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A Hybrid Geothermal Energy Conversion Technology - A Potential Solution for Production of Electricity from Shallow Geothermal Resources

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Abstract

Geothermal energy has been successfully employed in Switzerland for more than a century for direct use but presently there is no electricity being produced from geothermal sources. After the nuclear power plant catastrophe in Fukushima, Japan, the Swiss Federal Assembly decided to gradually phase out the Swiss nuclear energy program. Deep geothermal energy is a potential resource for clean and nearly CO_2-free electricity production that can supplant nuclear power in Switzerland and worldwide. Deep geothermal resources often require enhancement of the permeability of hot-dry rock at significant depths (4-6 km), which can induce seismicity. The geothermal power projects in the Cities of Basel and St. Gallen, Switzerland, were suspended due to earthquakes that occurred during hydraulic stimulation and drilling, respectively. Here we present an alternative unconventional geothermal energy utilization approach that uses shallower, lower-temperature, naturally permeable regions, that drastically reduce drilling costs and induced seismicity. This approach uses geothermal heat to supplement a secondary energy source. Thus this hybrid approach may enable utilization of geothermal energy in many regions in Switzerland and elsewhere, that otherwise could not be used for geothermal electricity generation. In this work, we determine the net power output, energy conversion efficiencies, and economics of these hybrid power plants, where the geothermal power plant is actually a CO_2-based plant. Parameters varied include geothermal reservoir depth (2.5-4.5 km) and turbine inlet temperature (100-220°C) after auxiliary heating. We find that hybrid power plants

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outperform two individual, i.e., stand-alone geothermal and waste-heat power plants, where moderate geothermal energy is available. Furthermore, such hybrid power plants are more economical than separate power plants.

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Keywords: CO_2 Plume Geothermal (CPG) energy; auxiliary heating; hybrid system; carbon capture utilization and sequestration (CCUS);

1. Introduction

In Switzerland geothermal energy has been successfully employed for direct use for more than a century but there is no electricity production from geothermal resources. However, after the nuclear power plant catastrophe in Fukushima, Japan, the Swiss Federal Assembly decided to gradually phase out, or at least reduce, its reliance on nuclear energy, which plays a major role in both electricity production and district heating. Deep geothermal energy is considered to be a potential resource for electricity production that can supplant nuclear power both in Switzerland and worldwide. But, deep geothermal resources often require permeability enhancement of the hot-dry, and thus low-permeability, rock at significant depths (4-6 km), which can induce seismicity. The geothermal power projects undertaken in the Cities of Basel and St. Gallen, Switzerland, were suspended due to the earthquakes that occurred during hydraulic stimulation and drilling, respectively. Alternatively, if a naturally permeable shallow geothermal resource is combined with an additional, or secondary, energy source that is ideally renewable (like solar, biomass or waste heat), but could also be non-renewable (like natural gas), the thermodynamic quality of the delivered energy increases, thereby potentially enabling use of the combined energy sources for economically viable electricity generation. Under certain conditions, such a hybrid power plant, consisting of a geothermal and a secondary plant with the secondary plant heating the geothermally preheated working fluid upon production from the reservoir, can outperform two individual, i.e., stand-alone, plants (one geothermal) and increase the overall energy conversion efficiency of the combined system [1]. The cost for electricity production can also be reduced by operating a single hybrid power plant, when compared to operating two individual plants [2].

Hybrid geothermal power plants can further be combined with carbon capture and storage (CCS), resulting in a CO_2-based geothermal systems [3] such as a CO_2-Plume Geothermal (CPG) systems [4, 5]. Such CO_2-based geothermal systems employ CO_2 as the subsurface geothermal working fluid which, in the hybrid system, becomes the geothermally preheated fluid, further reducing CO_2 emissions. Hence, in this work we model auxiliary heating of CPG systems with waste heat to determine the physical (e.g., net power, thermal efficiencies) and economic (e.g., capital cost) performances and compare them with the individual, stand-alone power plants, i.e., one geothermal and one waste-heat power plant.

2. Hybrid CPG System: Numerical Model

2.1. Subsurface Model

A two-dimensional (2D) radial, axisymmetric, multiphase (water/brine and CO_2) fluid and heat transfer reservoir numerical model is employed in TOUGH2 [6] with ECO2N [7] EOS with the cold injection fluid entering the reservoir centrally through a vertical injection well; the heated fluid is produced from a horizontal, circular 0.33m-diameter production well placed just beneath the impermeable caprock, as described in detail in Garapati et al. [8]. The reservoir parameters are listed in Table 1. As we consider injection of 10 Mt of CO_2 over 2.5 years prior to CO_2 production, the CO_2 plume should, according to Garapati et al. [8], be sufficiently large, that at least 94% of the fluid produced from the reservoir is CO_2 during the production phase – the remaining 6% being water/brine.

2.2. Surface power plant model

The CO_2 flow path through the reservoir, the wells, and the surface power plant are illustrated in Fig. 1. The cold CO_2 is injected at the surface at State 1, where it travels down the injection well to State 2, compressing adiabatically to a supercritical fluid within the injection well. The supercritical CO_2 flows through the reservoir and heats up to the reservoir temperature, reaching the bottom of the production well at State 3. The CO_2 then rises adiabatically [9] through the production well to the surface at State 4. At the surface, the CO_2 is further heated isobarically in an auxiliary heater by a waste heat recovery stream (100-220°C) to State 5. The heated fluid is expanded through a turbine for power production to State 6, where the pressure is set to 10 kPa above the saturation pressure of CO_2 at 22°C. The fluid is then cooled and condensed isobarically to an approach temperature of 7°C above the ambient air temperature of 15°C i.e., 22°C, which is selected based on Adams et al. [10]. The cooled CO_2 is either pumped or throttled from State 10 to State 1. The surface power plant parameters are listed in Table 2. For a geothermal power plant alone, the model remains the same except there is no heating from State 4 to 5. In this case the CO_2 produced to the surface (State 4) is directly expanded in the turbine for power production to State 6. In contrast, for the Secondary Power plant alone, without geothermal preheating, the CO_2 is pumped from State 8 to State 4 directly.

Table 1 Model and physical parameters of the geothermal reservoir

Model Parameters	
Configuration	Radially symmetric about the injection well
Number of grid cells, vertical	34 non uniform layers with fine grid at the top of the reservoir
Number of grid cells, horizontal	50 logarithmically spaced with fine grid around injection and production wells.
Reservoir thickness	300 m
Well spacing	707 m
Lateral boundary condition	No heat or fluid flow
Vertical boundary condition	No fluid flow; heat conduction using TOUGH2 semi-analytic model
Primary system fluids	CO_2
Reservoir Parameters	
Rock density	2650 kg/m^3
Rock specific heat	1000 J/kg/°C
Total model domain radius	100,000 m
Geothermal gradient	35 °C/km
Fluid Property	
Native brine NaCl saturation [ppm]	200,000
Relative permeability & Capillary pressure	van Genuchten (1980) function
Residual brine saturation fraction	0.30
van Genuchten, m	0.457
Residual CO_2 saturation	0.05
van Genuchten a [1/Pa]	5.1×10^{-5}

Table 2 Model parameters of surface power plant.

Power Plant Constants	Value
Secondary (ORC) system fluid	CO_2
Down-hole production well pressure	Hydrostatic
Direct turbine isentropic efficiency	78%
Pump isentropic efficiency	90%

Well pipe material	bare CR13
Well pipe diameter	0.33 m
Well pipe roughness	55 μm [11]
Condensing or cooling tower approach *T*	7 °C
Ambient temperature	15 °C
Heat Exchanger Log Mean Temperature Difference (LMTD)	7 °C

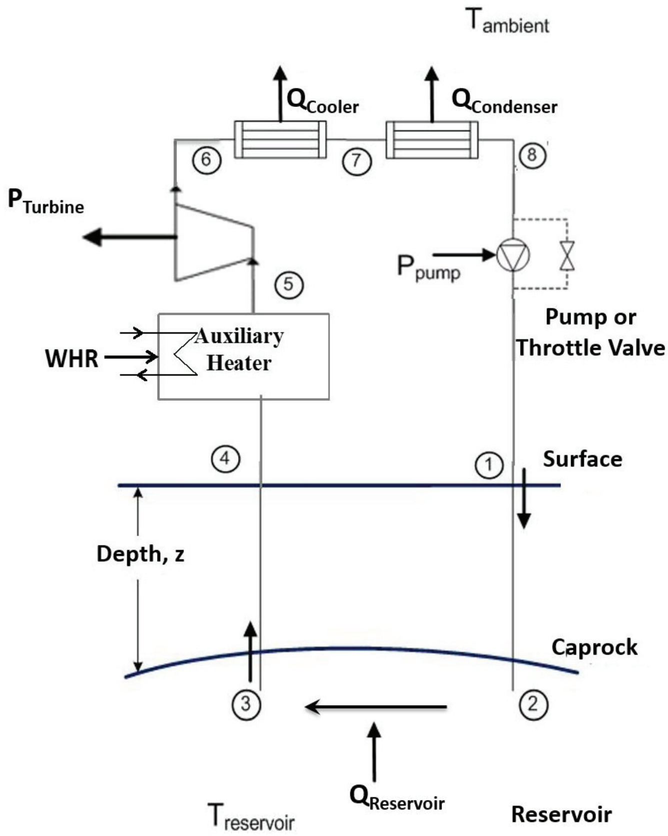

Fig. 1. Simplified process flow diagrams for a direct CO_2 hybrid system (modified from Adams et al., 2015).

3. Analysis

3.1. Thermodynamic Analysis

Power output and efficiency are calculated for reservoir depths of 2.5 km, 3.5 km, and 4.5 km, where reservoir temperature increases with depth according to a standard continental-crust geothermal gradient of 35°C/km, using a waste-heat recovery stream at temperatures of 100°C, 140°C, 180°C, and 220°C for auxiliary heating of the geothermally preheated CO_2. For each configuration, the results are compared to a geothermal plant without auxiliary heating and a secondary-source (here waste-heat) power plant without geothermal preheating.

3.1.1 Net Secondary Thermal Efficiency (NSTE)

The first metric used to compare the operation of a hybrid plant is the Net Secondary Thermal Efficiency (NSTE), defined as

$$\eta_{th,Sec} = \frac{P_{Net}}{Q_{sec}}, \tag{1}$$

which is the net power output of the hybrid plant, P_{Net}, divided by the thermal input of the secondary energy source, Q_{Sec}, i.e., the amount of secondary heat energy added to heat the fluid to the specified turbine inlet temperature. This value specifies the conversion efficiency of the hybrid plant. As the fraction of heat input into the hybrid plant from geothermal sources approaches zero, the NSTE will approach the thermal efficiency of the secondary plant alone.

3.1.2 Incremental Net Secondary Thermal Efficiency (INSTE)

The second metric we use to evaluate the performance of the hybrid plant is the Incremental Net Secondary Efficiency (INSTE). The INSTE is the difference between hybrid plant net power and the net power of the geothermal plant alone divided by the thermal input from the secondary energy source. This is different from the NSTE in that it accounts for the power that would have been produced by the geothermal plant alone if the hybrid plant were not used. While the NSTE may be greater than the secondary-only plant efficiency, the net power may still be less than would be produced by both the secondary-only and geothermal-only plants separately. Thus, if the value of the INSTE is greater than the secondary-only NSTE, the hybrid system will produce more power than the secondary-only and the geothermal-only plants combined. The Incremental Net Secondary Thermal Efficiency (INSTE) is defined by

$$\Delta\eta_{th,Sec} = \frac{P_{Net} - P_{Net,Geo}}{Q_{sec}}, \tag{2}$$

where $P_{Net,Geo}$ is the net power output produced by a geothermal plant without secondary heating, operating on the same reservoir.

3.2. Economic Analysis

A hybrid system may produce more power than a geothermal and a secondary-only system working separately; however, the increase in capacity of the hybrid system must be greater than the increased capital costs for the systems in order for the construction of the project to be justified. Thus, the capital cost ($/kW) of the hybrid system must be considered.

The total capital cost of a hybrid plant is the sum of the equipment costs, well drilling costs, and development costs. The financial model used in Bielicki et al. (in preparation)[†] is used to determine the total capital costs of the hybrid power plant and is compared with the costs of individual power plants. Surface pipeline costs are negligible compared to plant, drilling, and development costs, and are thus not considered here. The capital costs are described in detail next.

a) <u>Equipment Costs:</u>
The surface equipment costs are calculated based on brine geothermal power plant estimates from GETEM

[†] Bielicki, J.M., et al., *Engineering Cost-Competitive Geothermal Electricity from Geologic CO_2 storage, in preparation.,* 2016.

(Geothermal Electricity Technology Evaluation Model) [12]. So in order to obtain costs for CO_2-based geothermal systems, the costs are multiplied by three to account for high-pressure CO_2 and it is assumed that only a single unit is considered for all the equipment for hybrid and individual power plants.

The equations used for different equipments are given as follows:

$$Turbine(\$/kW) = 3 * exp\{4.831 + 0.0127 * min[MW,10] - 0.00394 * T - 0.329 * ln[min(MW,10)] + 0.442 * ln(T)\}, \quad (3)$$

where MW is the nameplate power generation capacity of the turbine in MW, and T is the temperature of the working fluid (°C) flowing into the turbine-generator.

$$Heat\ Exchanger\ (\$/kW) = 3 * 160.06 * exp(-0.066 * LMTD), \quad (4)$$

where LMTD is the logarithmic mean temperature difference across the heat exchanger.
The costs of the cooling and condensing towers are estimated using the ratio of parasitic load to heat rejection, λ, i.e.,

$$\begin{aligned} &Cooling\ Tower\ (\$/kW) = 3 * 7450 * \lambda_{cool} \\ &\lambda_{cool} = 0.137/T_{app} - 0.0012 * T_{Range} \end{aligned} \quad (5)$$

$$\begin{aligned} &Condensing\ Tower\ (\$/kW) = 3 * 3774.3 * \lambda_{condenser} \\ &\lambda_{condenser} = (0.2676 - 0.0049 * T_{amb}) / T_{app} \end{aligned} \quad (6)$$

where T_{app} is the approach temperature, T_{Range} is the difference between the entrance and exit temperatures of the fluid, and T_{amb} is the ambient temperature.

The model assumes a 90%-efficiency pump, and a cost of 3*650 \$/kW is considered based on the quotation for a Flowserve 8x15DMXD-A 3 stage pump.

b) Well drilling Costs:

The well drilling costs are also extracted from GETEM [12] data for 0.33m-diameter wells and are augmented based on the estimates from the U.S. EPA costs for geologic CO_2 storage. The horizontal production well cost is considered to be 1.5 times the vertical wells [13].

Table 3 Well costs with depth.

Depth (km)	Injection well Cost ($M)	Production well Cost ($M)	Total well Cost ($M)
2.5	5.02	7.53	12.55
3.5	9.41	14.12	23.53
4.5	11.66	17.49	29.15

c) Development Costs

A CO_2-geothermal power plant is considered to be developed at a new site (i.e., a “Greenfield”) where there is no initial CO_2 storage. Therefore, the development costs involve site characterization and acquisition, injection and production well permitting and construction, CO_2 transport, injection monitoring, control equipment, site closure, and long-term monitoring. The costs are calculated based on U.S. EPA [14] cost estimates for CO_2-storage projects and the values are listed in Table 4.

Table 4. Geothermal power plant development costs.

Item	Cost	Unit
Site characterization, acquisition	512,505	$/site
Site analysis, research, monitoring	202,000	$\$/mi^2$
Injection well construction	216,500	$/well
Production well construction	324750	$/well
Injection well monitoring	80,692	$/well
CO_2 cost	0.086	$\$/tCO_2$
Control Equipment cost	$520(tCO_2/d)^{0.6}$	$/well head

Monitoring costs	283,200	$

4. Results and Discussion

4.1. Thermodynamic Analysis

The net secondary thermal efficiency (Eq. 1) and incremental net secondary thermal efficiency (Eq. 2) of the hybrid system with varying waste-heat recovery stream temperature and geothermally heated fluid from different reservoir depths, resulting in increasing geothermal-fluid temperatures with increasing reservoir depth, are shown in Fig. 2.

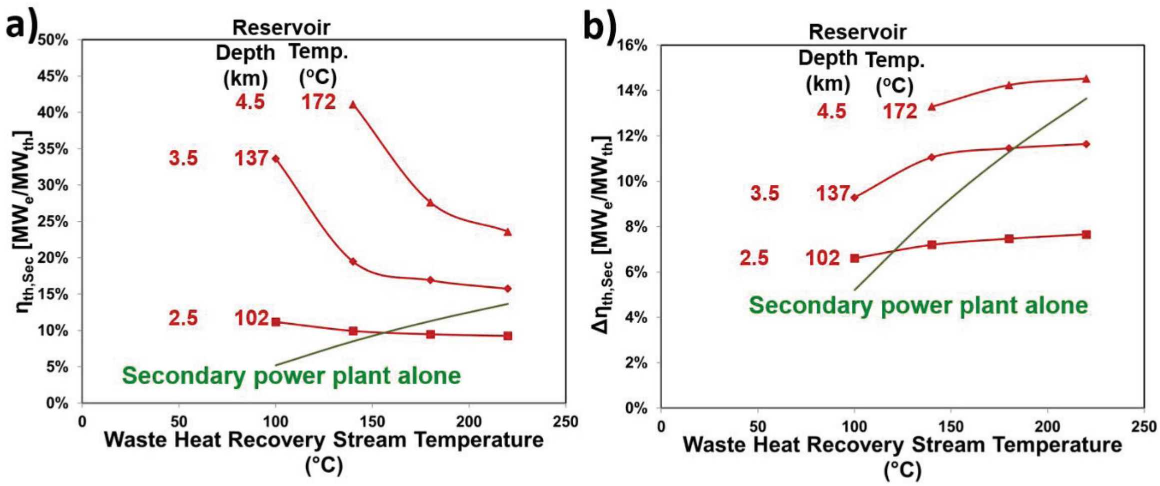

Fig. 2. (a) Net secondary thermal efficiency; (b) incremental net secondary thermal efficiency of the hybrid direct CO_2 (red lines) power plant, compared with the secondary power plant operated alone (solid green line) at geothermal reservoir depths of 2.5 km, 3.5 km, and 4.5 km. Reservoir temperature increases with depth according to a standard continental-crust geothermal gradient of 35°C/km.

The secondary thermal efficiency (Fig. 2a), decreased with an increase in waste heat recovery stream temperature and an increase in geothermal reservoir depth, and in proportion to the geothermal energy fraction. At shallow depth (2.5 km) and high turbine inlet temperatures (>150°C), the secondary efficiency of the hybrid power plant is lower than the secondary power plant alone. In these rare cases, where the NSTE is lower than the secondary plant alone, the turbine exit temperature at State 6 is higher than the temperature at State 4, resulting in a net heat flow into the reservoir. Thus, the system would not be operated under these conditions.

In Fig. 3, we compare the total net power produced by hybrid geothermal power plants with the sum of the power produced by the individual power plants, operating alone using the Incremental Net Secondary Thermal Efficiency (INSTE). When the INSTE of a given hybrid system is greater than that of the secondary power plant alone, more net power is generated through the combination of the geothermal and secondary systems than if the systems were operated separately. At relatively shallow reservoir depths (2.5 km, 3.5 km) and high waste heat recovery stream temperatures (>100°C and >180°C, respectively) the sum of the power produced from individual power plants is higher than the power produced from the hybrid power plant. Therefore, at low-temperature secondary energy resources, the direct CO_2 hybrid power plant can produce more net power than the sum of the power produced by individual power plants.

The incremental thermal efficiency (Fig. 2b) is often higher than the secondary-only power plant thermal efficiency; however, at shallow depths and high waste-heat temperatures, the hybrid system has a lower thermal efficiency than a secondary plant alone, so that the hybrid plant should not be operated. In a secondary-only power plant, the high-side working fluid pressure can be selected to maximize the system output power. However, for the direct CO_2 systems we utilize here, the pressure and density of the fluid entering into the turbine is determined by the system operating conditions. Thus, the hybrid plant is constrained by the reservoir conditions and is better-suited to produce power at lower waste-heat recovery stream temperatures.

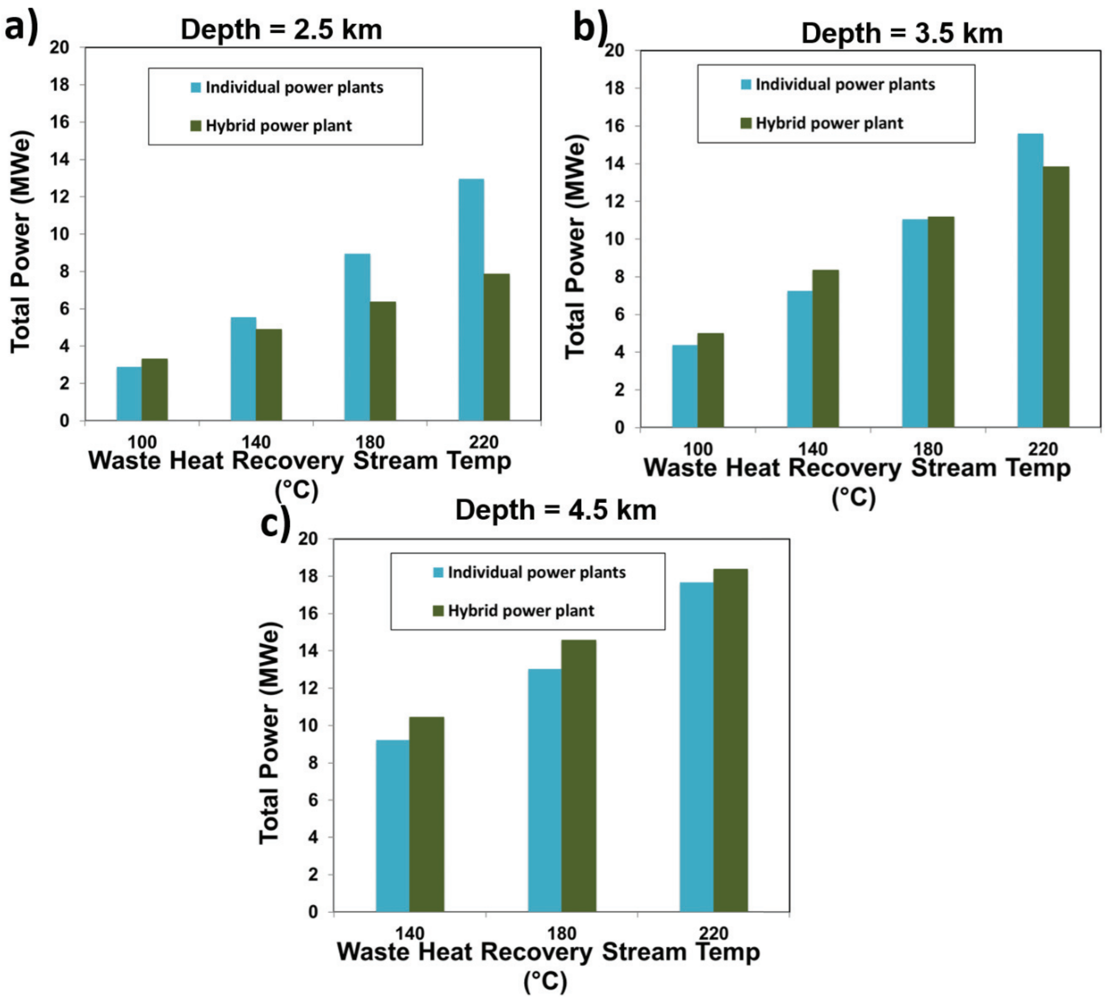

Fig. 3.Total electric power produced by the hybrid power plant and the stand-alone power plants for different waste heat recovery temperatures and geothermal reservoirs, located at depths of (a) 2.5 km, (b) 3.5 km, and (c) 4.5 km. Reservoir temperature increases with depth according to a standard continental-crust geothermal gradient of 35ºC/km.

4.2. Economic Analysis

Total capital costs (well drilling cost + development cost + surface power plant cost) in Fig. 4 and the capital cost per power generating capacity ($/kW) in Fig. 5 of the hybrid system are compared with individual power plants. At deeper depths (3.5 km and 4.5 km) the total capital costs and cost per unit electricity for hybrid power plants is lower than the sum of the costs of the individual power plants. However, at shallow depth (2.5 km) and with high-grade secondary resource temperatures (180°C and 220°C) the capital cost per unit electricity for hybrid power plants is higher than the sum of the costs of the individual power plants. Therefore, direct CO_2 hybrid power plants can be both efficient and economic when a low-grade secondary heat resource is used for auxiliary heating of the geothermally preheated fluid. At deeper depths (3.5 km, 4.5 km) and low-grade secondary resource temperatures (100°C, and 140°C, respectively), though the secondary power plant alone has lower capital costs than the geothermal power plant, the power generating capacity of the secondary power plant is also lower than that of the geothermal plant and, hence, the cost per electricity generated for the secondary plant is higher than that of the geothermal plant.

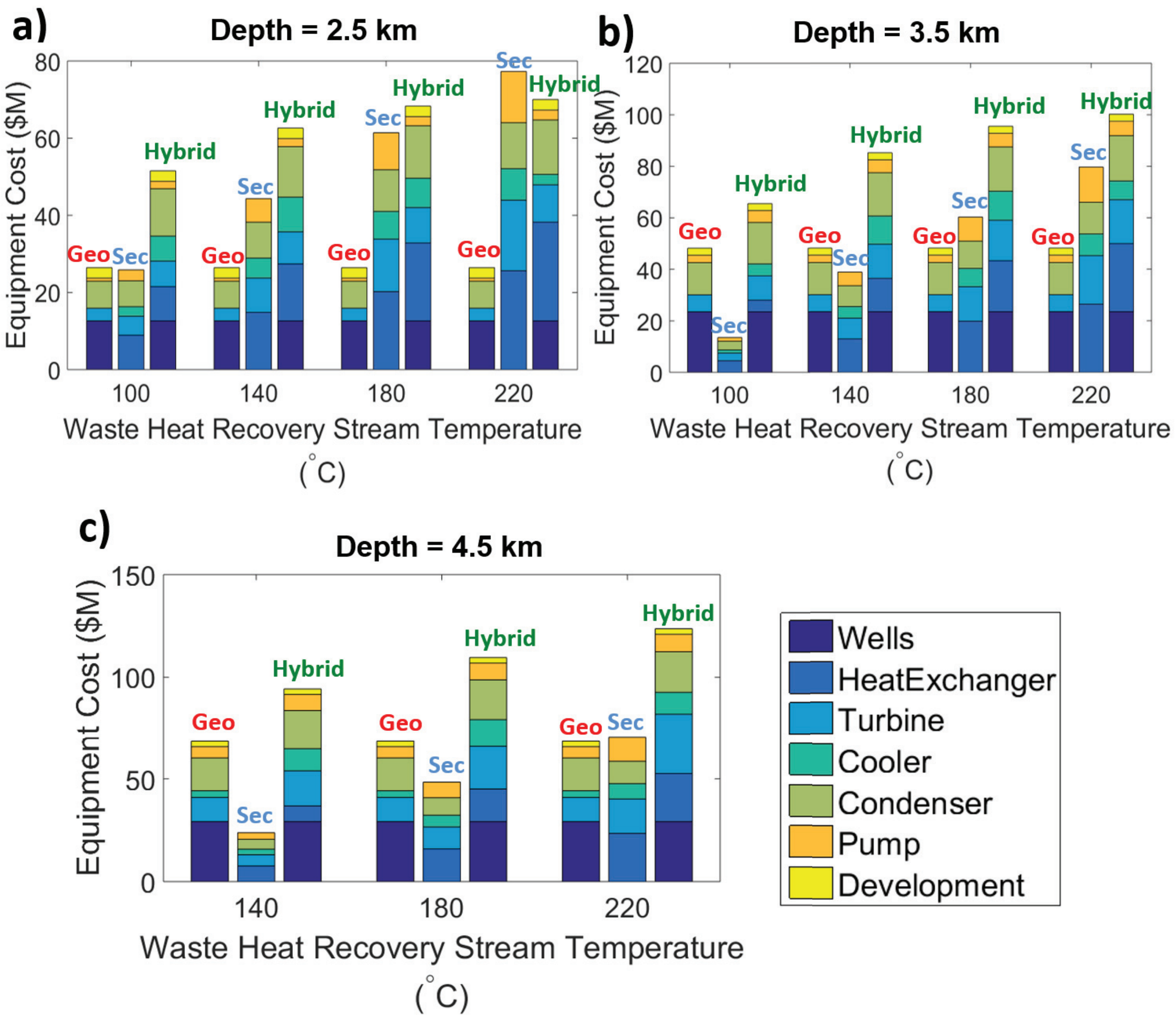

Figure 4 Capital costs for the hybrid power plant and stand-alone power plants (Geo=Geothermal, Sec=Secondary) for different waste heat recovery temperatures and geothermal reservoirs, located at depths of (a) 2.5 km, (b) 3.5 km, and (c) 4.5 km. Reservoir temperature increases with depth according to a standard continental-crust geothermal gradient of 35ºC/km.

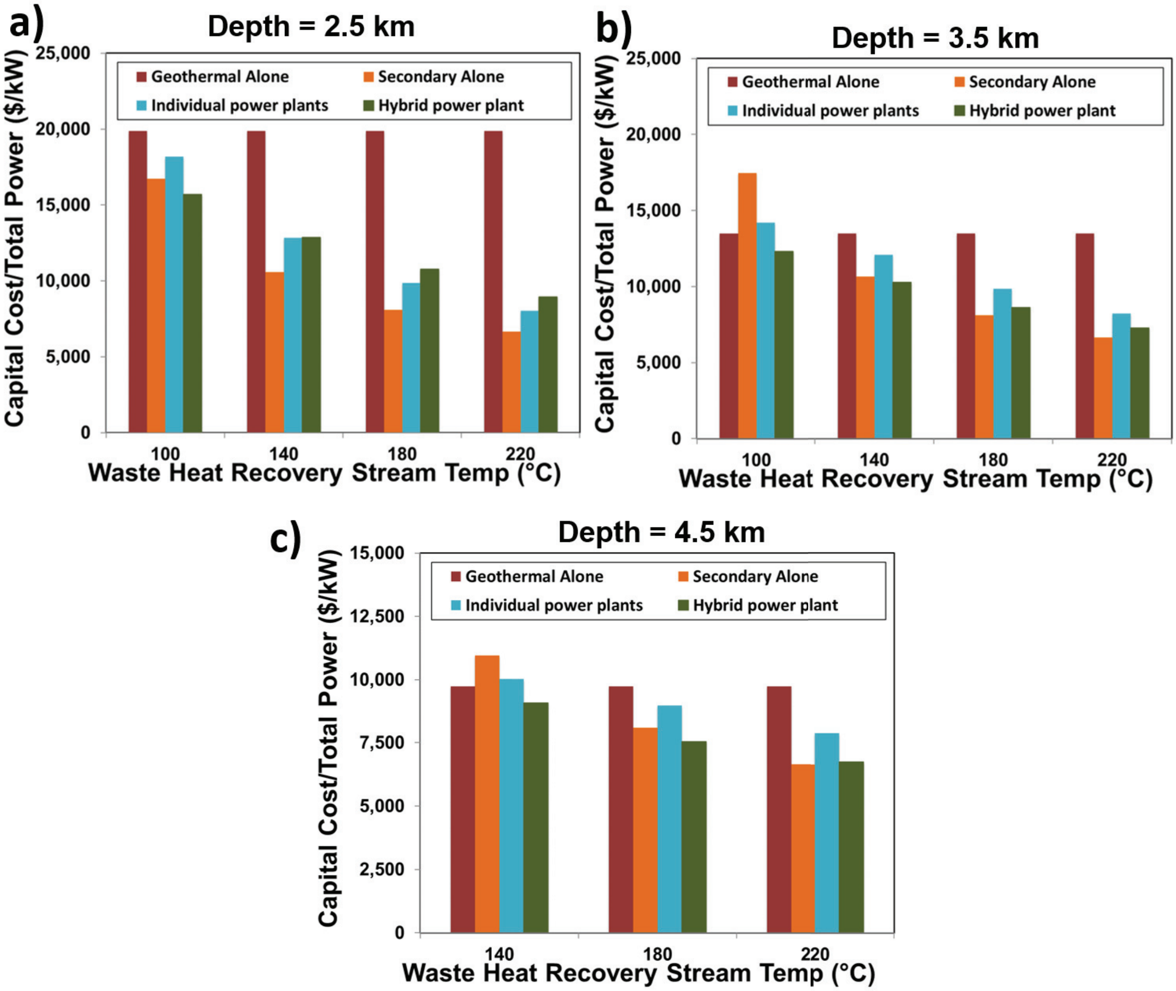

Fig. 5. Total capital cost per unit of electricity produced for the hybrid power plant, for separate, stand-alone power plants, and for the sum of stand-alone (individual) power plants for different waste-heat recovery temperatures and geothermal reservoirs, located at depths of (a) 2.5 km, (b) 3.5 km, and (c) 4.5 km. Reservoir temperature increases with depth according to a standard continental-crust geothermal gradient of 35ºC/km.

5. Conclusions

We studied the thermodynamic and energy conversion performance as well as the capital costs of hybrid CO_2-plume geothermal power plants, i.e., power plants, where geothermally preheated CO_2 is auxiliary heated by a secondary (waste-heat) energy source. The results are compared to operating separate, stand-alone plants that use the same geothermal and secondary energy resources. Combining the equipment into a hybrid power plant results in both favorable thermodynamic performance and lower capital costs per unit electricity produced, compared to producing the power individually in secondary-only and geothermal-only power plants for all waste heat temperatures studied at geothermal reservoir depths of 2.5 km, 3.5 km, and 4.5 km and a standard continental-crust geothermal gradient of 35°C/km. This study focused on the performance analysis of direct CO_2-Plume Geothermal (CPG) power plants presented in Adams et al. (2015). Additional research may further improve power plant design to optimize the performance and economics of the hybrid system, for example for high-grade secondary heat resources that are combined with higher-temperature geothermal energy resources. The study here focused on low-grade geothermal resources as those are more common worldwide and, in particular, in Switzerland.

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Disclaimer

Drs. Randolph and Saar have significant financial and business interests in TerraCOH Inc., a company that may commercially benefit from the results of this research. The University of Minnesota has the right to receive royalty income under the terms of a license agreement with TerraCOH Inc. These relationships have been reviewed and managed by the University of Minnesota in accordance with its conflict of interest policies.

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