8 **Brine displacement by CO₂, energy extraction rates, and lifespan of a CO₂-limited**
9 **CO₂ Plume Geothermal (CPG) system with a horizontal production well**
10

11 Nagasree Garapati¹, Jimmy B. Randolph^{1,2} and Martin O. Saar^{1,2,3}

12 ¹Department of Earth Sciences,

13 University of Minnesota – Twin Cities,

14 310 Pillsbury Dr. SE

15 Minneapolis, MN 55455, USA

16 ²TerraCOH Inc.

17 1409 Washington Ave N,

18 Minneapolis, MN 55455, USA.

19 ³Geothermal Energy and Geofluids Group,

20 Institute of Geophysics, Department of Earth Sciences,

21 ETH-Zürich, Sonneggstr. 5, 8092 Zürich, CH

22 Corresponding E-mail: ngarapat@umn.edu, Tel: +1-612-625-3928, Fax: +1-612-625-3819

23

24 **Abstract**

25 Several studies suggest that CO₂-based geothermal energy systems may be operated
26 economically when added to ongoing geologic CO₂ sequestration. Alternatively, we demonstrate
27 here that CO₂-Plume Geothermal (CPG) systems may be operated long-term with a finite amount
28 of CO₂. We analyze the performance of such CO₂-limited CPG systems as a function of various
29 geologic and operational parameters. We find that the amount of CO₂ required increases with
30 reservoir depth, permeability, and well spacing and decreases with larger geothermal gradients.
31 Furthermore, the onset of reservoir heat depletion decreases for increasing geothermal gradients
32 and for both particularly shallow and deep reservoirs.

33

34 **Keywords:** carbon dioxide; geothermal systems; reservoir simulations; brine displacement;
35 carbon capture and sequestration (CCS); carbon capture utilization and sequestration (CCUS),
36 energy extraction rates, CO₂ geothermal.

37

37

38 **Introduction**

39 Carbon dioxide (CO₂) capture and sequestration (CCS) in deep saline aquifers has been widely
40 considered to reduce CO₂ emissions to the atmosphere (Metz *et al.*, 2005; IPCC, 2007; 2014).
41 Additionally, several previous studies (Brown, 2000; 2003; Fouillac *et al.*, 2004; Pruess, 2006;
42 2007; 2008; Atrens *et al.*, 2009) have considered utilizing CO₂ as a geothermal working fluid, in
43 the context of an Enhanced Geothermal System (EGS). Operating an EGS typically involves
44 hydraulically, thermally, and/or chemically stimulating naturally low-permeability rock to
45 increase the bulk formation permeability, a process that has a significant likelihood of inducing
46 seismicity (e.g., Evans *et al.*, 2005; Majer *et al.*, 2007; Giardini, 2009). In contrast, CO₂ Plume
47 Geothermal systems (CPG) (Randolph and Saar, 2011a, b; Saar *et al.*, 2012-2015; Buscheck *et*
48 *al.*, 2013), involve injection of CO₂ that comes from a CO₂ emitter, as a subsurface working fluid
49 to extract heat and pressure energy (enthalpy) from naturally high-permeability sedimentary or
50 stratigraphic basins. Formations in these basins are typically bounded by low-permeability
51 formations such as base rocks and caprocks, although more complex trapping structures may
52 exist. The injected CO₂ forms a large subsurface CO₂ plume that permanently sequesters CO₂
53 underground and absorbs heat from the geothermal reservoir. The CO₂ plume can be “tapped”
54 for thermal and/or electric power production in a geothermal power system (Randolph and Saar,
55 2011a, b; Saar *et al.*, 2012-2015; Adams *et al.*, 2014; 2015) as illustrated in Figure 1. The heat
56 density of sedimentary basins that do not lie in tectonically or volcanologically active regions, or
57 that are not affected by advective heat transfer due to significant groundwater flow, is typically
58 relatively low (Saar, 2011). However, this drawback can be counteracted by the large accessible
59 volume of natural reservoirs compared to the artificial, and thus relatively small, reservoirs

(Dezayes *et al.*, 2005) developed by hydro-fracturing or hydro-shearing crystalline basement rock. Furthermore, supercritical CO₂ has a high mobility (i.e., low kinematic viscosity) and high thermal expansibility compared to water, resulting in the formation of a strong thermosiphon, a physical effect which circulates a fluid without the necessity of a mechanical pump (Atrens *et al.*, 2009; 2010; Adams *et al.*, 2014). This thermosiphon eliminates the need for parasitic pumping power requirements, other than for the pumps that inject the CO₂ coming from a CO₂ emitter, which is not part of the geothermal power cycle (Figure 1). These injection pumps are only required initially in the CO₂-limited CPG systems (discussed here) during the CO₂ plume formation stage. The thermosiphon effect significantly increases the electric power production efficiency of the geothermal system compared to water-based geothermal systems, thereby more than compensating for the low heat capacity of supercritical CO₂, compared to water (Adams *et al.*, 2014). The produced power can then, for example, be used to drive the CO₂ injection pumps, if geologic CO₂ sequestration is ongoing, i.e., during a CCS project, to reduce or eliminate the costs of adding CCS operations to fossil-fuel power plants (Randolph and Saar, 2011a) and/or the power could be supplied to the electric grid (Randolph and Saar, 2011b). Because the produced CO₂ is reinjected into the geothermal reservoir with the main CO₂ sequestration stream, coming from the CO₂ emitter, all of the CO₂ is ultimately geologically sequestered resulting in a CO₂ sequestering geothermal power plant with a negative carbon footprint (Randolph and Saar, 2011b; Saar *et al.*, 2012-2015) a Carbon Capture Utilization and Sequestration (CCUS) operation. In contrast, with CO₂-based EGS, the amount of permanently sequestered CO₂ is significantly limited as reservoirs that are artificially created during EGS are comparatively small (e.g., reservoirs in the Williston Basin, U.S., extend hundreds of kilometers (Steadman *et al.*, 2006), whereas the EGS site in Soultz, France, has an extent of a few hundred

meters (Dezayes *et al.*, 2005)). Therefore, CPG systems tend to exhibit significantly higher heat extraction and power generation performances and much larger CO₂ sequestration potentials than CO₂-based EGS (Randolph and Saar, 2010; Randolph and Saar, 2011a, b; Saar *et al.*, 2012-2015; Adams *et al.*, 2014; 2015).

Alternatively, when geologic CO₂ storage is uneconomic, CPG systems could be operated with a limited, finite amount of CO₂ initially stored underground and thereafter run with little or no additional makeup CO₂ (Figure 1). Here, we investigate displacement of the brine (by the supercritical CO₂) as well as heat energy extraction characteristics, related reservoir heat depletion rates, and associated reservoir lifespans of such CO₂-limited CPG systems. The lifespan of the geothermal power plant can be increased by operating the CPG system in such a way that it depletes the geothermal reservoir heat more slowly. Furthermore, the CPG system should be operated with an optimum spacing between the injection and production wells and with an optimum CO₂ injection and circulation rate both to deplete the reservoir heat slowly and to reduce or eliminate brine-CO₂ interface up-coning and related water in the produced fluid. Here, we aim for a target minimum CO₂ concentration in the produced fluid of approximately 94%, which is based on suggestions by Welch and Boyle (2009) for CO₂-based power generation equipment.

The primary focus of this paper is to study energy extraction rates from geothermal reservoirs when CO₂-limited CPG systems are employed as a function of various geologic (reservoir depth, permeability, and temperature) and operational (well spacing and CO₂ circulation rate) parameters. Energy conversion (enthalpy to electricity) technologies are considered elsewhere (Adams *et al.*, 2014; 2015) for a 5-spot well CPG system. However the overall (i.e., combined heat and pressure) energy (i.e., enthalpy) loss in the production well is minimal in a *direct* CPG

system (Adams *et al.*, 2014) as some of the heat energy is converted to pressure energy (Figure 2) by Joule-Thompson cooling, which is the primary form of energy converted to electric power in the turbine (an expansion system) and associated generator. Furthermore, Randolph *et al.* (2012) show that in a CPG system, heat transfer in the production well is nearly adiabatic within a few days (~5 days) after the onset of fluid production and that, as a result, adiabatic heat transfer can be assumed in the production well. Analogous considerations apply to the injection well.

Here, we employ a numerical, axisymmetric model (that also approximates a system with a skewed CO₂ plume as shown in Appendix A) that is formulated in cylindrical coordinates, representing a reservoir initially filled with native brine that is gradually displaced by the injected, supercritical CO₂ (Figures 1 and 3). The CO₂ enters the reservoir through a vertical, injection well. After moving through the geothermal reservoir, the heated CO₂ is produced from a horizontal, circular^[NG1] production well (Noble, 1992; Gardes, 1995; 1998), where production well configurations other than circular (e.g., half-circular, parabolic, or linear) may also be considered as discussed below and in Appendix A. We characterize the performance of such a CPG system as a function of heat energy output from the reservoir, reservoir lifespan or longevity, given as reservoir temperature decline over time, and up-coning of the brine-CO₂ interface into the inlet of the production well, reported as CO₂ fraction in the produced fluid at the surface, which is elevated from the CO₂ fraction in the reservoir close to the production well, as discussed below.

Conceptual and Numerical Model:

In keeping with the objective of formulating a simple model to gain first-order insights, we assume a homogeneous reservoir with a symmetrical CO₂ plume, formed around the vertical

injection well (Figure 1a). In actual systems, the CO₂ plume would likely be skewed opposite the dip direction of the reservoir-caprock interface (Figure 3). Skewing of the CO₂ plume due to an underlying groundwater flow field does not have a significant effect on the simulations (not shown) as typical CO₂ injection rates are substantially larger than typical groundwater flow rates. In contrast, a dipping reservoir-caprock interface more likely imposes a preferred CO₂-plume spreading direction (i.e., skewing of the CO₂ plume) so that a half-circular, parabolic, or linear horizontal production well would likely be installed, rather than a circular well, directly underneath the caprock to capture the geothermally heated CO₂ in the reservoir. However, as shown in Appendix A, the results of this numerical study are minimally affected by details of whether the CO₂ plume is symmetrically distributed around the injection well or skewed, as long as the subsurface CO₂ sweep volume for the symmetric and the skewed CO₂ plume systems are comparable. Therefore, a three-dimensional (3D), axisymmetric system is formulated as the radial symmetry reduces computational effort to that of a two-dimensional (2D) system (Figure 3).

The simple geothermal reservoir considered here has a porosity of 10%, is 50 m thick[NG2], is located at an average depth of 2.5 km, is heated from below assuming a geothermal gradient of 34 °C/km, the approximate continental average (Pollack *et al.*, 1993), and is bounded by

horizontal, impermeable bedrock and caprock formations as an approximation of a stratified or broad dome-shaped reservoir, as illustrated in Figure 1. Other, more complex, trapping structures may be considered, however, this simple conceptual model should suffice to provide first-order

insights. Furthermore, the integrity of the reservoir and bounding structures is assumed to remain intact throughout the simulations. Questions regarding fluid-mineral reactions and associated bedrock/caprock integrity alterations are beyond the scope of the current study but have been addressed elsewhere by our group (e.g., Kong et al., 2013; Luhmann et al., 2013; 2014; Tutolo et al., 2014a, b, c; 2015a, b). While the overall dimensions of the reservoir considered here are kept conservatively small to illustrate the performance of a moderately scaled system, larger stratigraphic or sedimentary basin reservoirs, such as in the Williston Basin, North Dakota, or the off-shore Sleipner Field, Norway, exist worldwide and may potentially be used for CPG. Nonetheless, despite the moderate size of the geothermal systems simulated to date, the performance of CPG systems tends to outperform significantly that of EGS with respect to power production and reservoir lifespan even when CO₂ is used, instead of water, as the subsurface heat extraction fluid in EGS simulations (Randolph and Saar, 2011b; Adams et al., 2014; 2015). This is due to the more effective and widespread advective heat transfer occurring in naturally porous and permeable sedimentary basin reservoirs, utilized in CPG systems, compared to the often widely spaced fracture networks utilized by EGS (Randolph and Saar, 2011b).

Initially the reservoir is assumed to be filled with native brine with an NaCl saturation of 20%. During simulation, the brine is gradually displaced by the injected supercritical CO₂. The production well (Noble, 1992; Gardes, 1995; 1998) is located directly below the caprock (Figures 1a and 3). The numerical reservoir simulator employed is TOUGH2 (Pruess *et al.*, 1999; Pruess, 2004) with the equation of state (EOS) modules ECO2N (Pruess, 2005) and ECO2H (Spycher and Pruess, 2011), for reservoir temperatures at/below and above $T=100^{\circ}\text{C}$, respectively. Numerical model parameters are listed in Table 1. During brine displacement by the CO₂, water is permitted to dissolve into the CO₂ and CO₂ can dissolve into the water. As

dissolution occurs at the brine-CO₂ interface, the dissolution minimally affects CO₂ circulation on the timescale considered in the present analysis. Table 1 lists more details about the model setup including the use of a standard semi-analytic conductive heat exchange boundary condition to over- and underlying layers (Pruess *et al.*, 1999).

Fluid extraction at the production well, with a constant bottom-hole pressure, does not work well for this reservoir configuration and multicomponent system. Randolph and Saar (2011b) used production-against bottom-hole pressure, as it allows a fixed pressure difference between wells. However, if this approach is employed in the present analysis, CO₂ production flow rates are extremely high (up to ~1000 kg/sec in the 5×10^{-14} m² permeability case with 40 bar pressure difference between wells) for the first few days after the onset of production while the system bleeds off excess pressure. Thereafter, production flow rates gradually reduce to a value in the tens of kg/sec within a month. For long durations (tens of years), rates will slowly increase to 80 to 100 kg/sec, as the CO₂ mass fraction in the produced fluid increases. In this scenario, the amount of fluid produced and circulated is not the same. Because of this behavior, and to simulate the case of recirculating the produced fluid back into the reservoir, it is more appropriate to model the system with fixed flow rates rather than a fixed pore-fluid pressure differential between the injection and the production wells. The flow rates can be fixed by throttling the circulation rate at the turbine (and in some cases an additional valve) to optimize power production, maintain sufficient circulation, and maximize reservoir life span (Adams *et al.*, 2014).

Finally, in contrast to our previous investigations (Randolph and Saar, 2011a, b; Adams *et al.*, 2014; 2015), in this study the CPG system is operated in two stages. During the first stage, CO₂ injection into the reservoir and brine displacement develops the CO₂ plume. During the second

stage, the geothermally heated CO₂ is produced and circulated to generate power. Thereafter, the cold CO₂ is reinjected into the reservoir closing the power loop. In base-case simulations, the CO₂ plume is built over 2.5 years with a total injected CO₂ mass of 2 Mtonnes, which is injected at a rate increasing linearly from 0 to 1 Mtonnes/year over the first year, and then at a constant rate of 1 Mtonne/year for an additional 1.5 years. Once the CO₂ plume is built, new CO₂ injection is stopped (in the base-case simulations) and fluid (mostly CO₂) production and circulation of pure CO₂ (produced CO₂ and makeup CO₂ for the small amount of produced brine) is initiated. Any produced brine is removed before the cooled CO₂ is reinjected into the reservoir. Separated brine may be reinjected into the formation away from the CO₂ plume, providing an additional means of controlling and directing the CO₂ plume pressure field and flow direction (Buscheck *et al.*, 2014) and avoiding the need to treat and dispose of the brine near the land surface. If instead the produced fluid is injected without removal of the residual brine, the brine accumulates around the injection well due to its lower mobility compared to CO₂, pressurizing the reservoir around the injection well (Appendix B). Such increases in pore-fluid pressure are of significant concern as, besides reducing the injectivity of the well, they can lead to deformation, fracturing, and shearing of the formation as well as (micro) seismicity and possibly CO₂ leakage to the surface. After the injection phase, the circulation rate is increased linearly over 2 years, and then maintained at a constant rate for an additional 98 years as shown for the first 7.5 years in Figure 4. In all figures, time is set to zero at the beginning of CO₂ production and circulation. Table 2 lists the geologic conditions for the base-case reservoir model. Reservoir fluid parameters are listed in Table 3. Randolph and Saar (2011b) provide further explanations for the choice of specific base-case reservoir parameters. In addition to the base case, the following simulations are performed, where a mean annual surface temperature of 15°C is used:

- i) *Well spacing*: The spacing between the vertical injection well and the horizontal, circular production well is varied over distances of 500 m, 707 m, and 1000 m.
- ii) *Depth*: Three reservoirs are considered at depths of 1.5 km, 2.5 km, and 3.5 km and temperatures of 66°C, 100°C, and 134°C, respectively, assuming a geothermal gradient of 34 °C/km, the approximate continental average (Pollack et al., 1993).
- iii) *Geothermal gradient*: Three reservoir models with geothermal gradients of 20°C/km, 34°C/km, and 50°C/km are employed, resulting in reservoir temperatures, at a depth of 2.5 km, of 65°C, 100°C, and 140°C, respectively.
- iv) *Permeability*: Six reservoir models are considered with horizontal permeabilities in the range of $2 \times 10^{-14} \leq k_x \leq 10 \times 10^{-14} \text{ m}^2$ and a constant horizontal, k_x , to vertical, k_z , permeability anisotropy of $k_x = 2k_z$ as may be expected for sedimentary basins.
- v) *Circulation Rate*: Simulations are conducted for base case models with fluid production and circulation rates of 4 Mtonnes/year, 5 Mtonnes/year, and 6 Mtonnes/year).

Other parameters are the same as in the base-case model (Tables 1 and 2).

Results and Discussion

As stated, we explicitly simulate brine displacement and formation of the supercritical CO₂ plume by injection of CO₂ into the initially brine-filled geothermal reservoir. Thus, simulations commence with a CO₂ injection phase which is followed by a CO₂ production, circulation, and reinjection phase (Figure 4). During the circulation phase, no further CO₂ is injected (makeup

CO₂ is added for the produced and removed brine) in base case simulations. However, in cases where CO₂ injection tapers off while CO₂ circulation is ramped up, the CO₂ up-coning effect decreases and the total amount of CO₂ required increases, as shown in Garapati *et al.* (2014). However, in keeping with our conservative objective of determining the minimum amount of CO₂ required for CPG system performance, only simulations of the non-ideal former approach, where CO₂ injection is halted before fluid production and circulation commences, are considered. The purpose of terminating further CO₂ injection when fluid production and circulation begins, as would be common practice when CPG is added to an ongoing geologic CO₂ sequestration site, is to illustrate the performance of a CPG system without continued CO₂ supply for situations when only a minimal amount of CO₂ is available or when CO₂ is too expensive.

The performance of the system is analyzed based on: 1) the reservoir's thermal energy extraction rate; 2) percentage of reservoir heat depletion over 20 years; and 3) approximate minimum CO₂ mass fraction of 94% in the produced fluid. Achieving the latter objective likely reduces power system problems, as Welch and Boyle (2009) concluded that the CO₂ to total (CO₂ + water) mass fraction in the produced fluid should be at least approximately 94% for the power conversion technologies they investigated (specialized turbines that can handle up to about 6% free-phase water). Other energy conversion systems, with different specifications, may be employed as well, however, a minimum CO₂ mass fraction of 94% serves as a useful target value to gain first-order insights into the effects of reservoir and system parameters on CO₂-water interface up-coning into the production well and resultant implications on power conversion performance. Due to the approximate, first-order nature of this target value, we consider CO₂ mass fractions in the produced fluid slightly below 94% as being still sufficient.

A 20-year time span for evaluation of reservoir heat depletion is assumed as this duration may serve as a minimum life span of a power plant from an economic and investment point of view. Furthermore, heat depletion trends over this time span enable extrapolation of results beyond 20 years, while the focus of figures on the first 20 years allows better display of this initial, critical performance stage of the system. In actuality, power plant life spans are expected to be significantly longer than 20 years, i.e., 40 years and more, and, in fact, our simulations are run for 100 years. The following sections report results for specific geologic and operational parameters.

CO₂ plume formation and well spacing

During the initial brine displacement and CO₂ plume formation period, the distance the CO₂ migrates away from the injection well depends on the amount of CO₂ injected. The spacing between the vertical injection well and the horizontal, circular production well has to take this CO₂ migration distance into account to minimize up-coning of the brine-CO₂ interface into the production well. Figure 5 shows the CO₂ saturation fraction in the reservoir pore fluid, with respect to water, after 2.5 years of CO₂ injection for CO₂ plume development, before fluid production and circulation commences. When 2 Mtonnes of CO₂ are injected, the CO₂ migrates up to ~800 m from the injection well at the top of the reservoir as shown in Figure 5a. When 4 Mtonnes of CO₂ are injected, the CO₂ migrates beyond 1000 m from the injection well as seen in Figure 5b. It is important to note that the contours shown in Figure 5 reflect the CO₂ saturation in the reservoir and not within the production well. Due to the significantly higher mobility (inverse kinematic viscosity) of CO₂, compared to brine, the CO₂ concentration in the produced fluid (reported in subsequent figures) will be significantly higher than in the reservoir directly adjacent to the production well inlet.

For a total injected CO₂ mass of 2 Mtonnes the CO₂ mass fraction in the produced fluid versus time for different well spacings is shown in Figure 6a. When the well spacing is small, brine upconing into the production well is at a minimum. Conversely, when the production well is located beyond the CO₂ migration distance, only brine is produced until CO₂ circulation is fully developed. However, with increasing well spacing, heat sweeping occurs over a larger reservoir volume and, hence, thermal depletion of the reservoir is less pronounced than when injection and production wells are closer to each other, as shown in Figure 6b.

Smaller amounts of injected CO₂ are desirable when only a limited supply of CO₂ is available. Conversely, larger total amounts of injected CO₂ and corresponding greater distances between CO₂ injection and production wells may be of interest, resulting in larger reservoir heat sweep regions, when CO₂ availability is not as much of a concern and when longer periods of geothermal heat energy extraction are more important than an early onset of geothermal energy production or maximizing rates of early heat energy production.

The tradeoff between reservoir longevity on the one hand and early heat energy extraction on the other hand, may be somewhat relaxed either by first installing a production well that is closer to the injection well and later installing a second production well at a greater distance or by first producing brine to generate power and then switching to power conversion equipment that operates on CO₂. Of course, these solutions come at the expense of additional well drilling and installation costs in the first case and additional costs for switching power conversion equipment from brine to CO₂ in the second case. Ultimately, the choice of technology implementation depends on economics, which in turn depends in part on geology, availability of CO₂, proximity of the power grid and markets, as well as public acceptance and policy regulations, to name some.

Reservoir Depth

Three reservoir models are considered, located at average depths of 1.5 km, 2.5 km (base case), and 3.5 km, each with a thickness of 50 m. For this set of simulations, reservoir fluid pressure is hydrostatic. Reservoir temperature is given by a geothermal gradient of 34°C/km (base case), that is undisturbed by groundwater flow (Saar, 2011), and a conservatively high mean annual surface temperature of 15°C. The injection temperature is calculated based on isentropic compression of CO₂ in the injection well (Table 4).

Figure 7a shows the produced CO₂ mass fraction with time. As reservoir depth increases, the upconing of water into the production well inlet increases, leading to a lower CO₂ mass fraction in the produced fluid at the surface. This is caused by the increased solubility of water into the supercritical CO₂ phase with increased pressure and temperature. Therefore, as depth and related temperature increase, the water mass fraction increases, first as water dissolved in CO₂ and later during the rise in the production well to lower pressures as exsolved, free-phase water. This leads to a reduction in the CO₂ mass fraction in the produced fluid with increasing reservoir fluid pressure (and temperature) for the same amount of CO₂ injected (2Mtonnes). The thermal energy extraction rate from the reservoir, given as the product of CO₂ mass flow rate and the change in

CO₂ enthalpy from CO₂ injection to production, is represented in Figure 7b. As the depth increases the initial reservoir heat increases and, therefore, the amount of energy extracted increases. The percentage decrease in the energy extraction rate over 20 years (Figure 7b) is 28% for 1.5 km, 11% for 2.5 km, and 19% for 3.5 km deep reservoirs.

Geothermal Gradient

In order to determine the effects of the geothermal gradient, and the resultant reservoir temperature at a depth of 2.5 km (base case), on the produced CO₂ mass fraction and on heat

energy extraction rates, three different undisturbed (Saar, 2011) geothermal gradients, 20°C/km,

34°C/km (base case), and 50°C/km, are considered, resulting in respective reservoir temperatures

of 65°C, 100°C (base case), and 140°C. All other model parameters are identical to the base case

(Table 1).

Figure 8a shows the amount of CO₂ mass fraction in the produced fluid. An increase in the geothermal gradient (i.e., the reservoir temperature at 2.5 km depth) increases the CO₂ density difference between the injection and production wells, which results in a greater thickness of the CO₂ plume near the production well, reducing the up-coning effect of water into the well. Figure 8b shows that, as expected, the thermal energy extraction rate is higher for higher geothermal gradients, but that this effect is accompanied by a steeper decline in heat energy extraction rate over time. Nonetheless, during heat extraction operation, heat extraction rates are higher for larger geothermal gradients (Figure 8b). For the lowest geothermal gradient (20 °C/km), there is a dip in the heat extraction rate just before Year 2 (Inset in Figure 8b). This dip is caused by the decrease in the enthalpy of the produced fluid due to the presence of a high free-phase water fraction, present at lower fluid temperatures. In contrast, for higher geothermal gradients, this decrease in enthalpy is less due to smaller fraction of free-phase water and is compensated by the increase in the mass flow rate.

Table 5 shows the initial amount of CO₂ required for various scenarios to maintain a CO₂ mass fraction in the produced fluid greater than, or close-to, 94% and the percentage decrease in the heat extraction rate over 20 years at a fluid circulation rate of 4 Mtonnes/Year.

Reservoir Permeability

In order to study the effects of varying reservoir permeabilities on system performance, simulations are performed for horizontal permeabilities, k_x , ranging from 2×10^{-14} m² to 10×10^{-14} m². The vertical permeability, k_z , is adjusted to maintain the same anisotropy ratio of $k_x/k_z=2$, as before, in all scenarios. As the permeability of the reservoir increases, up-coning of CO₂ into the production well increases, as seen in Figure 9a, where the CO₂ mass fraction in the produced fluid is plotted over time. Furthermore, lower reservoir permeabilities initially (i.e., during the

first 12 to 18 years in our simulations) result in lower temperatures of the produced fluid (Figure 9b). After that time, production fluid temperatures are higher for lower-permeability reservoirs because such reservoirs preserve heat longer (Figure 9b).

CO₂ Circulation Rate

While electricity production is not the focus of this contribution and hence not provided in the figures, the relationship between electricity production and both reservoir heat energy extraction and reservoir heat (or temperature) depletion rates, justify a brief discussion of the involved dependencies. CPG and other CO₂-based geothermal systems (e.g., CO₂-based EGS) typically develop a vigorous thermosiphon (Atrens *et al.*, 2009; 2010; Adams *et al.*, 2014) that drives CO₂ circulation through the reservoir, the wells, and the power conversion equipment at the surface, including the turbine. The electric power output from the turbine, coupled with a generator, in a CPG system depends on both the thermosiphon-generated CO₂ mass flow rate through the turbine and the temperature-dependent CO₂ density gradient across the turbine, with the former being significantly more dominant (Adams *et al.*, 2014; 2015). While using the thermosiphon to drive the CO₂ circulation of the geothermal power cycle reduces, or possibly eliminates, parasitic pumping power requirements, this portion of the geothermal energy cannot additionally be converted to electricity. Thus, partitioning geothermal energy utilization between maintaining a sufficiently high CO₂ mass flow rate and spinning the turbine is subject to optimization for maximum electric power production (Adams *et al.*, 2015). Both uses of the thermosiphon, i.e., to maintain CO₂ mass flow rates and to drive the turbine, deplete the reservoir heat energy. It is possible, however, to throttle the thermosiphon effect, reducing power production, but extending reservoir longevity. Thus, a careful balance must be found that maintains a produced fluid flow rate while allowing cost-competitive electricity generation, and maximizing reservoir lifespan

through reduced heat depletion. Electricity markets, prices, and other economic considerations also affect optimal operation of a CPG (or CO₂-based EGS) system.

Table 6 provides optimized circulation rates for different well spacings with a 10% decrease in the thermal heat extraction rate over 20 years. Figure 10a shows heat energy extraction rates from the reservoir versus time after the onset of CO₂ circulation for different circulation rates, while the reduction in temperature of the produced fluid over time for the same CO₂ circulation rates is shown in Figure 10b. Together these figures illustrate that higher CO₂ circulation rates primarily increase initial geothermal energy production at the expense of more rapid reservoir heat energy (or temperature) depletion rates.

Conclusions

Simulations are conducted to study the performance of a CO₂-limited, axi-symmetric CO₂-Plume Geothermal (CPG) system with a vertical injection and a horizontal, circular production well as a function of reservoir depth, permeability, geothermal gradient, well spacing and CO₂ circulation rate. The initial amount of CO₂ required and the percentage of the heat depletion rate over time for various scenarios are tabulated.

- The finite amount of initially injected CO₂ required to operate a CPG system increases with increasing well spacing between injection and production wells, permeability of the reservoir, and reservoir depth, and decreases for locations with higher geothermal gradients.
- Reservoir heat depletion rates decrease when the spacing between injection and production wells is increased.

- Heat extraction rates of the investigated system and a geothermal gradient of 34 °C/km are approximately 8 MW, 15 MW, and 25 MW for 1.5 km, 2.5 km, and 3.5 km deep reservoirs, respectively, before reservoir heat depletion begins.
- Heat extraction rates for a reservoir at a depth of 2.5 km and a geothermal gradient of 20 °C/km, 34 °C/km, and 50 °C/km are 5 MW, 15 MW and 30 MW, respectively.
- The time it takes since the onset of CO₂ production and circulation for reservoir temperatures to start depleting is less for higher geothermal gradients and for both particularly shallow (1.5 km) and deep (3.5 km) reservoirs.
- Heat extraction rates for a reservoir at a depth 2.5 km, with a geothermal gradient of 34 °C/km, and with circulation rates of 4 Mtonnes/yr, 5Mtonnes/yr, and 6 Mtonnes/yr are 15 MW, 18 MW, and 22 MW, respectively. However, the reservoir starts to deplete earlier for higher fluid circulation rates.
- The CO₂ production rate has to be set based on the desired reservoir longevity and (initial versus long-term) energy production rate objectives.

Acknowledgments

This work was supported in part by a Sustainable Energy Pathways (SEP) grant from the U.S. National Science Foundation (NSF) under Grant Number SEP-1230691, by the U.S. Department of Energy (DOE) under Grant Number DE-EE0002764, and by a grant from the Initiative for Renewable Energy and the Environment (IREE), a signature program of the Institute on the Environment (IonE) at the University of Minnesota (UMN), U.S.A.. Martin Saar additionally thanks the Werner Siemens Foundation for their endowment of the Geothermal Energy and Geofluids Chair at ETH Zurich (ETHZ) and the Gibson endowment for their support of the Hydrogeology and Geofluids Research group at UMN. Any opinions, findings, conclusions,

and/or recommendations expressed in this material are those of the authors and do not necessarily reflect the views of the NSF, DOE, IREE, IonE, UMN, ETHZ, the Werner Siemens Foundation, or the Gibson Foundation. Finally, we thank the two anonymous reviewers and the Associate Editor, Dr. J. N. Moore, for their helpful comments that greatly improved this paper.

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.

References

- Adams, B. M., Kuehn, T. H., Bielicki, J. M., Randolph, J. B., & Saar, M. O. (2014). "On the importance of the thermosiphon effect in CPG (CO₂ plume geothermal) power systems." *Energy* 69:409-418.
- Adams, B. M., Kuehn, T. H., Bielicki, J. M., Randolph, J. B., & Saar, M. O. (2015). "A comparison of electric power output of CO₂ plume geothermal (CPG) and brine geothermal systems for varying reservoir conditions." *Applied Energy* 140:365-377.
- Alcott, A., Swenson, D., & Haredman, B. (2006). "Using petrasim to create, execute, and post-process TOUGH2 models." *Proceedings of TOUGH Symposium, Lawrence Berkeley National Laboratory, Berkeley, CA.*
- Atrens, A. D., Gurgenci, H. & Rudolph, V. (2009). "CO₂ Thermosiphon for competitive geothermal power generation." *Energy & Fuels* 23 (1):553-557.

- Atrens, A. D., Gurgenci, H. & Rudolph, V. (2010). "Electricity generation using a carbon-dioxide thermosiphon." *Geothermics* 39 (2):161-169.
- Brown, D. W. (2000). "A hot dry rock geothermal energy concept utilizing supercritical CO₂ instead of water." *Proceedings of the Twenty-Fifth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA.*
- Brown, D. W. (2003). Geothermal energy production with supercritical fluids. U.S. Patent No. 6,668,554.
- Buscheck, T. A., Elliot, T. R., Celia, M. A., Chen, M., Sun, Y., Hao, Y., Lu, C., Wolery, T. J., & Aines, R. D. (2013). "Integrated geothermal-CO₂ reservoir systems: Reducing carbon intensity through sustainable energy production and secure CO₂ storage." *Energy Procedia* 37:6587-6594.
- Buscheck, T. A., Bielicki, J. M., Randolph, J. B., Chen, M., Hao, Y., Edmunds, T. A., Adams, B. M., & Sun, Y. (2014). "Multi-fluid geothermal energy systems in stratigraphic reservoirs: Using brine, N₂, and CO₂ for dispatchable renewable power generation and bulk energy storage." No. LLNL-CONF-650283, *Proceedings of the Thirty-Ninth Workshop on Geothermal Reservoir Engineering, Stanford University, Stanford, CA.*
- Dezayes, C., Genter, A., Hooijkaas, G. R. (2005). "Deep-seated geology and fracture system of the EGS Soultz reservoir (France) based on recent 5km depth boreholes." *Proceedings of World Geothermal Congress, Antalya, Turkey.*
- Evans, K., Moriya, H., Niitsuma, H., Jones, R., Phillips, W., Genter, A., Sausse, J., Jung, R., Baria, R. (2005). "Microseismicity and permeability enhancement of hydrogeologic structures during massive fluid injections into granite at 3 km depth at the Soultz HDR site." *Geophysical Journal International* 160 (1):388-412.

469 Fouillac, C., Sanjuan, B., Gentier, S., Czernichowski-Lauriol, I. (2004). "Could sequestration of
 470 CO₂ be combined with the development of enhanced geothermal systems." *Third Annual*
 471 *Conference on Carbon Capture and Sequestration*, Alexandria, VA.

472 Garapati, N., Randolph, J. B., & Saar, M. O. (2014). "Total Heat Energy Output From, Thermal
 473 Energy Contributions To, and Reservoir Development of CO₂ Plume Geothermal (CPG)
 474 Systems." *Proceedings of the Thirty-Ninth Workshop on Geothermal Reservoir*
 475 *Engineering, Stanford University*, Stanford, CA.

476 Gardes, R. A. (1995). Method of drilling multiple radial wells using multiple string downhole
 477 orientation. U.S. Patent No. 5,394,950.

478 Gardes, R. A. (1998). Method and system for drilling underbalanced radial wells utilizing a dual
 479 string technique in a live well. U.S. Patent No. 5,720,356.

480 Giardini, D. (2009). "Geothermal quake risks must be faced." *Nature* 462 (7275):848-849.

481 IPCC. (2007). *Climate change 2007: Impacts, adaptation and vulnerability*. Cambridge
 482 University Press Cambridge.

483 IPCC. (2014). *Climate change 2014: Mitigation of climate change*. Cambridge University Press
 484 Cambridge.

485 Kong, X. -Z., Tutolo, B. M., & Saar, M. O. (2013). "DBCreate: A SUPCRT92-based program
 486 for producing EQ3/6, TOUGHREACT, and GWB thermodynamic databases at user-
 487 defined *T* and *P*." *Computers & Geosciences* 51:415-417,
 488 doi:10.1016/j.cageo.2012.08.004, 2013.

489 Luhmann, A. J., Kong, X. -Z., Tutolo, B. M., Ding, K., Saar, M. O., & Seyfried Jr, W. E. (2013).
 490 "Permeability reduction produced by grain reorganization and accumulation of exsolved
 491 CO₂ during geologic carbon sequestration: A new CO₂ trapping mechanism."

492 *Environmental Science and Technology*, *Special Issue: Carbon Sequestration* 47:
 493 242–251, dx.doi.org/10.1021/es3031209.

494 Luhmann, A. J., Kong, X. -Z., Tutolo, B. M., Garapati, N., Bagley, B. C., Saar, M. O., &
 495 Seyfried Jr, W. E. (2014). "Experimental dissolution of dolomite by CO₂-charged brine at
 496 100°C and 150 bar: Evolution of porosity, permeability, and reactive surface area."
 497 *Chemical Geology* 380:145-160.

498 Majer, E. L., Baria, R., Stark, M., Oates, S., Bommer, J., Smith, B., Asanuma, H. (2007).
 499 "Induced seismicity associated with enhanced geothermal systems." *Geothermics* 36
 500 (3):185-222.

501 Metz, B., Davidson, O., De Coninck, H. C., Loos, M., & Meyer, L. A. (2005). "IPCC, 2005:
 502 IPCC special report on carbon dioxide capture and storage. Prepared by Working Group
 503 III of the Intergovernmental panel on Climate Change." Cambridge University Press
 504 Cambridge.

505 National Institute of Standards and Technology. NIST Reference Fluid Thermo-dynamic and
 506 Transport Properties Database (REFPROP): Version 9.0, 2011.

507 Noble, J. B. (1992). Directional drilling apparatus and method. U.S. Patent No. 5,113,953.

508 Pollack, H. N., Hurter, S. J., Johnson, J. R. (1993). "Heat flow from the Earth's interior: Analysis
 509 of the global data set." *Reviews of Geophysics* 31 (3):267-280.

510 Pruess, K. (2004). "The TOUGH codes—A family of simulation tools for multiphase flow and
 511 transport processes in permeable media." *Vadose Zone Journal* 3 (3):738-746.

512 Pruess, K. (2005). ECO2N: A TOUGH2 fluid property module for mixtures of water, NaCl, and
 513 CO₂: Lawrence Berkeley National Laboratory Berkeley.

514 Pruess, K. (2006). "Enhanced geothermal systems (EGS) using CO₂ as working fluid—a novel
515 approach for generating renewable energy with simultaneous sequestration of carbon."
516 *Geothermics* 35 (4):351-367.

517 Pruess, K. (2007). "Role of fluid pressure in the production behavior of enhanced geothermal
518 systems with CO₂ as working fluid." *GRC Trans* 31:307-311.

519 Pruess, K. (2008). "On production behavior of enhanced geothermal systems with CO₂ as
520 working fluid." *Energy Conversion and Management* 49 (6):1446-1454.

521 Pruess, K., Moridis, G., Oldenburg, C. (1999). TOUGH2 user's guide, version 2.0: Lawrence
522 Berkeley National Laboratory Berkeley.

523 Randolph, J.B., & Saar, M. O. (2010). "Coupling geothermal energy capture with carbon dioxide
524 sequestration in naturally permeable, porous geologic formations: A comparison with
525 enhanced geothermal systems." *GRC Trans* 34:433-438.

526 Randolph, J.B., & Saar, M. O. (2011a). "Coupling carbon dioxide sequestration with geothermal
527 energy capture in naturally permeable, porous geologic formations: Implications for CO₂
528 sequestration." *Energy Procedia* 4:2206-2213.

529 Randolph, J.B., & Saar, M. O. (2011b). "Combining geothermal energy capture with geologic
530 carbon dioxide sequestration." *Geophysical Research Letters* 38 (10), L10401,
531 doi:10.1029/2011GL047265.

532 Randolph, J.B., Adams, B. M., Kuehn, T. H., & Saar, M. O. (2012). "Wellbore heat transfer in
533 CO₂-based geothermal systems." *GRC Trans* 36:549-554.

534 Randolph, J.B., Saar, M. O., & Bielicki, J. M., 2013. "Geothermal energy production at geologic
535 CO₂ sequestration sites: Impact of thermal drawdown on reservoir pressure." *Energy*
536 *Procedia* 37:6625-6635.

537 Saar, M. O. (2011). "Review: Geothermal heat as a tracer of large-scale groundwater flow and as
538 a means to determine permeability fields." *Hydrogeology Journal* 19 (1):31-52.

539 Saar, M. O., Randolph, J. B., Kuehn, T. H., & the Regents of the University of Minnesota (2012-
540 2015). "Carbon dioxide-based geothermal energy generation systems and methods related
541 thereto." U.S. Patent No. 8,316,955 (issued 2012); Canada Patent No. 2.753.393 (issued
542 2013); Europe Patent No. 2406562 (issued 2014); Australia Patent No. 2010223059
543 (issued 2015).

544 Spycher, N., Pruess, K. (2011). "A model for thermophysical properties of CO₂-brine mixtures at
545 elevated temperatures and pressures." *Proceedings Thirty-Sixth Workshop on Geothermal
546 Reservoir Engineering, Stanford University, Stanford, CA.*

547 Steadman, E. N., Daly, D. J., de Silva, L. L., Harju, J. A., Jensen, M. D., O'Leary, E. M., Peck,
548 W. D., Smith, S. A., & Sorensen, J. A. (2006). "Plains CO₂ reduction (PCOR) partnership
549 (phase 1) final report/July-September 2005 quarterly report." *Energy and Environ. Res.
550 Cent., University of North Dakota, Grand Forks.*

551 Tutolo, B. M., Luhmann, A. J., Kong, X. -Z., Saar, M. O., & Seyfried Jr, W. E. (2014a).
552 "Experimental observation of permeability changes in dolomite at CO₂ sequestration
553 conditions." *Environmental Science and Technology*, DOI: 10.1021/es4036946.

554 Tutolo, B. M., Schaen, A. T., Saar, M. O., & Seyfried Jr, W. E. (2014b). "Implications of the
555 redissociation phenomenon for mineral-buffered fluids and aqueous species transport at
556 elevated temperatures and pressures." *Applied Geochemistry* in press.

557 Tutolo, B. M., Kong, X. -Z., Seyfried Jr, W. E., & Saar, M. O. (2014c). "Internal consistency in
558 aqueous geochemical data revisited: Applications to the aluminum system." *Geochimica
559 et Cosmochimica Acta* 133: 216–234.

560 Tutolo, B. M., Luhmann, A. J., Kong, X. -Z., Saar, M. O., & Seyfried Jr, W. E. (2015a). "CO₂
561 sequestration in feldspar-rich sandstone: the importance of saturation state and fluid
562 composition." *Geochimica et Cosmochimica Acta*; tentatively accepted on Dec. 11, 2014.

563 Tutolo, B. M., Kong, X. -Z., Luhmann, A. J., Seyfried Jr, W. E., & Saar, M. O. (2015b). "High-
564 performance computing examining the effects of thermal gradients on CCUS carbonate
565 reservoir permeabilities." To be submitted to *International Journal of Greenhouse Gas*
566 *Control in February*.

567 Welch, P., Boyle, P. (2009). "New turbines to enable efficient geothermal power plants." *GRC*
568 *Trans* 33:765-772.

Appendix A

In order to study the effect of reservoir-caprock interface dip, and associated skewing of the CO₂-plume on the heat extraction characteristics of a CO₂-Plume Geothermal (CPG) system, we consider a 3D cartesian model to represent a reservoir with a thickness of 50 m with the injection well at the center fully penetrating through the reservoir and, horizontal production well at the top of the reservoir immediately underneath the caprock. The simulations are performed with the Petrasim 5 (Alcott *et al.*, 2006) user interface running the TOUGH2-ECO2N (Pruess 2005) simulator. We consider three reservoir-caprock interface dip angles: i) no dip, ii) dip = 5°, and iii) dip = 15°. The reservoir and fluid parameters are the same as given in Tables 2 and 3. The CO₂ plume is built by initial injection of 2 Mtonnes of CO₂ over 2 years from the central injection well.

Figure A1 shows the CO₂ plume formation as CO₂ mass fraction along the reservoir thickness at the end of injection. As expected, the CO₂ plume moves up-dip toward shallower depths. The horizontal, production well at the top of the reservoir, immediately below the caprock, is placed in accordance to the CO₂ plume migration (i.e., potentially off-centered) as shown in Figure A2 so that the CO₂ mass fraction in the *produced* fluid is approximately 94% (the suggested minimum required produced CO₂ mass fraction as described in the main text). CO₂ is produced and circulated at a rate of 1 Mtonne/Year for 25 years. Figure A3 shows that the heat extraction rate over the years is virtually the same for symmetric and skewed CO₂ plume systems. Therefore, suggesting that simplified axisymmetric simulations, as done in the simulations for the main text, are likely justified to conduct various simulations over a parametric space to gain first-order insights with decreased computational effort.

Appendix B

In contrast to the main section of this paper, we investigate here briefly the effects of reinjecting into the reservoir small amounts of brine that are co-produced with the CO₂ as indicated by CO₂ saturation fractions <1 in Figures 6-9. Thus, rather than assuming separation of brine from the produced CO₂, the following simulations assume that all of the produced CO₂ and brine is cooled at the surface during the expansion and power production process (not explicitly simulated here) and then reinjected into the geothermal reservoir. Brine has a lower mobility (i.e., a larger kinematic viscosity) than supercritical CO₂ at a given temperature and thus accumulates near the injection well as shown in Figure B1. Such brine accumulation reduces the relative permeability for the CO₂ phase which in turn increases the pore-fluid pressure in the reservoir around the injection well (Figure B2).

For this reason, we recommend removal of any produced brine from the produced CO₂ before the cooled CO₂ is reinjected into the reservoir. Separated brine may be re-injected into the formation away from the CO₂ plume, providing an additional means of controlling and directing the CO₂ plume pressure field and fluid flow direction and avoiding the need to treat and dispose of the CO₂ near the land surface (Buscheck et al., 2014).

TABLES

Table 1 Numerical model parameters for the base case.

Model Parameter/Condition	
Number of grid cells, vertical	20 equidistant layers
Number of grid cells, horizontal	50 logarithmically spaced with fine grid around injection and production wells.
Numerical grid configuration	Radially symmetric about the injection well
Well spacing [m]	707
Well orientation	Vertical (injection), horizontal circular (production)
Boundary conditions (top/bottom)	No fluid flow, semi-analytic heat exchange
Boundary conditions (lateral)	No fluid or heat flow
Initial conditions	Hydrostatic equilibrium, no heat flow, all pore space occupied by brine

Table 2 Reservoir physical parameters for the base case.

Reservoir Parameter/Condition	
Average depth, D [m]	2500
Horizontal permeability, k_x [m ²]	5×10^{-14}
Vertical permeability, k_z [m ²]	2.5×10^{-14}
	2.10
Thermal conductivity [W/m/ °C]	
Thickness [m]	50
	100
Initial temperature, T [°C]	
Porosity	0.10

	1000
Rock specific heat [J/kg/°C]	
Rock grain density [kg/m ³]	2650
Radius [m]	100,000
	34
Geothermal gradient [°C/km]	

613

614 **Table 3 Reservoir fluid parameters.**

Fluid Property	
Residual brine saturation fraction	0.30
van Genuchten, m	0.457
Native brine NaCl saturation [ppm]	200,000
Residual CO ₂ saturation	0.05
van Genuchten a [1/Pa]	5.1×10^{-5}

615

616 **Table 4 Pressure and temperature conditions at different depths.**

Reservoir Parameter/Condition			
Average depth, D [km]	1.5	2.5	3.5
	66	100	134
Initial temperature, T [°C]			
Pressure [bar]	150	250	350

35 46 58

CO₂ injection temperature, T_{inj} [°C]

617

618 **Table 5 Initial injected CO₂ mass and the percentage decrease in the heat extraction rate**
 619 **(HER) over 20 years from a reservoir with a horizontal permeability ($k_x = 5 \times 10^{-14} \text{ m}^2$) and a**
 620 **CO₂ circulation rate of 4 Mtonnes/Year for various scenarios.**

Gradient (°C/km)	Depth (km)	Well Spacing (m)	Injected CO ₂ (Mtonnes)	CO ₂ mass fraction	Max HER (MW)	HER at Year 20 (MW)	Decrease of HER over 20 years (%)
50	1.5	500	2	0.993	20	6	70
		707	2	0.975	20	13	35
		1000	2	0.72	20	18	10
			4	0.976	20	18	10
	2.5	500	2	0.981	30	12	60
		707	2	0.95	30	23.5	21.7
		1000	4	0.95	30	30	0
	3.5	500	2	0.952	42	16	61.9
		707	2	0.92	42	30	28.6
			3	0.952	42	30	28.6
		1000	4	0.912	42	38.5	8.3
			5	0.95	42	38.5	8.3
34	1.5	500	2	>0.99	8.25	2	75.8
		707	2	0.952	8.25	6	27.2
		1000	3	0.8	8.25	7.75	6.1
			4	0.957	8.25	7.75	6.1
	2.5	500	2	0.987	15	7	53.3

20	3.5	707	2	0.932	15	13.25	11.7
		1000	4	0.94	15	15	0
		500	2	0.978	25	12.5	50
		707	2	0.91	25	20.25	19
			3	0.975	25	21	16
		1000	4	0.905	25	24	4
	2.5		5	0.954	25	24	4
		500	2	0.979	5	2.5	50
		707	2	0.92	5	4.75	5
			3	0.967	5	4.75	5
		1000	4	0.91	5	5	0
			5	0.95	5	5	0
	3.5	500	2	0.978	6	3.5	41.7
		707	2	0.9	6	5.75	4.2
			3	0.962	6	5.75	4.2
		1000	4	0.895	6	6	0
			5	0.94	6	6	0
		500	2	0.972	12	6	50
	5	707	2	0.855	12	11	8.4
			3	0.954	12	11	8.4
		1000	4	0.865	12	12	0
			5	0.92	12	12	0
			6	0.946	12	12	0

621

622 **Table 6 Optimum circulation rates for different well spacings to maintain minimum up-**
623 **coning of the CO₂-brine interface into the production well.**

Well Spacing (m)	Circulation Rate (Mtonne/Yr)
500	2

707	4
1000	8

624

625

Figure Captions

Figure 1. a) Illustration showing a vertical cross section through one possible implementation of a simplified radial-reservoir CO₂-Plume Geothermal (CPG) system (modified from Randolph and Saar, 2011b; Saar et al., 2012-2015), implemented in a deep saline aquifer. Shown are both a direct (left side) and an indirect, i.e., binary Organic Rankine Cycle (ORC) implementation (right side). Numbers are CO₂ state points corresponding to the diagram below. b) Enthalpy versus pressure diagram (with green, blue, and gray lines indicating enthalpy, density, and temperature, respectively), showing state points of the CO₂ working fluid as it moves through an idealized, direct Carnot Power Cycle (data for figure generation is from the National Institute of Standards and Technology). Sub-cooled liquid CO₂ is injected at the surface at State 1, where it moves adiabatically and nearly isentropically within the injection well to State 2, transitioning to a supercritical fluid, as pressure and temperature increase above the critical point ($T_c=304$ K, $P_c=7.4$ MPa). The CO₂ then moves through the reservoir, heating to the reservoir temperature, reducing in pressure until it reaches the production well at State 3, where it is at the reservoir hydrostatic pressure. The CO₂ then rises adiabatically (Randolph et al., 2012) through the production well to State 4. At the surface, the CO₂ expands and cools through a two-phase turbine, reaching State 5. The CO₂ then further cools and condenses isobarically through the cooling or condensing tower back to State 1, concluding the power cycle. Note that CO₂ (as opposed to water) can be cooled to $T<0^{\circ}\text{C}$ in a dry-bulb cooling tower (from State 5 to State 1) in cold climates, further increasing power cycle efficiency.

Figure 2. Simplified pressure profiles along the injection and production wells for a reservoir at a depth of 2.5 km and temperatures of 100°C and 150°C. A pressure difference of 72 bar and 110 bar, respectively, is available at the surface plant for power generation. ΔP is the pressure difference from the injection to the production well. Modified from Randolph et al. (2013) and from Adams et al. (2014).

Figure 3. Three-dimensional (3D), axisymmetric model with a cross section of the CO₂-Plume Geothermal (CPG) reservoir showing grid discretization and placement of wells. The caprock bottom is located at a depth of 2475 m. The injection well is vertical and fully penetrating within the reservoir and constitutes the axis of symmetry. The production well is horizontal, circular and located just below the caprock at various distances from the injection well (here shown is 707 m). The model extends horizontally to 100 km (not shown) to minimize numerical boundary effects, with logarithmically increasing horizontal grid spacing away from the injection well but horizontal refinement of grid spacing near the production well. The block diagrams to the right show symmetric (top) and asymmetric or skewed (bottom) CO₂ plume formation as described in the main text and Appendix A.

Figure 4. CO₂ mass flow rate during the initial CO₂ plume formation period (dashed line) and during CO₂ production and circulation (solid line) for the base case. CO₂ plume formation occurs during times before 0 years. CO₂ production and circulation starts at time $t=0$ years. Simulations are performed for 100 years.

Figure 5. Radial cross section (as shown in Figure 3) contour plots of the CO₂ saturation fraction in the geothermal reservoir pore fluid after initial CO₂ plume formation by injecting (a) 2 Mtonnes and (b) 4 Mtonnes of CO₂ over 2.5 years. The green, vertical line to the left marks the location of the vertical injection well, fully penetrating within the reservoir. The red squares at the top of the reservoir (directly below the caprock) indicate considered locations for the horizontal, circular production wells (at radial distances from the injection well of 500 m, 707 m, and 1000 m) as discussed in the main text. The numerical models extend horizontally to 100 km (not shown) to minimize boundary effects. This figure represents CO₂ saturation before any fluid production commences. Note that CO₂ saturation contours reflect conditions in the reservoir and not in the produced fluid, which are significantly higher (see

subsequent figures) due to the high mobility of CO₂ compared to brine, preferentially drawing CO₂ into the production well, as explained in the main text.

Figure 6. Produced CO₂ mass fraction (a) and reservoir heat energy extraction [MW] (b) over time for horizontal distances between the vertical injection well and the horizontal, circular production well of 500 m (solid line), 707 m (dashed line), and 1000 m (dotted line). The CO₂ circulation rate through the system is shown by the dash-dotted line that corresponds to the secondary axis. The minimum acceptable CO₂ mass fraction is approximately 0.94, although values as low as 0.93 are still considered acceptable as discussed in the main text.

Figure 7. Produced CO₂ mass fraction (a) and reservoir thermal heat energy extraction [MW] (b) over time for reservoir depths of 1.5 km (solid line), 2.5 km (dashed line), and 3.5 km (dotted line). The CO₂ circulation rate through the system is shown by the dash-dotted line corresponding to the secondary axis. Given the approximate nature of the 0.94 CO₂ mass fraction limit (see text), a CO₂ mass fraction of 0.93 (gray area), for the 2.5 km reservoir depth base case, is still considered acceptable.

Figure 8. Produced CO₂ mass fraction (a) and CPG heat energy extraction rate [MW] (b) from the reservoir over time for geothermal gradients of 50 °C/km (solid line), 34 °C/km (dashed line), and 20 °C/km (dotted line). The minimum acceptable CO₂ mass fraction is approximately 0.94, although values as low as 0.93 are still considered acceptable as discussed in the main text. The CO₂ circulation rate through the system is shown by the dash-dotted, line with values indicated by the secondary axis. The inset figure in (b) is a close-up of the first 20 years. Just before 2 years, there is a dip in the heat extraction rate for the 20 °C/km geothermal gradient case, which is explained in the main text.

Figure 9. Produced CO₂ mass fraction (a) and temperature of the reservoir fluid (mostly CO₂) near the production well (b) over time for various horizontal permeabilities, k_x . The CO₂ circulation rate through the system is shown by the dash-dotted line on the secondary axis. The black horizontal line at 0.94 is the approximate minimum limit for the CO₂ mass fraction allowed in the turbine as explained in the main text. The vertical permeability, k_z , is adjusted to maintain a permeability anisotropy ratio of $k_x/k_z=2$ in all cases.

Figure 10. Heat energy extraction rate [MW] from the reservoir (a), and temperature of the produced fluid (b) for various fluid production and circulation rates over time. The CO₂ circulation rates through the system are indicated by the secondary axis.

Figure A1. Cross section showing CO₂ plume formation (as CO₂ saturation) along the thickness of the reservoir after injection of 2 Mtonnes of CO₂ over 2 years from the central injection well for reservoirs with 0° dip (a), 5° dip (b), and 15° dip (c). The skew direction of the CO₂ plume, caused by the reservoir-caprock interface dip, is indicated by the arrow in (b) and (c).

Figure A2. Map-view plot showing the CO₂ Plume formation (as CO₂ saturation) around the vertical injection well and the approximately circular, horizontal production well (yellow octagon with thin black line) at the top of the reservoir. The CO₂ plume is symmetric around the injection well for a reservoir-caprock interface dip of 0° (a). The CO₂ plume is skewed farther to the left (up-dip) for increasing interface dips of 5° (b) and 15° (c). The skew direction of the CO₂ plume, caused by the reservoir-caprock interface dip, is indicated by the arrow in (b) and (c).

Figure A3. Heat energy extraction rate with time from reservoirs with reservoir-caprock interface dips of 0° (solid line), 5° dip (dashed line), and 15° dip (dotted line) and respective CO₂ plume distributions as shown in Figures A1 and A2.

Figure B1. Radial cross section (Figure 3) through the reservoir with the reservoir center located at a depth of 2.5 km. The figure shows contour plots of the aqueous-phase and the CO₂-phase saturation fractions in the geothermal reservoir pore fluid near the injection well (left boundary) after (a) 0.25 year, (b) 1 year, (c) 2 years, and (d) 5 years. Over time, the aqueous phase saturation increases near the bottom of the injection well because, in contrast to all other simulations, these simulations assume that water that is (minimally) produced along with the CO₂, is reinjected into the reservoir.

Figure B2. Reservoir pore-fluid pressure near the vertical injection well (dashed line) and near the horizontal, circular production well at the top of the reservoir at a distance of 707 m (base case) from the injection well (solid line) over time. The pressure near the injection well varies in accordance with the brine mass fraction in the produced fluid (Figure 6a – base case). The pressure around the injection well increases due to the brine accumulation near the injection well (Figure B1), which reduces the relative permeability for the CO₂ phase. For comparison, no such pore-fluid pressure increase over time is observed near the production well.

Figure 1. a) Illustration showing a vertical cross section through one possible implementation of a simplified radial-reservoir CO₂-Plume Geothermal (CPG) system (modified from Randolph and Saar, 2011b; Saar *et al.*, 2012-2015), implemented in a deep saline aquifer. Shown are both a direct (left side) and an indirect, i.e., binary Organic Rankine Cycle (ORC) implementation (right side). Numbers are CO₂ state points corresponding to the diagram below. b) Enthalpy versus pressure diagram (with green, blue, and gray lines indicating enthalpy, density, and temperature, respectively), showing state points of the CO₂ working fluid as it moves through an idealized, direct Carnot Power Cycle (data for figure generation is from the National Institute of Standards and Technology). Sub-cooled liquid CO₂ is injected at the surface at State 1, where it moves adiabatically and nearly isentropically within the injection well to State 2, transitioning to a supercritical fluid, as pressure and temperature increase above the critical point ($T_c=304$ K, $P_c=7.4$ MPa). The CO₂ then moves through the reservoir, heating to the reservoir temperature, reducing in pressure until it reaches the production well at State 3, where it is at the reservoir hydrostatic pressure. The CO₂ then rises adiabatically (Randolph *et al.*, 2012) through the production well to State 4. At the surface, the CO₂ expands and cools through a two-phase turbine, reaching State 5. The CO₂ then further cools and condenses isobarically through the cooling or condensing tower back to State 1, concluding the power cycle. Note that CO₂ (as opposed to water) can be cooled to $T<0^{\circ}\text{C}$ in a dry-bulb cooling tower (from State 5 to State 1) in cold climates, further increasing power cycle efficiency.

Figure 2. Simplified pressure profiles along the injection and production wells for a reservoir at a depth of 2.5 km and temperatures of 100°C and 150°C. A pressure difference of 72 bar and 110 bar, respectively, is available at the surface plant for power generation. ΔP is the pressure difference from the injection to the production well. Modified from Randolph *et al.* (2013) and from Adams *et al.* (2014).

Figure 3. Three-dimensional (3D), axisymmetric model with a cross section of the CO₂-Plume Geothermal (CPG) reservoir showing grid discretization and placement of wells. The caprock bottom is located at a depth of 2475 m. The injection well is vertical and fully penetrating within the reservoir and constitutes the axis of symmetry. The production well is horizontal, circular and located just below the caprock at various distances from the injection well (here shown is 707 m). The model extends horizontally to 100 km (not shown) to minimize numerical boundary effects, with logarithmically increasing horizontal grid spacing away from the injection well but horizontal refinement of grid spacing near the production well. The block diagrams to the right show symmetric (top) and asymmetric or skewed (bottom) CO₂ plume formation as described in the main text and Appendix A.

Figure 4. CO₂ mass flow rate during the initial CO₂ plume formation period (dashed line) and during CO₂ production and circulation (solid line) for the base case. CO₂ plume formation occurs during times before 0 years. CO₂ production and circulation starts at time t =0 years. Simulations are performed for 100 years.

Figure 5. Radial cross section (as shown in Figure 3) contour plots of the CO₂ saturation fraction in the geothermal reservoir pore fluid after initial CO₂ plume formation by injecting (a) 2 Mtonnes and (b) 4 Mtonnes of CO₂ over 2.5 years. The green, vertical line to the left marks the location of the vertical injection well, fully penetrating within the reservoir. The red squares at the top of the reservoir (directly below the caprock) indicate considered locations for the horizontal, circular production wells (at radial distances from the injection well of 500 m, 707 m, and 1000 m) as discussed in the main text. The numerical models extend horizontally to 100 km (not shown) to

minimize boundary effects. This figure represents CO₂ saturation before any fluid production commences. Note that CO₂ saturation contours reflect conditions in the reservoir and not in the produced fluid, which are significantly higher (see subsequent figures) due to the high mobility of CO₂ compared to brine, preferentially drawing CO₂ into the production well, as explained in the main text.

Figure 6. Produced CO₂ mass fraction (a) and reservoir heat energy extraction [MW] (b) over time for horizontal distances between the vertical injection well and the horizontal, circular production well of 500 m (solid line), 707 m (dashed line), and 1000 m (dotted line). The CO₂ circulation rate through the system is shown by the dash-dotted line that corresponds to the secondary axis. The minimum acceptable CO₂ mass fraction is approximately 0.94, although values as low as 0.93 are still considered acceptable as discussed in the main text.

Figure 7. Produced CO₂ mass fraction (a) and reservoir thermal heat energy extraction [MW] (b) over time for reservoir depths of 1.5 km (solid line), 2.5 km (dashed line), and 3.5 km (dotted line). The CO₂ circulation rate through the system is shown by the dash-dotted line corresponding to the secondary axis. Given the approximate nature of the 0.94 CO₂ mass fraction limit (see text), a CO₂ mass fraction of 0.93 (gray area), for the 2.5 km reservoir depth base case, is still considered acceptable.

Figure 8. Produced CO₂ mass fraction (a) and CPG heat energy extraction rate [MW] (b) from the reservoir over time for geothermal gradients of 50 °C/km (solid line), 34 °C/km (dashed line), and 20 °C/km (dotted line). The minimum acceptable CO₂ mass fraction is approximately 0.94, although values as low as 0.93 are still considered acceptable as discussed in the main text. The CO₂ circulation rate through the system is shown by the dash-dotted, line with values indicated by the secondary axis. The inset figure in (b) is a close-up of the first 20 years. Just before 2 years, there is a dip in the heat extraction rate for the 20 °C/km geothermal gradient case, which is explained in the main text.

Figure

Figure 9. Produced CO₂ mass fraction (a) and temperature of the reservoir fluid (mostly CO₂) near the production well (b) over time for various horizontal permeabilities, k_x . The CO₂ circulation rate through the system is shown by the dash-dotted line on the secondary axis. The black horizontal line at 0.94 is the approximate minimum limit for the CO₂ mass fraction allowed in the turbine as explained in the main text. The vertical permeability, k_z , is adjusted to maintain a permeability anisotropy ratio of $k_x/k_z=2$ in all cases.

Figure 10. Heat energy extraction rate [MW] from the reservoir (a), and temperature of the produced fluid (b) for various fluid production and circulation rates over time. The CO₂ circulation rates through the system are indicated by the secondary axis.

Figure A1. Cross section showing CO₂ plume formation (as CO₂ saturation) along the thickness of the reservoir after injection of 2 Mtonnes of CO₂ over 2 years from the central injection well for reservoirs with 0° dip (a), 5° dip (b), and 15° dip (c). The skew direction of the CO₂ plume, caused by the reservoir-caprock interface dip, is indicated by the arrow in (b) and (c).

Figure A2. Map-view plot showing the CO₂ Plume formation (as CO₂ saturation) around the vertical injection well and the approximately circular, horizontal production well (yellow octagon with thin black line) at the top of the reservoir. The CO₂ plume is symmetric around the injection well for a reservoir-caprock interface dip of 0° (a). The CO₂ plume is skewed farther to the left (up-dip) for increasing interface dips of 5° (b) and 15° (c). The skew direction of the CO₂ plume, caused by the reservoir-caprock interface dip, is indicated by the arrow in (b) and (c).

Figure A3. Heat energy extraction rate with time from reservoirs with reservoir-caprock interface dips of 0° (solid line), 5° dip (dashed line), and 15° dip (dotted line) and respective CO₂ plume distributions as shown in Figures A1 and A2.

Figure B1. Radial cross section (Figure 3) through the reservoir with the reservoir center located at a depth of 2.5 km. The figure shows contour plots of the aqueous-phase and the CO₂-phase saturation fractions in the geothermal reservoir pore fluid near the injection well (left boundary) after (a) 0.25 year, (b) 1 year, (c) 2 years, and (d) 5 years. Over time, the aqueous phase saturation increases near the bottom of the injection well because, in contrast to all other simulations, these simulations assume that water that is (minimally) produced along with the CO₂, is reinjected into the reservoir.

Figure B2. Reservoir pore-fluid pressure near the vertical injection well (dashed line) and near the horizontal, circular production well at the top of the reservoir at a distance of 707 m (base case) from the injection well (solid line) over time. The pressure near the injection well varies in accordance with the brine mass fraction in the produced fluid (Figure 6a – base case). The pressure around the injection well increases due to the brine accumulation near the injection well (Figure B1), which reduces the relative permeability for the CO₂ phase. For comparison, no such pore-fluid pressure increase over time is observed near the production well.