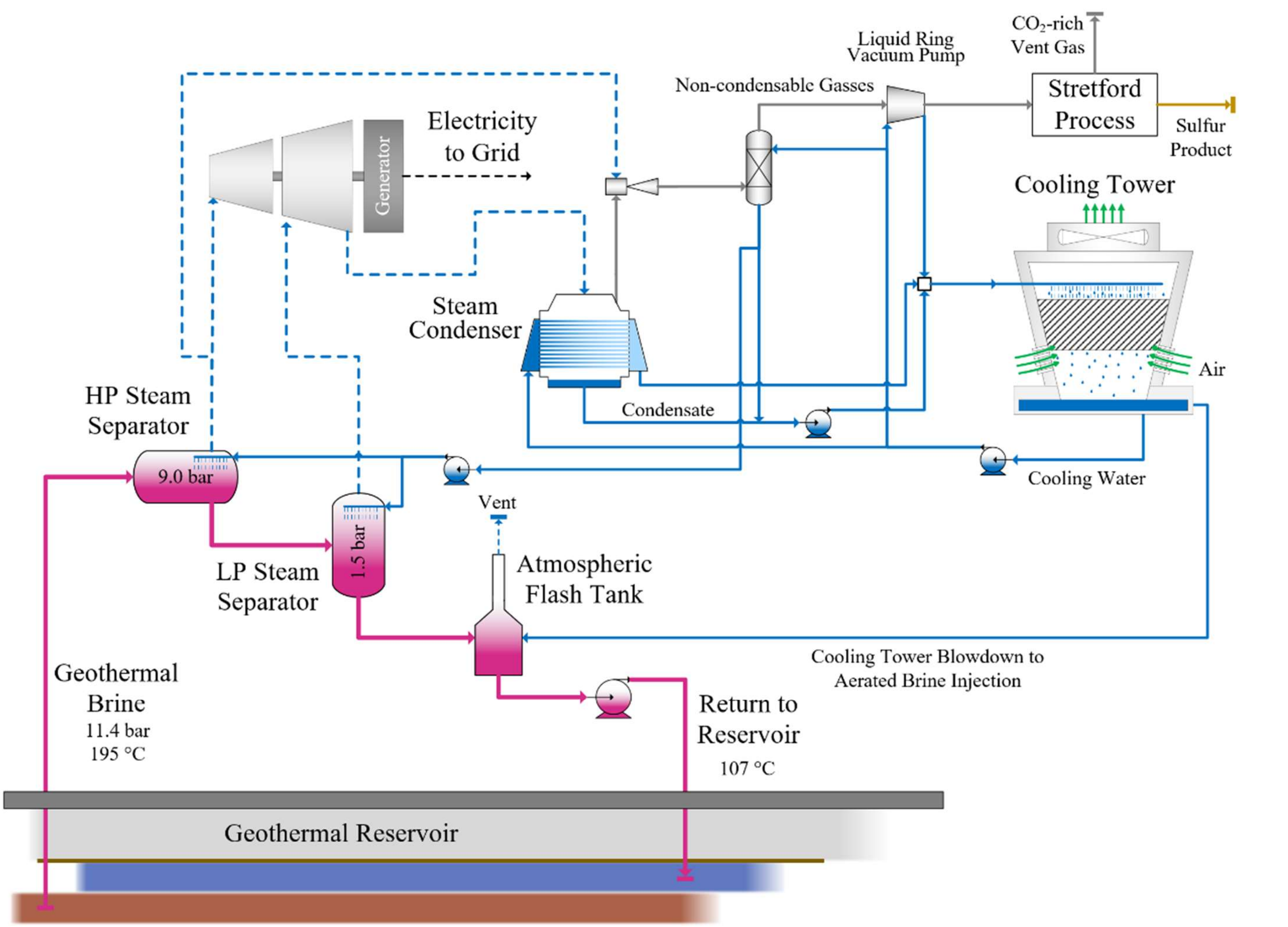

Figure 4: Simplified flowsheet of a conventional dual-flash geothermal power plant.

Modelling

Process models have been developed in the process simulation software ProSim[23] to estimate thermodynamic performance parameters that served as inputs for the performance and economic analysis. The cost analysis is conducted for the year 2022. The plant is assumed to be located in the Salton Sea with an annual average ambient temperature of 22 °C, average annual humidity of 36%, and average ambient pressure of 1.016 bar[24] leading to a wet bulb temperature of 13.3 °C. Ambient air CO_2 concentration has been assumed to be 415 ppm.[25]

The geothermal reservoir has a well head pressure of 10.3 bar and the brine has a temperature of 190 °C.[26] Brine composition was simplified to reduce complexity and modeled with 21.20 wt.-% NaCl, 0.49 wt.-% CO_2 and 41 ppm H_2S.[26]

The steam produced in the flash drums is scrubbed with water to limit salt carryover before it enters the turbines at a state close to saturation. The steam turbine performance is calibrated with performance data from literature.[26] The turbine outlet pressure is 0.16 bar and set by the cooling water temperature in the condenser which leads to a condensate temperature of 39 °C. Generator losses are accounted for in the mechanical and electrical losses of the turbines with 99.1% and 98.3% respectively.

The Stretford process converts the hydrogen sulfide present in the non-condensable gas stream leaving the condenser to elemental sulfur. The reaction is catalyzed by vanadium oxide but also sodium carbonate plays a role in the absorption of hydrogen sulfide. The overall reaction rate can be written as:

$$\mathrm{H_2S} + 0.5\,\mathrm{O_2} \rightarrow \mathrm{S} + \mathrm{H_2O} \tag{1}$$

The sulfur formation occurs immediately once the hydrogen sulfide is absorbed into the scrubber solution and the catalyst is regenerated via the liquid oxidation reaction with dissolved molecular oxygen in a froth tank.[27]

The cooling tower is modeled with an approach temperature of 5 °C,[22,28] a range of 15 °C[26] which was achieved with three stages using a stage efficiency of 70% to account for non-ideal behavior and kinetic limitations.[29] In the hybrid cooling tower a spray injection system is installed above the first stage to minimize solvent evaporative losses which is also assumed to reach a stage-efficiency of 70%. The chemical reactions governing CO_2 absorption are summarized below.

$$\mathrm{H_2O} \rightleftharpoons \mathrm{H^+} + \mathrm{OH^-} \tag{2}$$

$$\mathrm{H_2O} + \mathrm{CO_2} \rightleftharpoons \mathrm{H^+} + \mathrm{HCO_3}^- \tag{3}$$

$$\mathrm{HCO_3}^- \rightleftharpoons \mathrm{H^+} + \mathrm{CO_3}^{2-} \tag{4}$$

$$2\mathrm{MEA} + \mathrm{CO_2} \rightleftharpoons \mathrm{MEAH^+} + \mathrm{MEACOO^-} \tag{5}$$

$$\mathrm{MEAH^+} \rightleftharpoons \mathrm{H^+} + \mathrm{MEA} \tag{6}$$

Carbon dioxide compression is accomplished in a three-stage compression train with intercooling. Compressors operate at a compression ratio of 4 to limit the discharge temperature to below 200 °C and compressor isentropic efficiencies vary from 71.5% to 72.5%.

Economics

Capital cost estimates are based on literature[26,30] and individual cost correlations from ProSim. Cooling tower cost has been estimated using a correlation that corrects for changes in operating conditions of the cooling tower, such as flow rate, approach temperature, cooling tower range, and design wet bulb temperature. All equipment has been scaled based on equipment-specific scaling exponents[30] and adjusted to 2022-dollar using CEPCI.

The capital charge factor is 0.0763 based upon a 2.5-year capital expenditure period of 10%, 25%, 35%, 20%, 10% per half year. Plant operation is assumed to be 30 years and capital depreciation is over 20 years (150% declining balance). The project is financed by 45% equity and 55% by debt at an after-tax weighted average cost of capital of 4.73%. Federal tax is 21% and State tax is 6%.[31] The plant's capacity factor is assumed to be 85%.[26] Besides operating and maintenance labor, major operating costs are shown in **Table 3**.

Table 3: Operating Costs

Item	Unit Cost
Scale removal (plant), per tonne of scale removed	$57[26]
Scale removal (field piping), per 1000 tonnes of brine extracted	$3.7[26]
Scale disposal, per tonne of scale	$120[32]
MEA, per tonne of MEA	$1200[33]
Sulfur by-product, per tonne of sulfur	$450[34]
CO_2 pipeline transport, per tonne of CO_2	$7.09[15]
CO_2 injection, per tonne of CO_2	$8.03[15]
CO_2 credit sequestration, per tonne of CO_2	$85[35]
CO_2 DAC credit sequestration, per tonne of CO_2	$180[35]

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Author Contributions

Conceptualization (F.R.), Methodology (F.R., A.S.), Software (F.R., A.S.), Formal Analysis (F.R., A.S.), Investigation (F.R., A.S., H.B.) Visualization (F.R.), Writing (F.R., H.B.), Supervision (F.R., H.B.), Resources (H.B.), Funding (H.B.)

Competing Interests

The authors (F.R. and H.B.) declare the following competing interests: Lawrence Berkeley National Laboratory has filed patent applications related to this paper. The other authors declare no competing interests.

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