Impact of reservoir permeability on the choice of subsurface geothermal heat exchange fluid: CO$_2$ versus water and native brine.

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Abstract
Geothermal systems utilizing carbon dioxide (CO$_2$) as the subsurface heat exchange fluid in naturally porous, permeable geologic formations have been shown to provide improved geothermal heat energy extraction, even at low resource temperatures. Such systems, termed CO$_2$ Plume Geothermal (CPG) systems, have the potential to permit expansion of geothermal energy utilization while supporting rapid implementation through the use of existing technologies. Here, we explore CPG heat extraction as a function of reservoir permeability and in comparison to water and brine geothermal heat extraction. We show that for reservoir permeabilities below 2 x 10$^{-14}$ m$^2$, CO$_2$-based geothermal provides better electric power production efficiency than both water- and brine-based systems.

Introduction
Geothermal energy offers clean, reliable electric power with no need for grid-scale energy storage. To support future investment in, and growth of, the industry, and to ensure geothermal plays a large role in the future energy landscape, new technology will be critical. Here, we discuss a new method with the potential to permit widespread expansion of geothermal energy utilization: CO$_2$ Plume Geothermal (CPG) systems.

Carbon dioxide sequestration in deep saline aquifers and as a component of enhanced oil and hydrocarbon recovery (EOR) has been widely considered as a means for reducing anthropogenic CO$_2$ emissions to the atmosphere. However, rather than treating CO$_2$ as a waste fluid in need of disposal, we propose that it could also be used as a working fluid in geothermal energy capture, as previous studies (e.g., [Randolph and Saar, 2010; 2011b]) suggest it transfers heat more efficiently than water. Therefore, using CO$_2$ as a subsurface geothermal working fluid may permit use of lower temperature and lower permeability geologic formations than those currently deemed economically viable. Furthermore, CPG reduces electricity-related CO$_2$ emissions through both geologic CO$_2$ sequestration and displacement of hydrocarbon-based power.

CPG systems involve pumping CO$_2$ into deep, naturally porous and permeable geologic formations where the CO$_2$ displaces native reservoir fluid and is heated by the natural in-situ heat and the background geothermal heat flux. A portion of the heated CO$_2$ is piped to the surface,
providing energy for electricity production or direct heat utilization, before being returned to the subsurface. The injected CO\textsubscript{2} is permanently stored via geologic sequestration.

Traditional water-based geothermal development requires three geologic conditions are met:  1) significant amounts of water, 2) a permeable formation to permit water extraction/reinjection, and 3) sufficient subsurface temperatures. Enhanced geothermal systems (EGS) seek to artificially generate Condition 2 and supply (water-based EGS) or avoid (CO\textsubscript{2}-based EGS, e.g. [Brown, 2000; Pruess, 2006]) Condition 1, thereby expanding geothermal heat mining prospects. CPG systems, in addition to avoiding Condition 1, lower minimum thresholds of economically and technologically viable subsurface temperatures (Condition 3), as the high mobility of CO\textsubscript{2} enhances heat extraction efficiency.

Existing literature [Randolph and Saar, 2010, 2011b] has noted that the high mobility of CO\textsubscript{2} compared to water at the geologic conditions of interest for natural-reservoir-based geothermal development should permit CPG development in reservoirs with permeabilities lower than are viable for water-based geothermal (Condition 2, previous paragraph). Here, we explore geothermal heat extraction from naturally permeable, porous geologic formations as a function of reservoir permeability and subsurface heat exchange fluid.

Numerical simulation methodology
The purpose of the investigation detailed here is to isolate the effects of permeability and choice of subsurface heat extraction fluid on natural-reservoir-based geothermal energy production. To
accomplish a comparison of reservoir behavior between fluids, numerous assumptions and simplifications to the system are incorporated into numerical simulations.

First, we assume sufficient geologic formation injectivity/ productivity in the immediate neighborhood of wells (bottom hole) for the specified injection/production rates. Though injectivity/ productivity are important considerations, the current focus is on reservoir-scale properties. Insufficient near-well-bottom-hole properties could be addressed in part through the use of limited hydraulic stimulation or horizontal wells with long sections open to the reservoir.

We simulate operation of geothermal reservoirs containing CO$_2$, pure water (henceforth called “water”), or 20% mass fraction NaCl brine (henceforth called “brine”) over a variety of reservoir permeabilities, from $5 \times 10^{-16}$ to $5 \times 10^{-12}$ m$^2$ (see, e.g., [Finley, 2005; Steadman et al., 2006] for sample CO$_2$ sequestration reservoirs with permeabilities covering this range and fluid compositions similar to this brine). In each numerical model, only one fluid occupies the pore space, analogous to previous CPG studies [Randolph and Saar, 2010, 2011b] and CO$_2$-based EGS studies [Pruess, 2006, 2008]. Thus, in the case of CO$_2$ working fluid, the presence of subsurface CO$_2$ is assumed (naturally or from previous injection), and while displacement of native fluid – such as water, brine, or hydrocarbons – is of interest, it is beyond the scope of the present study. All simulations utilize the reservoir simulator TOUGH2 [Pruess, 2004] with equation-of-state module ECO2N [Pruess, 2005].

Of particular interest are low-temperature geothermal resources; as such, a subsurface system initial temperature of $T = 100$ °C, often considered the lower limit for geothermal electricity production [e.g., Hulen and Wright, 2001], is chosen. In a region with low-to-moderate geothermal gradients (30-35 °C/km), $T = 100$ °C corresponds to a reservoir depth of 2.5 km, dependent upon local mean annual surface temperature and fluid/rock thermal conductivity. At such low reservoir temperatures and heat flow rates, it is reasonable to assume approximately hydrostatic pressures [Sanyal et al., 2007]. See Table 1 for a list of formation and model parameters, which are generally consistent with previous publications concerning CPG [Randolph and Saar, 2010, 2011a, 2011b]. With such low formation temperatures, the geothermal power system is taken to be a binary system [Sanyal et al., 2007].

<table>
<thead>
<tr>
<th>Parameters: Base Case</th>
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<tbody>
<tr>
<td><strong>Geologic formation</strong></td>
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<tr>
<td>Formation map-view area</td>
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<tr>
<td>Thickness</td>
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<td>Permeability, $k$</td>
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<td>Porosity</td>
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<td>Rock grain density</td>
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<td>Rock specific heat</td>
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<td>Thermal conductivity</td>
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<td>Heat extraction rate</td>
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<tr>
<th><strong>Formation initial conditions</strong></th>
<th><strong>Formation boundary conditions</strong></th>
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<tbody>
<tr>
<td>Fluid in pore spaces</td>
<td>All CO$_2$, H$_2$O, or brine</td>
</tr>
<tr>
<td>Temperature</td>
<td>100 °C</td>
</tr>
<tr>
<td>Pressure</td>
<td>250 bar</td>
</tr>
</tbody>
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Table 1: Summary of parameters used in base case models. Base case parameters correspond, in general, to parameters utilized in previous studies [Randolph and Saar, 2010, 2011a, 2011b]. The base case simulations were utilized to determine mass-flow rate for each fluid at $k = 5 \times 10^{-14}$ m$^2$; this mass-flow rate was then fixed as permeability was varied. See text for additional details.
Long-term fluid behavior in injection and production wells, once rock surrounding the wells has achieved near-equilibrium with well fluid temperatures, can be approximated as isenthalpic [Pruess, 2006]. Accounting for isenthalpic expansion/compression, i.e. Joule-Thompson cooling/heating, is primarily important in CO₂ simulations (Figure 2). The temperature, $T$, and pressure, $P$, profiles for CO₂ in the injection well are calculated by Newtonian iteration starting from $T,P$ values at the surface. Fluid injection surface $T$ is set to 22 °C, which is 10 °C higher than the average annual atmospheric (i.e., power system heat rejection) temperature in St. Paul, MN [NCDC]. This is a conservative assumption for heat rejection efficiency of binary geothermal systems [DiPippo, 2007]. Furthermore for CO₂, injection surface pressure is set to 10 bar above saturation pressure (60.0 bar) at injection wellhead temperature, ensuring single phase conditions in surface equipment (of particular value should the reader wish to compare this binary power system with a direct CO₂ turbine system). Because of the low compressibility/expansivity of water and brine, they are assumed to undergo isothermal well flow [Pruess, 2006].

![Figure 2: Isenthalpic CO₂ flow in geothermal injection and production wells. Because CO₂ is a relatively compressible supercritical fluid at the temperature and pressure conditions of interest, it compresses/ heats upon injection and expands/ cools during production. Water and brine (not shown), in contrast, are relatively incompressible liquids and experience essentially isothermal well flow.](image)

For simplicity, we assume constant fluid production temperature, a reasonable approximation for the first ten years of power plant operation at the specified reservoir and injection/production conditions (see Figure 3 of Randolph and Saar [2011b]). Moreover, we ignore the pressure drop through the surface equipment. While important, this will be explored in future analyses. Note that in certain CPG systems, a throttling valve could be used to sufficiently decrease pressure between injection and production wellheads, whereas in water/brine and other CPG cases (e.g., very low reservoir permeability), additional pumping may be needed.

We account for injection and production pumping power using the approximation given in the US Department of Energy Geothermal Electricity Technology Evaluation Model (GETEM) [Entingh, 2006], where pumping power = (total flow) x ($\Delta P/\rho$) x (pump efficiency). Here, $\Delta P$ is the required pressure rise to ensure the total flow rate, and $\rho$ is fluid density. Pump efficiency is set conservatively high, to 0.9 (modified from Sanyal et al., [2007]). In CPG simulations, pumping power is assumed to be zero if the production wellhead pressure is higher than the injection wellhead pressure (i.e., a thermosyphon exists). Assuming use of downhole shaft pumps (as opposed to electric submersible pumps, which are not yet in extensive operation), pump depth is limited to 450 m [Sanyal et al., 2007]. Thus, for water and brine models, the
assumption of approximately hydrostatic reservoir conditions imposes a minimum pressure of ~205 bar at the production well bottom hole such that the fluid will reach the downhole production pump. In simulations, the production bottom hole pressure is not permitted to fall below 210 bar and any additional fluid-driving pressure differential between injection and production wells must come from the injection side.

Reservoir thermal energy extraction rate, $H$, is calculated from specific enthalpy difference between produced, $h$, and injected, $h_o$, fluids, and the production fluid mass rate, $Q$, given as $H = Q(h − h_o)$. Electricity production rate, $E$, is then calculated by multiplying $H$ by the Carnot efficiency – calculated using fluid wellhead temperature and the previously-stated average annual surface temperature (12 °C) – and by a 50% mechanical system efficiency (modified after Sanyal and Butler [2005]).

Finally, there are many means that could be employed to compare the CO$_2$, water, and brine systems. For instance, we could use the same fixed bottom hole pressure difference between injection and production wells for all fluids, as in previous studies [Pruess, 2006; Randolph and Saar, 2010, 2011b]. Alternatively, we could set the production mass flow rate or the binary system power output to be the same for all fluids. However, in order to isolate the effects of reservoir permeability, $k$, from differences in mobility (inverse kinematic viscosity) and heat capacity of the fluids, we choose to fix the reservoir heat energy extraction rate between fluids for a given reservoir permeability (see Randolph and Saar [2011b] for additional information on fluid mobility differences and consequences for reservoir heat extraction). To determine a heat extraction rate to use in comparisons, we start (for consistency with previous literature [Randolph and Saar, 2010, 2011b]) with the base case model parameters given in Table 1 (note, $k = 5 \times 10^{-14}$ m$^2$). Beginning with the CO$_2$ case, fluid flow is driven by a 20 bar pressure drop through the reservoir. The CPG heat extraction rate is then determined. For water and brine simulations at the same permeability the pressure drop through the reservoir is adjusted to match the CO$_2$ heat extraction rate. The pressure drops specify a mass-flow rate for each fluid, which is fixed as permeability is varied.

Note that these simulations do not necessarily optimize power plant electricity production for each permeability and fluid. For example, a CPG reservoir with high permeability (e.g., $5 \times 10^{-12}$ m$^2$) would likely have a power system designed to operate at higher fluid mass-flow rates than that used in this set of simulations. However, in order to compare various reservoir fluids over a variety of permeabilities, fluid mass-flow rates are fixed.

**Results:** **Electricity production efficiency versus reservoir permeability**

Figure 3 presents geothermal electricity production efficiency versus reservoir permeability for CO$_2$, water, and brine subsurface working fluids. Electricity production efficiency is defined as the net electricity production rate, $E_{net}$, divided by the total heat energy extraction rate, $H$. $E_{net}$ is the total electricity production rate, $E$, minus injection/ production pumping power requirements.
For reservoir permeabilities below approximately $2 \times 10^{-14}$ m$^2$, CO$_2$ provides clearly higher electricity production efficiency than both water and brine (see (B) in Figure 3). For larger permeabilities of $k > 2 \times 10^{-14}$ m$^2$, pure water, and for $k > 5 \times 10^{-14}$ m$^2$ (A in Figure 3), brine is more efficient than CO$_2$. At moderate-to-low permeabilities of about $10^{-16} < k < 10^{-14}$ m$^2$, CO$_2$’s high mobility compared to water and brine [Randolph and Saar, 2011b] is particularly advantageous as it minimizes pumping power requirements while permitting high mass flow rates. Within this latter permeability range, some $k$ values are so low that net electricity production with pure water, let alone brine, is not possible, while CO$_2$’s efficiency is hardly diminished (Figure 3). However, at higher permeabilities, the relatively high heat capacity and low compressibility of liquid water and brine, compared to CO$_2$, result in water and brine having moderately more favorable electricity production efficiencies. At very high permeabilities of about $k > 5 \times 10^{-13}$ m$^2$, pumping power (for water and brine) nears zero (while CO$_2$ does not require pumping due to a strong thermosyphon effect) and electricity production efficiency ceases changing with $k$.

These results are reasonable in light of the common observation that significant advective heat transfer by water (or brine) appears to require minimum permeabilities of $5 \times 10^{-17} < k_{\text{min}} < 10^{-15}$.
m² (e.g., Manning and Ingebritsen [1999] and Saar [2011]), given the hydraulic head gradients, kinematic water viscosities, and water heat capacities at temperatures and pressures typically of interest. Hence, Figure 3 shows how supercritical CO₂’s differing kinematic viscosity (or mobility), heat capacity, and compressibility combine to provide improved geothermal heat extraction – and ultimately electricity production – efficiencies at permeabilities at or below $k_{\text{min}}$ for water.

In order to explore the effects of permeability on electricity production efficiency over a variety of temperature and pressure conditions, simulations were executed at several points along two different geothermal gradients, the results of which are given in Figure 4. In panels [A], [B], and [C] the figure, a geothermal gradient of 35 °C/km (with 12 °C as the average annual surface temperature) is utilized, representing a moderate geothermal heat flow. Note that panel [B] provides the same results as Figure 3, allowing comparison with other panels. Figure 4 panels [D], [E], and [F] represent a geothermal gradient of 60 °C/km, consistent with a relatively high geothermal heat flow rate. Depending on $T$, $P$, CO₂ provides higher electricity production efficiency than water at permeabilities as high as $2 \times 10^{-13}$ m² (Figure 4 panel [A]). Similarly, CO₂ provides higher electricity production efficiency than brine at permeabilities as high as $4 \times 10^{-13}$ m² (Figure 4 panel [A]) or as low as $2 \times 10^{-14}$ m² (panel [C]).

As geothermal development in sedimentary basins progresses, it is likely that at the depths required to achieve sufficient temperatures for economical geothermal development, permeability may be well below $2 \times 10^{-14}$ m² as a results of 1) compaction (of sediments) and 2) hydrothermal alteration causing clogging of pore space (e.g., see Finley [2005] and Steadman et al., [2006] for $k$ of deep sedimentary basins). Moreover, in crystalline rocks, $k$ can be small even at shallower depths. Thus, the results of this investigation are relevant for CPG-type development in sedimentary basins as well as moderately-permeable EGS in crystalline rocks.

**Conclusions**

Previous studies (Randolph and Saar, 2010, 2011b) have shown that CO₂-plume geothermal (CPG) systems provide higher geothermal heat extraction rates from naturally permeable, porous geologic formations than traditional water-based reservoir geothermal operations, even at low subsurface temperatures. The work presented here demonstrates that CO₂ is particularly beneficial as a geothermal heat exchange fluid in moderate-to-low permeability ($k < 2 \times 10^{-14}$ m²) formations. Such geologic reservoirs exist worldwide and are under consideration for geologic CO₂ sequestration (e.g., [Finley, 2005; Metz et al., 2005; Steadman et al., 2006]).
Figure 4:
Future work will explore the geothermal electricity production efficiency of CO₂, water and brine accounting for more optimization of the power cycle. At low resource temperatures \((T < 150 \, ^{\circ}\text{C})\), water- or brine-based geothermal operations are limited to binary power plants, often utilizing a form of Organic Rankine Cycle \([GEA, 2010]\). However, because of its low critical temperature \((31.1 \, ^{\circ}\text{C} \text{ at } 73.8 \text{ bar})\), CO₂ could be used directly in a turbine (tolerable levels of contaminants in the CO₂ will also be examined). Potentially, such a direct system would permit significantly higher thermal energy utilization efficiency than accounted for with the simple correlations in the current study. For instance, in base CO₂ case of the current study \((T = 100 \, ^{\circ}\text{C},\, P = 250 \, \text{bar},\, k = 5\times10^{-14} \, \text{m}^2\) ), the thermal electricity production rate \(E_{\text{net}}\) is calculated to be 3,664 kW and the thermal utilization efficiency is 8.4%. In comparison, work, \(W\), produced from a direct system is given by \(W = (\text{total mass flow}) \times (\Delta P/\rho)\), where \(\Delta P\) is the pressure difference between injection and production wells (at wellheads) and \(\rho\) is fluid density. Assuming 93% turbine efficiency and 90% system efficiency \([Dostal et al., 2004]\), \(E_{\text{net}} = 4,170\) kW and the thermal utilization efficiency is 9.6% for the direct, base case CO₂ system. At higher resource temperatures and pressures, where the wellhead pressure difference may be much larger, the direct system efficiency may be proportionally even larger.

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