Combining geothermal energy capture with geologic carbon dioxide sequestration

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Geothermal energy offers clean, renewable, reliable electric power with no need for grid-scale energy storage, yet its use has been constrained to the few locations worldwide with naturally high geothermal heat resources and groundwater availability. We present a novel approach with the potential to permit expansion of geothermal energy utilization: heat extraction from naturally porous, permeable formations with CO₂ as the injected subsurface working fluid. Fluid-mechanical simulations reveal that the significantly higher mobility of CO₂ compared to water, at the temperature/pressure conditions of interest makes CO₂ an attractive heat exchange fluid. We show numerically that, compared to conventional water-based and engineered geothermal systems, the proposed approach provides up to factors of 2.9 and 5.0, respectively, higher geothermal heat energy extraction rates. Consequently, more regions worldwide could be economically used for geothermal electricity production. Furthermore, as the injected CO₂ is eventually geologically sequestered, such power plants would have negative carbon footprints.


1. Introduction

[1] Geothermal energy offers clean, renewable, reliable electric power with no need for grid-scale energy storage, yet its use has been constrained to the few locations worldwide with naturally high geothermal heat resources and groundwater availability. We present a novel approach with the potential to permit expansion of geothermal energy utilization: heat extraction from naturally porous, permeable formations with CO₂ as the injected subsurface working fluid. Fluid-mechanical simulations reveal that the significantly higher mobility of CO₂, compared to water, at the temperature/pressure conditions of interest makes CO₂ an attractive heat exchange fluid. We show numerically that, compared to conventional water-based and engineered geothermal systems, the proposed approach provides up to factors of 2.9 and 5.0, respectively, higher geothermal heat energy extraction rates. Consequently, more regions worldwide could be economically used for geothermal electricity production. Furthermore, as the injected CO₂ is eventually geologically sequestered, such power plants would have negative carbon footprints.

2. CO₂-Plume Geothermal (CPG)

[4] CPG involves injecting supercritical CO₂ into deep, naturally porous, permeable geologic reservoirs overlain by low-permeability caprock (Figure 1), formations often prevalent worldwide [e.g., IPCC, 2005]. There, the CO₂ displaces native formation fluid (e.g., brine or hydrocarbons), as in standard CO₂ sequestration or enhanced oil recovery (EOR), and is heated by the natural in-situ heat and geothermal heat flux. A portion of the heated CO₂ is piped back to the surface and sent through an expansion device, powering an electrical generator, or a heat exchanger to provide heat for direct use and/or binary power systems. The CO₂ is then re-injected into the reservoir; long-term, all injected CO₂ is stored.

[5] As demonstrated here, CPG systems are capable of achieving improvements in heat extraction efficiencies well above those accomplished by replacing water with CO₂ as the working fluid in EGS. The CPG approach has only become feasible of late, due to planned (and partially implemented) large-scale geologic CO₂ sequestration in natural reservoirs worldwide. Discussion of the challenges and opportunities of CO₂ sequestration or EOR, though inherent to CPG, are reserved for the extensive literature [e.g., Hitchon, 1996; Bachu, 2003; IPCC, 2007]. Existing preliminary research on CO₂-based EGS [Pruess, 2006, 2008; Atrens et al., 2009], though a recently devised method itself, provides context to determine the feasibility of the new CPG approach. Hence, we focus our investigation on

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comparing CPG with CO₂- and water-based EGS, and with conventional water-based geothermal reservoir systems.

3. Model Characteristics and Methods

[6] Model parameters are summarized in Tables 1 and 2. A subsurface system initial temperature of \( T = 100^\circ\text{C} \) is chosen for base-case models, as it is often considered the lower limit for geothermal electricity production [e.g., Hulen and Wright, 2001]. In comparison, \( T = 150^\circ\text{C} \) is more typical for water-based geothermal systems, as \(~90\%\) of the US geothermal electrical capacity operates on higher-temperature (\( T > 150^\circ\text{C} \)) dry and flash-steam systems rather than low-temperature (\( 100 < T < 150^\circ\text{C} \)) binary systems (Geothermal Energy Association, unpublished data, 2010, available at http://geo-energy.org/plants.aspx; International Energy Agency, unpublished data, 2010, available at http://www.iea.org). In a region of moderate heat flow (here characterized by a geothermal gradient of 30–35°C/km), \( 100^\circ\text{C} \) corresponds to a formation depth of \(~2.5\) km, depending on the local mean annual surface temperature and fluid-rock thermal conductivity. Fluid injection/production rates are determined by specifying downhole injection and production pressures 10 bars higher and lower, respectively, than formation pressure. The presence of subsurface CO₂ is assumed (naturally or from previous injection) and no other fluid occupies the pore space, analogous to CO₂-based EGS studies [Pruess, 2006, 2008]. While displacement of native fluid is of interest, it is beyond the scope of the present study. All simulations utilize the well-verified reservoir simulator TOUGH2 [Pruess, 2004] with equation-of-state module ECO2N [Pruess, 2005]. Conduction of heat between the domain and confining beds, a minor contribution to model heat budget [Pruess, 2008], is approximated using the semi-analytic heat exchange method in TOUGH2 [Pruess et al., 1999].

[7] To ensure that models constructed for the present study function correctly, the EGS models and results of Pruess [2006] were first reproduced (not shown). The symmetry of the employed five-spot computational grid reduces simulation requirements to 1/8th of the system domain (Figure 2, inset, gridded region). In EGS models, fracture/matrix heat exchange is accomplished via the multiple-interacting continua method [Pruess and Narasimhan, 1985]. Heat extraction rate, \( H = Q(h - h_\text{ref}) \), and fluid mass flow rate, \( Q \), are monitored at a production well; \( h \) and \( h_\text{ref} \) are specific enthalpy of the produced and injected fluids, respectively.

[8] A representative value for permeability, \( k \), of hydraulically stimulated rock (in EGS) of \( 2.5 \times 10^{-14} \text{ m}^2 \) is determined.
by averaging the reported values from EGS field sites – Soultz, France: $6 \times 10^{-14}$ m$^2$ [Evans et al., 2005; Shapiro et al., 1999]; Ogachi, Japan: $10^{-15}$ to $10^{-14}$ m$^2$ [Tester et al., 2006] – together with system-scale $k_{\text{EGS}} = 1.1 \times 10^{-14}$ m$^2$, calculated via a network model from individual fracture permeabilities [Randolph and Saar, 2010].

4. Energy Recovery

[9] Figure 2 presents temperatures from injection to production well after 10 simulated years of heat recovery, providing an intermediate snapshot of system behavior and illustrating heat extraction differences among CPG and CO$_2$-based EGS cases. Here, all simulations are performed with the same permeability ($5 \times 10^{-14}$ m$^2$, calculated in Randolph and Saar [2010]) to ensure identical mass flow rates. As noted in Section 3, $k_{\text{EGS}}$ is expected to be less than that of reservoir systems. Thus, results depicted in Figure 2 are conservative; Figure 3 includes results for $k_{\text{EGS}} < 5 \times 10^{-14}$ m$^2$. Three EGS cases are considered, corresponding to fracture spacings of 70 m (primary grid block side length), 140 m, and 210 m. Such discrete fracture networks provide reasonable approximations of principal fluid flow conduits and heat extraction from fracture-dominated systems, as percolation theory, principal path analysis, and field tests often show that while systems may contain dense fracture networks, very few fractures accommodate the majority of fluid flow [e.g., Berkowitz, 2002].

[10] In the CPG case, temperature at the production well remains closer to the initial system temperature (100°C) than in any EGS case (Figure 2), permitting more prolonged heat use in CPG. Furthermore, EGS production temperature decreases with increasing fracture spacing. These results indicate more thorough heat-sweeping capabilities of the CPG system than fractured formations, a consequence of the CO$_2$ being in contact with a larger specific surface area of host rock or sediment in CPG.

[11] Time series of geothermal heat energy extraction rates are provided in Figure 3a. All rates are given for the full, 5-well domain. Two values for $k_{\text{EGS}}$ are considered: $5 \times 10^{-14}$ m$^2$, to allow direct comparison with reservoir-system simulations, and $2.5 \times 10^{-14}$ m$^2$, more indicative of actual EGS implementations (Section 3). Heat extraction rates decrease with time as formation heat is depleted and production temperatures decrease. EGS models with lower permeabilities result in smaller mass flow rates, producing lower heat extraction rates, though slower formation cooling, than EGS with similar fracture spacing and higher permeability.

[12] Fluid mobility - density divided by dynamic viscosity (i.e., inverse kinematic viscosity) - describes a fluid’s tendency to preserve momentum. Hence, despite the lower heat capacity of CO$_2$ than water, 2.20 versus 4.16 J/g/K at 100°C and 250 bar (NIST), CO$_2$’s markedly higher mobility (Tables 3 and 4) permits higher fluid mass flow rates and, thus, higher heat extraction rates at a given reservoir $k$ and reduces the minimum $k$ above which heat advection tends to dominate over conduction [Saar, 2011]. Moreover, a low natural-reservoir $k = 5 \times 10^{-14}$ m$^2$ (conservative average calculated from several CO$_2$ storage sites [Finley, 2005; Steadman et al., 2006]) was utilized, suggesting that for actual implementation sites, CPG heat extraction rates could be greater.

[13] Figure 3b compares CPG, water-based reservoir, and water- and CO$_2$-based EGS heat extraction potentials for a variety of formation temperatures and pressures. A conservative EGS fracture spacing of 70 m is specified, which represents the investigated spacing with heat-sweeping characteristics most similar to reservoir (CPG) cases, and $k_{\text{EGS}} = 2.5 \times 10^{-14}$ m$^2$. CPG systems provide greater heat extraction rates compared to water-based systems (both reservoir and EGS) as temperature and pressure decrease, suggesting the CPG approach is particularly useful in, but not restricted to, relatively shallow geologic formations. Minimum depths are required, however, to ensure adequate subsurface temperatures and that CO$_2$ is supercritical.

5. Implications for Geothermal Development

5.1. Expansion of the Geothermal Resource Base

[14] Traditional water-based geothermal development requires three geologic conditions: 1) significant amounts of water, 2) a permeable formation to permit water extraction/ reinjection, and 3) sufficient subsurface temperatures. EGS seeks to artificially generate Condition 2 and supply (water-based EGS) or avoid (CO$_2$-based EGS) Condition 1, thereby

Table 2. Parameters of Cases for Exploration of Parameter Space

<table>
<thead>
<tr>
<th>Case Number</th>
<th>Permeability (Reservoir/EGS)</th>
<th>Formation Pressure</th>
<th>Formation Temperature</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>$5 \times 10^{-14}$ / $2.5 \times 10^{-14}$ m$^2$ a</td>
<td>250 bar$^a$</td>
<td>120°C</td>
</tr>
<tr>
<td>2</td>
<td>$5 \times 10^{-14}$ / $2.5 \times 10^{-14}$ m$^2$ a</td>
<td>250 bar$^a$</td>
<td>140°C</td>
</tr>
<tr>
<td>3</td>
<td>$5 \times 10^{-14}$ / $2.5 \times 10^{-14}$ m$^2$ a</td>
<td>200 bar</td>
<td>100°C</td>
</tr>
<tr>
<td>4</td>
<td>$5 \times 10^{-14}$ / $2.5 \times 10^{-14}$ m$^2$ a</td>
<td>300 bar</td>
<td>100°C</td>
</tr>
<tr>
<td>5</td>
<td>$5 \times 10^{-14}$ / $2.5 \times 10^{-14}$ m$^2$ a</td>
<td>250 bar$^a$</td>
<td>100°C</td>
</tr>
</tbody>
</table>

$^a$Parameter is the same as in the base cases. Cases 1–4 apply to CPG, CO$_2$-based EGS, H$_2$O reservoir, and H$_2$O-based EGS. Case 5 applies only to CO$_2$-based EGS.
expanding geothermal heat mining prospects. In comparison, CPG provides an alternative working fluid (avoiding Condition 1) with high mobility compared to water (Tables 3 and 4), thus expanding the range of usable natural-formation permeabilities (Condition 2). Similarly, CO₂ lowers minimum thresholds of economically and technologically viable subsurface temperatures (Condition 3), as its high mobility enhances heat extraction efficiency.

[15] Figure 4 quantifies the expansion of subsurface regions that may become viable for geothermal power production in the contiguous US when CO₂ rather than water is used as the reservoir-based (i.e., CPG) heat extraction fluid; similar expansions may be feasible worldwide. Although the technology exists to utilize water-based geothermal resources at temperatures <100°C, approximately 90% of US installed capacity uses dry-steam or flash power systems, which rely on subsurface temperatures >150°C. Our models indicate that a traditional water-based reservoir system, installed in a single five-spot pattern (Figure 2, inset), at 150°C and 2.5 km depth with \( k = 5 \times 10^{-14} \text{ m}^2 \) would, over 25 years, extract on average 46 MW of thermal energy, given base-case parameters (Tables 3 and 4). Applying a Carnot calculation with an annual average heat rejection temperature of 10°C and assuming a power system efficiency of 50% (modified after Sanjay and Butler [2005]), this translates to 5.2 MW of electrical generation. Our simulations show that a CPG system with identical parameters results in the same electrical production with geologic temperatures of only 98.2°C. Applying similar considerations, a water reservoir system at 100°C is required to provide the same electric power as a CPG system at only 65.8°C. Note: as in traditional geothermal development, several CPG systems could be installed at a given site.

[16] The just-discussed subsurface temperature pairs of 150°C/98.2°C (Figure 4a) and 100°C/65.8°C (Figure 4b) at 2.5 km depth illustrate the expanded regions of economically viable geothermal heat mining, should CO₂ be utilized rather than water and assuming suitable reservoirs exist. Figure 4 illustrates that while only black-shaded regions are viable for water-based reservoir geothermal systems, both gray- and black-shaded regions could be viable for CPG implementations. These comparisons do not include differences in Joule-Thomson heating/cooling in wells between CO₂ and water [Pruess, 2006]. Nonetheless, the CPG-viable regions may be considered conservative as they do not account for efficiency benefits when using CO₂, rather than water, in a power cycle (e.g., higher-than-atmospheric operating pressure leaving CO₂ turbines compared to near-vacuum pressure leaving steam turbines [Atrens et al., 2009]). Moreover, CO₂ freezes at temperatures significantly below 0°C, and thus in cool climates, the heat rejection temperature of CPG can be much lower and the electricity production potential, higher, than calculated. Also, the potential for a CO₂ thermosyphon [Atrens et al., 2009] and associated, perhaps significant, reduction in pumping costs are not examined here.

5.2. Additional Implications of CPG Systems

[17] Sales of CPG-produced energy could help offset the cost of CO₂ capture and storage; alternatively, in a carbon market, revenue from sequestration could enhance the competitiveness of CPG electricity [Randolph and Saar, 2011].

[18] Next, water-based EGS is confronted with challenges of loss and reactivity of injected water, as well as induced seismicity. EGS test sites have experienced water losses of up to 12% or more [Tester et al., 2006]. Clean, potable water is often limited, making such loss undesirable. In contrast, “loss” of injected CO₂ (i.e., sequestration) in saline - and thus unusable - formations would be favorable. Furthermore, pure-phase CO₂, or CO₂ with little dissolved water, should be markedly less reactive than water in formations of interest for geothermal development [Brown, 2000; Atrens et al., 2009], limiting mineral dissolution/precipitation and “short-circuiting” of fluid flow pathways. Formation plugging is also less likely in a CPG system than in EGS, as percolation theory indicates that fluid flow pathways are more diverse and difficult to interrupt in a 3D porous medium than 2D or even 3D fracture systems [e.g., Berkowitz, 2002].
Table 3. Results of Average Heat Extraction Rates (MW)\(^a\)

<table>
<thead>
<tr>
<th>Case Number</th>
<th>CPG</th>
<th>H(_2)O Reservoir</th>
<th>CO(_2)-Based EGS</th>
<th>H(_2)O-Based EGS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case</td>
<td>47.0</td>
<td>17.4</td>
<td>26.2</td>
<td>9.2</td>
</tr>
<tr>
<td>1</td>
<td>58.6</td>
<td>23.2</td>
<td>32.8</td>
<td>12.4</td>
</tr>
<tr>
<td>2</td>
<td>68.8</td>
<td>29.3</td>
<td>38.4</td>
<td>15.7</td>
</tr>
<tr>
<td>3</td>
<td>52.4</td>
<td>17.2</td>
<td>30.2</td>
<td>9.1</td>
</tr>
<tr>
<td>4</td>
<td>43.0</td>
<td>17.7</td>
<td>23.5</td>
<td>9.3</td>
</tr>
<tr>
<td>5</td>
<td>n.a.</td>
<td>n.a.</td>
<td>45.8</td>
<td>n.a.</td>
</tr>
</tbody>
</table>

\(^a\)Averages for 25 years of working-fluid injection/production and resultant heat energy recovery. Cases 1–4 apply to CPG, CO\(_2\)-based EGS, H\(_2\)O reservoir, and H\(_2\)O-based EGS. Case 5 applies only to CO\(_2\)-based EGS.

Table 4. Results of Ratios of Average Heat Extraction Rates (HE), Mobilities (M), and Mass Flow Rates (MF)\(^a\)

<table>
<thead>
<tr>
<th>Case Number</th>
<th>CPG to H(_2)O Reservoir</th>
<th>CPG to CO(_2)-Based EGS</th>
<th>CPG to H(_2)O-Based EGS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base case</td>
<td>2.7</td>
<td>1.8</td>
<td>1.9</td>
</tr>
<tr>
<td>1</td>
<td>2.4</td>
<td>1.8</td>
<td>1.9</td>
</tr>
<tr>
<td>2</td>
<td>2.3</td>
<td>1.8</td>
<td>1.9</td>
</tr>
<tr>
<td>3</td>
<td>2.9</td>
<td>1.8</td>
<td>1.8</td>
</tr>
<tr>
<td>4</td>
<td>2.5</td>
<td>1.8</td>
<td>1.8</td>
</tr>
<tr>
<td>5</td>
<td>n.a.</td>
<td>n.a.</td>
<td>n.a.</td>
</tr>
</tbody>
</table>

\(^a\)Averages for 25 years of working-fluid injection/production and resultant heat energy recovery. Cases 1–4 apply to CPG, CO\(_2\)-based EGS, H\(_2\)O reservoir, and H\(_2\)O-based EGS. Case 5 applies only to CO\(_2\)-based EGS.

Figure 3. Time series of (a) geothermal heat extraction rates and (b) ratios of rates. CPG benefits over water-based systems are most pronounced at lower temperatures and pressures (i.e., shallower systems). Legend columns denote: system type, fracture spacing if applicable, system permeability (Figure 3a); system type, temperature, pressure (Figure 3b). In Figure 3b, reservoir system \(k = 5 \times 10^{-14} \text{ m}^2\) and \(k_{\text{EGS}} = 2.5 \times 10^{-14} \text{ m}^2\) (see main text).
as the subsurface working as the subsurface geothermal heat extraction fluid (see
Pruess sequestration.
Acknowledgments.
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Expansion of viable geothermal regions using CPG. Temperature contours at 2.5 km depth illustrate the esti-
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in geological media in response to climate change,
[10x-8]Figure 4. Expansion of viable geothermal regions using CPG. Temperature contours at 2.5 km depth illustrate the esti-
ated expansion of regions viable for electricity production (if naturally permeable, porous reservoirs overlain by low-
permeability caprocks exist), when replacing water with CO₂ as the subsurface geothermal heat extraction fluid (see
main text), from dark-shaded to both dark- and gray-shaded regions. Maps were created using geothermal heat flow
data from the Southern Methodist University heat flow database (2008, http://smu.edu/geothermal) together with the
cdo.ncdc.noaa.gov).

[19] Finally, meeting electricity demand by balancing baseload and peak power requirements is a challenge for
expanding the use of renewable energies. Wind and solar are critical elements of the renewable energy landscape, but
they have difficulty fulfilling baseload demand given the inconsistent nature of their energy sources. Geothermal can
provide power both continuously and intermittently, helping meet baseload requirements or contributing to peak
demands. Thus, alternative geothermal technology, such as CPG, that expands our ability to capture geothermal energy
beyond conventionally-viable regions, will become increas-
ingly important.

6. Conclusions
[20] We suggest that CO₂-plume geothermal (CPG) provides viable geothermal energy resources for electricity pro-
duction, even in regions with relatively low geothermal temperatures and heat flow rates, where suitable reservoirs
exist. Early-stage studies by several authors have indicated high potential for EGS with CO₂ as the subsurface working
fluid [Brown, 2000; Pruess, 2006]. The work presented here, however, demonstrates that under a broad range of
conditions, CPG results in significantly higher heat mining rates than even CO₂-based EGS, let alone traditional water-
based reservoir or EGS methods, while simultaneously stor-
ing CO₂.

[21] We recognize that inherent in the CPG approach are the challenges (and rewards) of geologic CO₂ sequestration.
However, sequestration, both in saline aquifers and during Enhanced Oil Recovery (EOR), is extensively discussed in the
literature and already occurring worldwide. Future work will investigate native formation fluid displacement by injected
CO₂, fluid-mineral reactions, and upconing of the CO₂-brine interface. Adding geothermal energy capture to geologic CO₂
sequestration, i.e., the CPG approach, could improve the economic viability of sequestration by providing electricity for
CO₂ injection and/or energy sales [Randolph and Saar, 2011]. Simultaneously, opportunities for renewable electricity pro-
duction could be expanded into regions far beyond those deemed economical for water-based geothermal.

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