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Benefits of Using Active Reservoir Management During CO_2-Plume Development for CO_2-Plume Geothermal (CPG) Systems

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ABSTRACT

Carbon capture and storage (CCS) is a critical technology in reducing CO_2 emissions into the atmosphere, operating by permanently storing captured CO_2 in geologic formations. This geologically stored CO_2 can be utilized in a geothermal power system, known as CO_2-Plume Geothermal (CPG), which utilizes CO_2 as the heat extraction fluid in an open-loop power cycle as part of a carbon capture, utilization, and storage (CCUS) process. However, the injection of CO_2 into sedimentary basins can increase the reservoir pressure due to the displacement and compression of the native brine, particularly during the CO_2 plume development phase for a CPG system. This can increase the risk of CO_2 leakage and the formation of fractures in the reservoir and require additional pumping, and thus power consumption, to inject the CO_2. Active CO_2 Reservoir Management (ARM) can reduce the pressure buildup during CO_2 injection by producing brine to the surface through the CPG production wells. Brine production during plume development can reduce the CO_2 injection pressure and shorten the plume development period, while simultaneously producing hot brine at the surface that can be used to produce electricity (or heat) and/or fresh water by employing enhanced water recovery (EWR) methods.

Here, we present how a CPG system, can be combined with ARM to manage reservoir pressures during CO_2 plume development, to produce electricity using the hot brine and reduce the reservoir development time for a CPG system. Our investigated system is comprised of a single reservoir, with a vertical injection well and a horizontal production well, vertical wells connecting them to the surface, and a surface power plant. We found ARM reduced the breakthrough time by 4% to 7%, reduced the overpressure by 20% to 30%, and provided electricity from the extracted brine. Unfortunately, ARM decreased the CO_2 mass fraction produced once breakthrough occurred.

1 INTRODUCTION

The Intergovernmental Panel on Climate Change (IPCC) has identified the rise in concentration of CO_2 in the atmosphere, resulting from the emission of CO_2 from power generation and industrial sources, as a contributing source of the rise in the global mean temperature (IPCC, 2014). To have a 50% chance to limit the global mean temperature rise to 2°C, the IPCC has defined a limit of 450 ppm for the concertation of atmospheric CO_2, which limits the total amount of CO_2 that can result in the atmosphere after 2011 to 1000 Gt (IPCC, 2014). The majority of the world's nations agreed on this atmospheric limit of CO_2 in the Paris Agreement (United Nations Framework Convention on Climate Change, 2015). To maintain CO_2 concentrations below this limit, a reduction and eventual elimination of CO_2 emissions into the atmosphere is required. To date, no single technology or approach can provide the required reduction in CO_2 emissions, however, multiple measures, such as renewable energy sources and Carbon Capture and Storage (CCS), can be used to achieve these limits.

Carbon Capture and Storage (CCS) can be used to reduce the emission of CO_2 from existing power plants and industrial sources, capturing CO_2 at the source and storing the CO_2 in a subsurface reservoir, permanently trapping the CO_2 underground in depleted oil and gas reservoirs, existing saline aquifers, and as part of enhanced oil recovery (EOR). Large volumes of CO_2 can be stored in these subsurface reservoirs, particularly in sedimentary basins which are naturally permeable and extend across large portions of North America (Randolph and Saar, 2011a). However, the pore space for these reservoirs is occupied by water which has a low compressibility. The subsequent injection of CO_2 will result in a CO_2-plume, which increases in volume over time. If the storage reservoir is a closed formation, brine displacement is restricted, and the volume of CO_2 that can be injected is limited, thereby increasing the reservoir pressure and reducing the CO_2 storage potential. Additionally, the resulting pressure buildup can result in CO_2 leakage and could cause fractures. To provide sufficient storage to mitigate climate change, reservoir pressures must be managed to allow for the storage of large volumes of CO_2.

Active reservoir management techniques have been proposed to limit the reservoir overpressure during CO_2 injection for Carbon Capture and Geologic Storage. Proposed methods involve producing brine pre-injection at the injection well (Buscheck et al., 2014), and concurrently producing brine at a production well (Bergmo et al., 2011; Buscheck et al., 2012; Dempsey et al., 2014). These methods involve drilling additional wells to produce fluid, which may have limited lifespans and may become obsolete once the CO_2 plume has reached the well. However, these wells may be utilized for CO_2-Plume Geothermal (CPG) Systems which use the CO_2 as the working fluid for a geothermal energy system, capable of producing power from low temperature resources.

CO_2 was proposed as a geothermal working fluid by Brown (Brown W., 2000) as CO_2 has several advantages over brine as a geothermal heat extraction fluid. The main advantages of using CO_2 in place of brine are that CO_2 has lower mineral solubility, larger density variation with temperature, and lower viscosity than brine (Randolph and Saar, 2011a, 2011b, 2011c, 2010). These advantages allow CO_2 to reduce mineral scaling in the pipes, operate as a thermosiphon which reduces or possibly eliminates the need for circulation pumps, and reduces the pressure loss in the reservoir compared to brine (Adams et al., 2015, 2014, Atrens et al., 2010, 2009; Brown W., 2000; Pruess, 2008, 2006).

Once implemented, CPG systems would operate using naturally permeable subsurface reservoirs, such as saline aquifers, although partially depleted oil and gas reservoirs may also be used, in sedimentary basins. Deep, saline aquifers are a common target for CCS projects and have mostly been investigated for power generation employing CPG (Adams et al., 2015, 2014, Garapati et al., 2015, 2014b, Randolph and Saar, 2011a, 2011c, 2011b, 2010). CPG is a different concept than a CO_2-Enhanced Geothermal System (EGS) (Atrens et al., 2010, 2009; Brown W., 2000; Pruess, 2008), which, by definition, use geologic formations whose permeability had to be artificially increased by hydraulic stimulation. Such EGS, also known as hot dry rock (HDR), conveying their original lack in permeable fluid pathways, are small in scale, providing a limited storage volume for captured CO_2. Previous studies have demonstrated that CO_2 is a better heat extraction fluid than brine for low to moderate temperatures and permeabilities (Adams et al., 2015), is more dispatchable then wind and solar (Adams and Kuehn, 2012), can operate using a thermosiphon (Adams et al., 2014; Atrens et al., 2010, 2009), and can operate as a large-scale, highly efficient energy storage system (Fleming et al., 2018). Other CO_2-based geothermal systems include the CO_2-Bulk Energy Storage (CO_2-BES) system (Buscheck et al., 2016) that uses multiple horizontal circular injection and production wells to produce power by circulating both CO_2 and brine. In this process the CO_2 is used as a cushion gas, increasing the reservoir pressure allowing brine to be produced without the need for down-well circulation pumps which are typically required for brine production.

While the effectiveness of the CPG system as a power and energy storage system has been demonstrated (Adams et al., 2015, 2014; Fleming et al., 2018; Garapati et al., 2015; Randolph and Saar, 2011b), research has not focused on different CO_2 reservoir priming methods before the CPG power generation begins. In this paper, we demonstrate how a CPG system can benefit by using active reservoir management during the initial reservoir priming period. Specifically, we demonstrate how active reservoir management can generate power, reduce the overpressure of the reservoir at the injection well, and reduce the time required for CO_2 to break through at the production well of a CPG system.

2 METHOD

We simulate CO_2-plume development in a saline reservoir by combining a reservoir model with a surface power generation system model, employing two software packages. The subsurface reservoir is simulated using TOUGH2 (Pruess et al., 1999) with the ECO2N equation of state module (Pruess, 2005). The surface power plant, injection pump, and vertical wells are simulated using Engineering Equation Solver (EES) (Klein and Alvarado, 2002) with the built-in thermodynamic properties of CO_2 (Span and Wagner, 1996) and water (Haar et al., 1984).

2.1 Reservoir Model

The CPG system operates using a saline aquifer with a developed CO_2 plume to produce heat from the subsurface. We simulate the reservoir as an axisymmetric cylindrical reservoir, similar to previous mixed fluid CPG reservoir simulations (Garapati et al., 2015). For the purposes of this paper we use a 2.5 km deep reservoir, with a temperature of 102.5°C and pressure of 25 MPa (assumed geothermal temperature gradient 35°C/km, ambient mean surface temperature of 15°C, and a hydrostatic pressure gradient of 10 kPa/km). The reservoir is initially filled with 20 wt% NaCl brine and is bounded by a low-permeability caprock above and bedrock below. The reservoir is simulated out to 100 km to avoid model boundary effects. The heat transfer through the top and bottom boundaries are modeled using semi-analytic heat transfer (Pruess et al., 1999).

The reservoir uses a center vertical injection well, and a horizontal circular production well located at a radius of 707 meters just below the caprock, similar to previous CPG models. The production well radius of 707 meters was selected to correspond to previous inverted five spot CPG reservoir models (Adams et al., 2015, 2014, Randolph and Saar, 2011c, 2011b, 2011a, 2010) and existing cylindrical models (Garapati et al., 2015, 2014b). When fluid was produced from the production well, the downhole pressure was fixed at the hydrostatic pressure. Additionally, the production well productivity index is set using the relationship from Coats (1977), as described in TOUGH2 (Pruess et al., 1999).

We simulate the injection process using five different CO_2 injection mass flow rates (50 kg/s, 100 kg/s, 150 kg/s, 200 kg/s, and 250 kg/s) and two different reservoir permeabilities (1×10^{-13} m^2 and 5×10^{-14} m^2). Each case is simulated for 2.5 years, which is a sufficient timeframe to ensure CO_2 breakthrough at the production well in all cases.

2.2 Surface Model

The surface power plant model provides the amount of electric power that can be produced from the hot brine and the amount of power consumed to pump the CO_2 into the reservoir. The surface model consists of a pump, throttling valve, and a vertical well for CO_2 injection, and a vertical well and a Rankine power system for the produced brine. The surface power plant is connected to the reservoir by five vertical wells: four production wells and a single injection well, consistent with previous CPG power systems (Adams et al., 2015, 2014). CO_2 is injected in the vertical injection well and brine is produced in the four vertical production wells. The production wells are connected at equal spacing to the horizontal-circular production well in the reservoir. The surface model is coupled with the reservoir model at the injection and production well downhole points.

The defined system is illustrated in Figure 1. CO_2 is transported to the site in a surface pipeline. For pipeline transport, CO_2 is compressed to pressures above the critical pressure (P_{crit} = 7.4 MPa), typically to pressures greater than 8 MPa to avoid multi-phase flow

(IPCC, 2005). We therefore assume that CO_2 at the surface at the injection site (State 1) is 8 MPa and we vary the CO_2 surface temperature between 15°C and 30°C to vary the density of the injected CO_2. The density of the CO_2 impacts the gravitational compression, and thus the downhole pressure, discussed below.

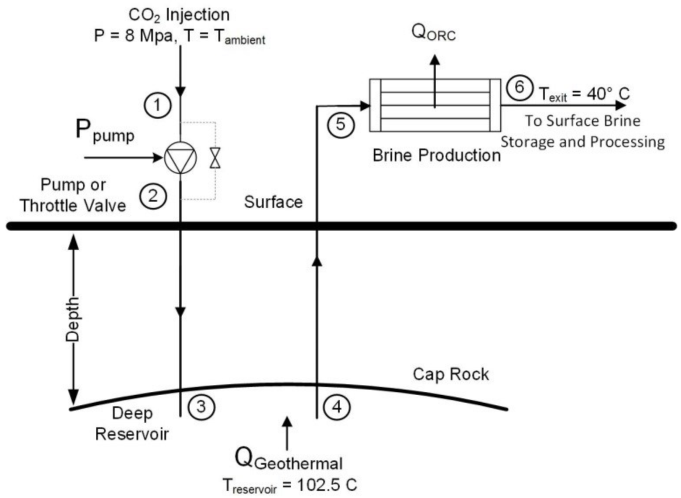

Figure 1: System diagram for CO_2 injection and brine production from a saline aquifer for CO_2 storage prior to the operation of the CO_2-Plume Geothermal (CPG) system. The surface power system for the CPG system is not shown, but is defined in Adams et al. (2015).

At the storage site, the CO_2 is compressed further and injected into the subsurface reservoir. The CO_2 undergoes two compression processes at the site; the CO_2 is first compressed by a pump at the land surface, and then, in the vertical injection well, through a gravitational compression process. The surface pumping consumes power, $\dot{W}_{pump}$, which is determined by the CO_2 mass flow rate and the enthalpy difference across the pump,

$$\dot{W}_{pump} = \dot{m}_{CO2}(h_2 - h_1). \tag{1}$$

We assume the pump has a 90% isentropic efficiency. In some cases, depending on the reservoir pressure at the injection site, pumping is not required and is replaced by a throttling value. The throttling process is modeled as an isenthalpic process from state 1-2.

After the pump, the CO_2 is injected into the subsurface reservoir (state 3) through a vertical injection well. The well provides an adiabatic compression process due to gravitational compression as the CO_2 descends down the well. The bottom hole injection well pressure is determined by the TOUGH2 reservoir model. Thus, the pumping requirement is determined by the fixed states 1 and 3.

We simulate the vertical well using a model from previous work (Adams et al., 2015, 2014), which numerically integrates the well over 100 meter elements. The model solves the continuity, energy, and momentum equations across each element. The well is assumed to be adiabatic, and changes in kinetic energy are neglected. Frictional pipe losses are modeled using the Darcy-Weisbach relation for a 0.41 m diameter well with a surface roughness of 55 µm (Farshad and Rieke, 2006). We use thermodynamic properties of pure CO_2 and water in the injection and production wells, respectively.

Brine is produced from the reservoir at the circular, down hole production well (State 4). The reservoir pressure here and the mass flow rate are determined by the TOUGH2 model. The brine is then delivered to the surface (State 5) through the vertical production well without a circulation pump, due to the overpressure in the reservoir at the production point. At the surface, heat is extracted from the brine as it is cooled to 40°C. The heat is used to produce power using a secondary Rankine cycle power plant. We model the power plant using a Rankine cycle efficiency (η_{ORC}) and the Carnot efficiency (η_{cc}) (Adams et al., 2014). The power produced from the power plant is the product of the heat extracted from the brine, the Rankine cycle efficiency, and the Carnot efficiency, given as

$$\dot{W}_{ORC} = \eta_{ORC}\eta_{cc}\dot{Q}_{ORC}. \tag{2}$$

The Rankine cycle efficiency, η_{ORC}, is set at 33% and is determined from existing geothermal plants (DiPippo, 2016). The Carnot cycle efficiency is defined as,

$$\eta_{CC} = \frac{T_{reservoir} - T_{ambient}}{T_{reservoir}}. \tag{3}$$

The heat extracted from the brine is the product of the brine mass flow rate and the enthalpy difference, given as,

$$\dot{Q}_{ORC} = \dot{m}_{brine}(h_5 - h_6). \tag{4}$$

The cooled brine is not re-injected into the reservoir and is assumed to be disposed of by a third party.

We define the net power as the difference between the electrical power generated from the production of hot brine and the power consumed to compress and inject the CO_2,

$$\dot{W}_{net} = \dot{W}_{ORC} - \dot{W}_{pump}. \tag{5}$$

We integrate the net power generation from the beginning of the injection period until CO_2 breakthrough, t_{bt}, occurs to determine the total net energy provided by the system,

$$W_{net} = \int_0^{t_{bt}} \dot{W}_{net}\, dt. \tag{6}$$

3 RESULTS

We discuss the modeling results in terms of the brine extraction, energy generation, reservoir overpressure at the injection well, and the CO_2 breakthrough time by comparing the brine extraction cases with cases with only CO_2 injection.

3.1 CO_2 Injection and Fluid Production

Active Reservoir Management (ARM) during the CO_2 plume development period requires brine to be produced from the reservoir using the CPG production wells. The resulting brine and CO_2 production for the five mass flow rates and the two permeabilities are shown in Figure 2 for the 2.5-year injection process.

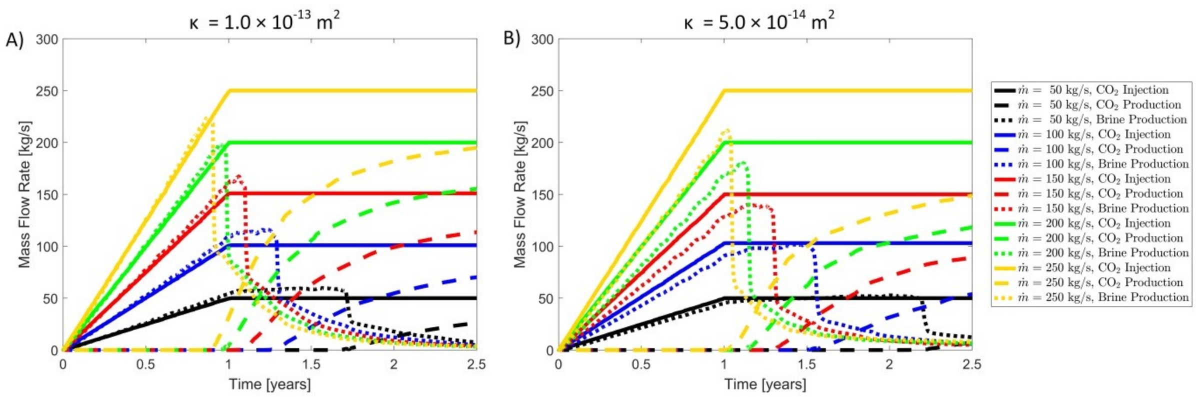

Figure 2: Mass flow rates for CO_2 injection and CO_2 and brine production during CO_2 plume development.

The brine extraction rate increases with the CO_2 injection mass flow rate and the reservoir permeability, as shown in Figure 2. The brine extraction rate was observed to exceed the CO_2 injection mass flow rate for all of the high permeability (1.0×10^{-13} m^2) cases, as well as in the 50 kg/s injection flow rate for the low permeability (5.0×10^{-14} m^2) case. These elevated brine extraction rates occur because CO_2 is less dense than brine ($\rho_{co2} \sim 575$ kg/m^3 to 835 kg/m^3 while $\rho_{brine} \sim 935$ kg/m^3 at the reservoir conditions) and therefore will displace a larger amount of brine.

Initially, the fluid produced from the reservoir is composed entirely of brine, but over time the produced fluid transitions from brine to mostly CO_2 with some entrained brine, as shown in Figure 2. The breakthrough of CO_2 at the production well corresponds to a sharp decline in the production of brine (i.e. 50-75% reduction in flow rate). At the end of the 2.5-year simulation, all cases, except the 50 kg/s CO_2 injection case, have over 90% CO_2 in the produced fluid, which is important for the operation of the turbomachinery in the preferred, so-called direct CPG cycle, where produced fluid is passed, possible after water is removed, directly into the CO_2 turbine, is not exchanging its heat to a secondary power loop.

The CO_2 breakthrough is illustrated in Figure 3. When brine is produced, the breakthrough time is decreased. However, the mass fraction of CO_2 at the production well after breakthrough is lower when brine is produced than when brine is not produced. This occurs for two reasons. First, the production of fluid includes some CO_2 and thus less CO_2 is permanently injected to displace brine within the reservoir. Second, the production of brine before breakthrough changes the pressure field, and therefore the plume shape, such that CO_2 is not uniform around the production well.

The CPG system requires the produced CO_2 mass fraction to be greater than 94% for the operation of the turbomachinery (Garapati et al., 2015, 2014a), although resent discussions with turbomachinery manufacturers suggest that larger mass fractions of water should be acceptable, due to the low density difference between supercritical CO_2 and liquid water (i.e. a factor of ~ 2 compared to a factor of ~1000 for liquid and vapor states of water). To obtain 94% mass fraction in the production well, the CO_2 mass fraction in the reservoir elements surrounding the well must be greater than 28%. For instance in Figure 3A, the 250 kg/s case reaches 28% mass fraction in 1.02 years for the CO_2 injection only case, but requires 1.57 years when brine is produced. Thus, while ARM can reduce the breakthrough time, it may also delay the operational start of the CPG system. However, while it may take longer to reach the suggested 94% CO_2

produced mass fraction, limited CPG operation could begin by separating the CO_2 and brine at the surface, enabling some power generation which could offset any delay.

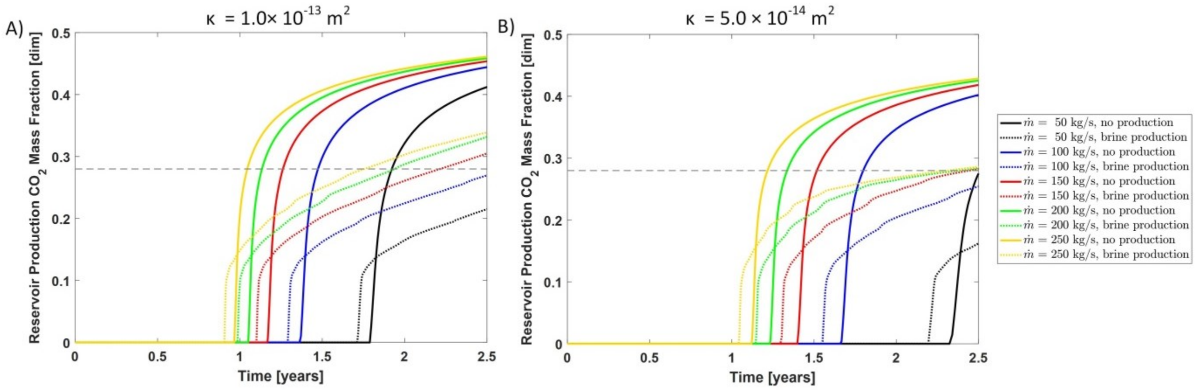

Figure 3: CO_2 concentration at the production well in the reservoir with and without brine production. The first non-zero fraction denotes the time at which CO_2 breakthrough occurs for two different reservoir permeabilities of 1.0×10^{-14} m^2 (A) and 5.0×10^{-14} m^2 (B).

The key results are shown in Table 1. Active Reservoir Management (ARM) resulted in a 20% to 30% reduction in reservoir over pressure, a 4% to 7% reduction in breakthrough time, and less CO_2 injected before breakthrough, discussed in detail below.

Table 1: Summary of the key performance characteristics of the system.

Permeability	Mass Flow Rate	Injection Over Pressure[1,2]	Reduction in Over Pressure (ARM)	Break Through Time [2]	Reduction in Break Through Time	CO_2 Injected (Inject Only)	CO_2 Injected (ARM)	Brine Produced (ARM)
(m^2)	(kg/s)	(MPa)	(%)	(y)	(%)	(Mt)	(Mt)	(Mt)
1.00E-13	50	2.08	25.48	1.72	4.33	2.04	1.91	2.04
	100	3.64	28.02	1.34	5.64	2.74	2.49	2.57
	150	5.11	29.16	1.15	5.79	3.16	2.84	2.88
	200	6.5	30.62	1.03	6.07	3.47	3.08	3.06
	250	7.49	31.51	0.96	6.54	3.68	3.23	3.17
5.00E-14	50	3.83	19.84	2.29	6.27	2.90	2.70	2.5
	100	6.89	21.34	1.67	6.99	3.68	3.32	2.99
	150	9.83	22.08	1.39	7.64	4.29	3.80	3.21
	200	12.55	21.75	1.22	7.3	4.64	4.09	3.32
	250	15.17	21.96	1.11	6.86	4.92	4.31	3.42

[1] Overpressure is the pressure difference between the injection pressure and the hydrostatic reservoir pressure
[2] Defined for the CO_2 injection only case

3.2 Breakthrough Time

The CPG system operates by circulating CO_2 within the reservoir to produce power, thus, the CO_2 plume must reach the production well before the system operation can commence. Therefore, we consider the benefit of using Active Reservoir Management (ARM) to decrease the time that is required to develop the reservoir and allow CPG operations to commence earlier. For consistency between the ARM and injection only cases, we use the CO_2 breakthrough time, which we define as the moment in time, when there is a gas saturation of >1% CO_2 at the production well.

The production of brine during the injection of CO_2 for the CO_2 plume development decreases the time required for breakthrough of CO_2 at the production well. The production of brine decreased the CO_2 breakthrough time for all cases, as ARM reduces the pressure at the production well and creates a preferential pressure gradient, and thus a preferential CO_2 flow path from the injection well to the production well. The average reduction in breakthrough time is 26 days (-5.6%) and 37 days (-7.0%) for the 1.0×10^{-13} m^2 and 5.0×10^{-14} m^2 permeability cases, respectively.

The breakthrough time with brine production decreases as the CO_2 injection mass flow rate increases. For example, the reduction in the breakthrough time is 47 days for the 50 kg/s CO_2 injection mass flow rate and is 29 days for 250 kg/s CO_2 injection mass flow rate, for a permeability of 5.0×10^{-14} m^2. However, the reduction in breakthrough time is fairly constant, percentage-wise, for both investigated permeability cases. This is visibly apparent in Figure 4. Thus, we can conclude that for most flow rates, we expect brine production to decrease the CO_2 breakthrough time by 4% to 7%.

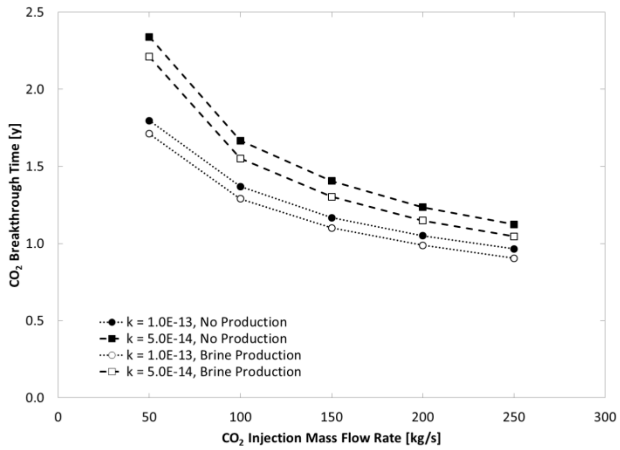

Figure 4: The CO_2 breakthrough time as a function of the mass flow rate.

3.3 Reservoir Pressures and Energy Generation

The use of Active Reservoir Management (ARM) during the plume development period for a CPG system for energy generation has two main benefits: 1) by producing brine, the injection pressure is reduced and thus the additional power required to inject CO_2 into the reservoir is reduced, and 2) power can be generated using the hot, produced brine. In all simulations, brine was produced without the need for a downhole circulation pump, and therefore the only pumping required is for the injection of CO_2 into the reservoir.

The amount of CO_2 pumping power required is shown in Figure 5. When Active Reservoir Management is used, the pumping power is reduced, due to the lower downhole injection pressure. For example, in Figure 5C, the CO_2 pumping power (shown as a negative quantity for power required) for the 250 kg/s case at one year is 2.85 MWe. However, in Figure 5A, the CO_2 pumping power using active reservoir management is 1.97 MWe, for a reduction of 31%.

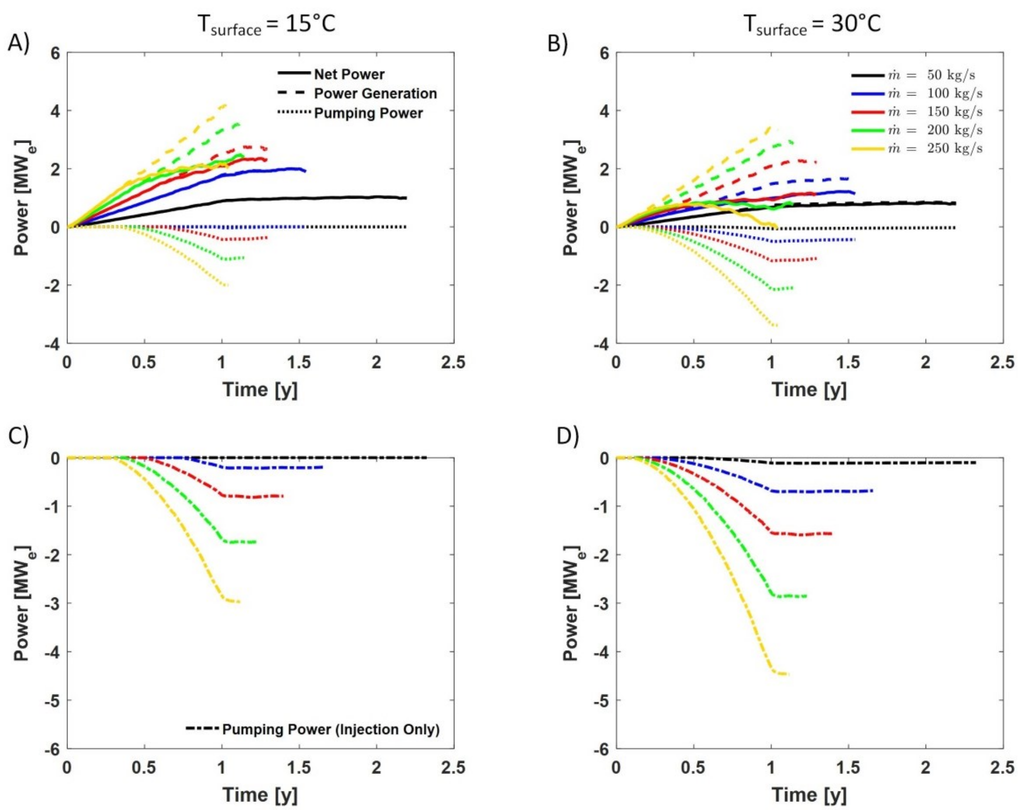

Figure 5: Power generation/consumption prior to CO_2 breakthrough for the low-permeability cases ($\kappa = 5\times10^{-14}$ m^2) using ARM (A,B) and the CO_2 injection only case (C,D) for CO_2 surface temperatures of 15°C (A,C) and 30°C (B,D).

Power is generated using the hot brine with Active Reservoir Management (ARM). At one year, Figure 5B shows the 150 kg/s (CO_2 injection) case generates approximately 2.09 MW_e of electricity. When the corresponding -1.15 MW_e of pumping power is deducted, the system still produces 0.93 MW_e net of electricity. This is contrasted with the -1.54 MW_e (Figure 5D) of pumping power required in the same case if brine is not produced to regulate the reservoir pressure. Thus, it is clear that one advantage of ARM is net power generation.

These advantages lead to similar conclusions by Buscheck et al. (2016) in the design of the CO_2-BES earth battery system. That is, ARM is necessary to reduce overpressures and can therefore be used to generate electricity. However, here, we consider how ARM also affects the CO_2 breakthrough time. This, in turn, affects the time it takes to deploy a CPG system.

Producing brine with Active Reservoir Management (ARM) reduces the overpressure at the production well, shown in Figure 6A. This, in turn, reduces the entire formation pressure, including the downhole injection well pressure, shown in Figure 6B. For instance, after a duration of one year, using ARM in the 250 kg/s (CO_2 injection) case, the production well pressure is reduced from 29.2 MPa to 25.1 MPa, and correspondingly the injection well pressure decreases from 38.9 MPa to 35.8 MPa.

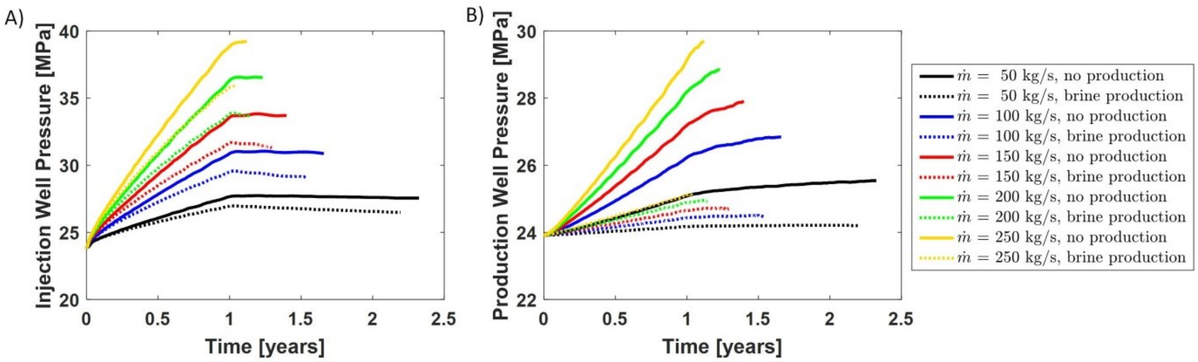

Figure 6: The pressure at A) the injection well, and B) the production well for the ARM and injection only simulations for the low permeability cases (κ = 5.0×10^{-14} m²).

The power that the hot brine generates is greater than the power consumed by the CO_2 injection pumps, and thus, the net energy is positive, as shown in Table 2. The net energy does not always increase as the mass flow rate increases. The net energy is the sum of the brine energy generated (positive) and the pumping energy consumed (negative). As the CO_2 injection rate increases, the power production tends to increase linearly; however, the pumping load increases at a higher rate. Thus, there is a complex relationship between CO_2 injection rate and net energy. Thus, the energy-maximizing CO_2 injection rate would have to be determined for a specific situation.

Table 2: Summary of the electric energy generation prior to CO_2 breakthrough.

		CO_2 Temperature = 15°C		CO_2 Temperature = 30°C	
Permeability	Mass Flow Rate	Net Energy Generation (Inject Only)	Net Energy Generation (ARM)	Net Energy Generation (Inject Only)	Net Energy Generation (ARM)
(m²)	(kg/s)	(GWe-h)	(GWe-h)	(GWe-h)	(GWe-h)
1.00E-13	50	0	11.1	0	9.18
	100	0	13.9	-1.47	11.3
	150	0	15.6	-2.13	12.99
	200	-0.6	16.5	-4.72	12.09
	250	-1.5	17.2	-6.3	11.98
5.00E-14	50	0	13.6	-1.56	10.62
	100	-1.6	16.2	-6.72	10.2
	150	-4.6	15.8	-10.45	8.45
	200	-7.3	14.6	-13.85	6.45
	250	-13.72	13.4	-22.75	4.6

The net electric energy generated prior to breakthrough of CO_2 at the production well is shown in Figure 7. This is contrasted to the injection-only case, which consumes energy. The lower ambient air temperature at the surface generates more energy than the higher temperature ambient air case, due to both decreased pumping loads and increased brine energy generation. In both cases, the low permeability reservoir resulted in more energy at the lower injection flow rates than the high permeability reservoir, which is a result of the delayed breakthrough of the CO_2, allowing electric power to be generated with the brine for a longer time. However, at larger mass flow rates, the high permeability reservoir generates more energy as the injection pressure is lower, which decreases the energy consumed by the pumps.

In all cases, producing brine during CO_2 priming (Active Reservoir Management - ARM) reduces the pumping power requirements and reduces the time required to achieve CO_2 breakthrough. Additionally, power may be generated during this phase to produce net-positive energy to the electric grid. However, these come at the expense of decreased CO_2 mass fraction in the produced fluid once breakthrough occurs. Thus, different reservoir management choices may be made during the priming phase, depending on the CO_2 composition requirements after priming.

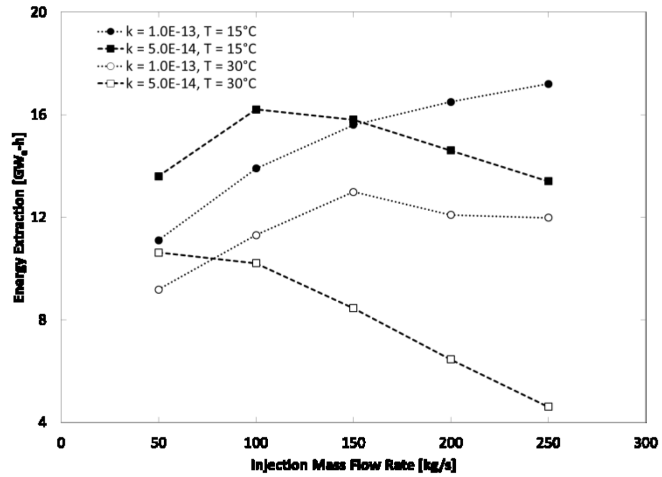

Figure 7: Net electric energy generated by extracting brine from the CPG reservoir prior to the breakthrough of CO_2 at the production well.

4 CONCLUSIONS

We investigate how active reservoir management can be applied to the development of the CO_2 plume prior to the operation of a CO_2-Plume Geothermal (CPG) system. We simulate the development of the CO_2 plume both without brine production (CO_2 injection only) and with brine production (Active Reservoir Management - ARM). Our results, obtained for two ambient air heat rejection temperatures, two reservoir permeabilities, and five CO_2 injection mass flow rates, allow us to draw the following conclusions:

The CO_2 breakthrough time can be reduced by producing brine during the CO_2 plume development. On average the reduction is approximately 32 days, i.e., a reduction by 4% to 7%. This reduces the time required to bring a CPG plant online.

Producing brine during the CO_2 plume development causes reduced CO_2 mass fractions in the production well, once breakthrough occurs. Producing brine causes preferential CO_2 flow paths, resulting in less displaced brine and a different plume shape during the priming phase. This resulted in both: less CO_2 required to prime the reservoir and greater brine production immediately after CO_2 breakthrough.

The CO_2 reservoir overpressure is reduced when producing brine and reduces the injection pumping power required. On average, brine production tends to decrease the reservoir overpressure by 20% to 30%. For the 5×10^{-14} m^2 permeability case at 150 kg/s (CO_2 injection) and a 30°C mean ambient air temperature; this reduction in reservoir pressure decreases the CO_2 pumping power from 1.54 MW_e to 1.15 MW_e.

Electricity can be generated using the heat extracted from the produced hot brine prior to CO_2 breakthrough. In all the cases simulated, the power generated from the produced brine was larger than the power consumed to inject the CO_2 from the pipeline pressures, resulting in net power, and thus energy, generation during the CO_2 plume development prior to the operation of the CPG power system.

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