

REMOVAL OF WATER FOR CARBON DIOXIDE-BASED EGS OPERATION

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ABSTRACT

CO₂-based Engineered Geothermal Systems (EGS) have been explored from the perspectives of thermodynamic performance, in-reservoir chemical reactivity, and economic viability. Previous works have correctly noted the important role that initial water content in the geothermal reservoir will play in determining the viability of the concept, but have not examined reservoir water content from a quantitative basis. Here we assess the effect of water concentration limits for carbon dioxide-based EGS operation. We examine the relationship between drying time and reservoir characteristics such as connectivity, fluid volume, and fluid losses. This is expanded by calculation of total amount of carbon dioxide sequestered, and total amount of water produced.

INTRODUCTION

Carbon-dioxide-based EGS is the concept of utilizing carbon dioxide as an alternative to water as the heat extraction fluid in Engineered Geothermal Systems (EGS). Like water, this may incorporate a second, 'binary' power generation system, but typically is considered to consist of a single-loop of the subsurface system and power generation equipment, similar to traditional steam geothermal power plants.

Carbon-dioxide-based EGS systems have been examined in a number of works over the past years; these have focused primarily on modeling of the system with an emphasis on performance or on the fluid and rock chemistry (Brown 2000; Pruess 2006; Pruess and Azaroual 2006; Pruess 2008; Atrens, Gurgenci et al. 2009; Atrens, Gurgenci et al. 2009; Gurgenci 2009; Atrens, Gurgenci et al. 2010; Atrens, Gurgenci et al. 2010; Pritchett 2010). These are important considerations for viability of carbon-dioxide-based EGS, however a number of other questions relating to viability remain, particularly:

- Viability and time-scales of 'drying-out' of the reservoir
- Solubility of trace contaminants present in the reservoir in CO₂ or CO₂-rich fluids compared to H₂O
- Quantity of CO₂-sequestration likely to occur

Here we focus on the 'drying-out' of the reservoir, which occurs as a result of replacement of any water initially present in the system with carbon-dioxide.

This is an important issue, as water and carbon dioxide are not mutually miscible at all concentrations. If sufficient water is present in the carbon dioxide, a water-rich phase will condense in surface equipment. That phase will be saturated with carbon dioxide and, as a result, also with carbonic acid, potentially affecting the choice of materials of construction. If condensation occurs in turbomachinery, problems with erosion of the turbine blades are also likely to occur.

Previous work (Atrens, Gurgenci et al. 2011) indicates that the water content allowable in a CO₂-rich phase before condensation will occur in the turbine is in the range of 1-6 mol%. Some condensation is likely to always occur in surface cooling equipment.

The purpose of this work is to examine the time required to dry an EGS reservoir to an extent that would allow passing produced fluid through a turbine on the surface.

METHODOLOGY

To assess the time required to sufficiently dry an EGS reservoir, we use a simple conceptual model of a constant volume system with defined constant volumetric input and output flows. We examine the change in CO₂ proportion in such a system. The

model used is simple to allow for an analytical solution, and to allow for straightforward examination of the relevant parameters.

The model consists of a constant volume of free space (V_R) within the ‘operational’ volume of the reservoir. We use the term ‘operational’ to keep this region distinct from other regions of the geological system to which it may be connected, but which only play a peripheral role in system performance. Into this reservoir, a constant volume of carbon dioxide is injected (V_{CI}), and a constant volume of reservoir fluid flows out of it into the production well (V_P), and into the surrounding reservoir system as fluid loss (V_L). Additionally a fixed volume of reservoir fluid is removed by a mixing mechanism (V_M), which is replaced by an equal quantity of pure water. A conceptual diagram of this system is shown in Figure 1.

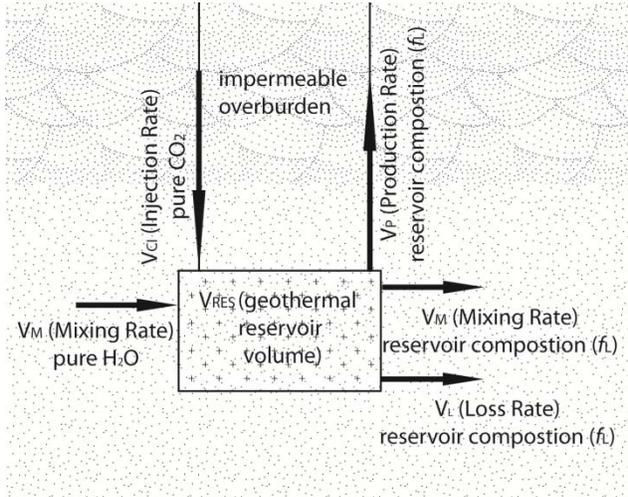


Figure 1: Conceptual diagram of system

Model calculations

To analyse the described system, we use the set of equations as defined below:

$$\dot{V}_{CI} = \dot{m}_{CO_2} / \rho_{CO_2} \quad [1]$$

$$\dot{V}_L = \dot{V}_{CI} f_L \quad [2]$$

$$\dot{V}_P = \dot{V}_{CI} (1 - f_L) \quad [3]$$

$$f_{CO_2} = V_{CO_2} / V_R \quad [4]$$

$$\frac{dV_{CO_2}}{dt} = \dot{V}_{CI} - f_{CO_2} (\dot{V}_P + \dot{V}_M + \dot{V}_L) \quad [5]$$

where at $t=0$, $V_{CO_2}=0$, f_L is the loss factor for the system, f_{CO_2} is the volume fraction of CO_2 in the reservoir, ρ_{CO_2} is the density of carbon dioxide at the

reservoir temperature and pressure, and V_{CO_2} is the volume of carbon dioxide in the reservoir operational volume. For completeness, while it is not independent, the volume of water in the reservoir can be defined by the equation:

$$\frac{dV_{H_2O}}{dt} = \dot{V}_M - (1 - f_{CO_2})(\dot{V}_P + \dot{V}_M + \dot{V}_L) \quad [6]$$

where at $t = 0$, $V_{H_2O} = V_R$.

This set of equations can be solved by integration to provide a function for the volume fraction of carbon dioxide in the reservoir at any given time t . The resulting equation is as follows:

$$f_{CO_2} = \frac{\dot{V}_{CI}}{\dot{V}_M + \dot{V}_{CI}} \left(1 - e^{-\frac{\dot{V}_{CI}}{\dot{V}_M} t} \right) \quad [7]$$

In this equation, the equilibrium concentration is represented by the first coefficient, and the drying-time half life is defined by the coefficient of t in the exponential term. This can also be rearranged to provide drying time t as a function of required volumetric fraction of CO_2 :

$$t = -\frac{V_R}{\dot{V}_{CI}} \ln \left[1 - f_{CO_2} \frac{\dot{V}_M + \dot{V}_{CI}}{\dot{V}_{CI}} \right] \quad [8]$$

Conversion from volume fraction f_{CO_2} to mole fraction x_{CO_2} is possible from the function:

$$f_{CO_2} = \frac{x_{CO_2} \frac{M_{H_2O}}{\rho_{H_2O}}}{(1-x_{CO_2}) \frac{M_{CO_2}}{\rho_{CO_2}} + x_{CO_2} \frac{M_{H_2O}}{\rho_{H_2O}}} \quad [9]$$

where M represents molar mass of CO_2 or H_2O , and ρ represents density of CO_2 or H_2O . This allows direct conversion of the 1-6 mol% requirement mentioned previously into a volume fraction requirement at any specified temperature and pressure.

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We also note that additional quantities can be determined via integration over time of the volume fraction of CO_2 . Total net volume of CO_2 (V_{INET,CO_2}) injected after a given time t can be determined from:

$$V_{INET,CO_2} = \int_0^t \dot{V}_{CI} - \dot{V}_P f_{CO_2} dt \quad [10]$$

$$= \dot{V}_{CI} t - \dot{V}_P \frac{\dot{V}_{CI}}{\dot{V}_M + \dot{V}_{CI}} \left(t + \frac{\dot{V}_R}{\dot{V}_{CI}} e^{-\frac{\dot{V}_{CI}}{\dot{V}_M} t} - \frac{\dot{V}_R}{\dot{V}_{CI}} \right) \quad [11]$$

The total net volume of H_2O produced at the surface after a given time t that would require some form of disposal can be determined from:

$$V_{PNET,H2O} = \int_0^t (1 - f_{CO2}) \dot{V}_P dt \quad [12]$$

$$= \dot{V}_P \left[t - \frac{V_{Cl}}{V_M + V_{Cl}} \left(t + \frac{V_R}{V_{Cl}} e^{-\frac{V_{Cl}}{V_R} t} - \frac{V_R}{V_{Cl}} \right) \right] \quad [13]$$

For both of these total volumes, substitution of the overall system lifetime t_{max} provides the lifetime amount of CO₂ disposed of underground, and the amount of H₂O removed at the surface.

Parameter values for these sets of equations for the reference case are given in Table 1.

Table 1: Reference parameters.

Parameter	Value
Reservoir volume (V_R)	$0.01 * 10^9 \text{ m}^3$
Injection rate (V_{Cl})	$15070 \text{ m}^3 \cdot \text{day}^{-1}$
Loss fraction (f_L)	0.1
Mixing rate (V_M)	$1507 \text{ m}^3 \cdot \text{day}^{-1}$
Reservoir lifetime (t_{max})	25 years
Reservoir pressure (P_R)	49.05 MPa
Reservoir temperature (T_R)	200 °C
Mass injection rate (m_{CO2})	$100 \text{ kg} \cdot \text{s}^{-1}$

Note that the reference parameters given use a total volume of reservoir rock of 0.5 km^3 with a average porosity of 0.02, and an injection rate corresponding to expected flows in a reservoir of impedance equivalent to Soultz-sous-Forêt (Murphy, Brown et al. 1999; Atrens, Gurgenci et al. 2010).

RESULTS

First, we examine the basic behavior of the system described, which is that of 1st order decay towards an equilibrium composition. The decay rate is defined by the half-life term V_{Cl} / V_R , which is in units of day^{-1} . The final equilibrium achieved after infinite time is determined by the inputs of fluid into the system, the only two being V_{Cl} and V_M . As injected CO₂ is considered to be pure, and fluid mixing is considered to replace reservoir fluid with pure water, the overall equilibrium volume fraction of CO₂ is therefore the proportion of injected fluid out of the total mass input (i.e. $V_{Cl} / (V_{Cl} + V_M)$). This behaviour can clearly be seen in Figure 2.

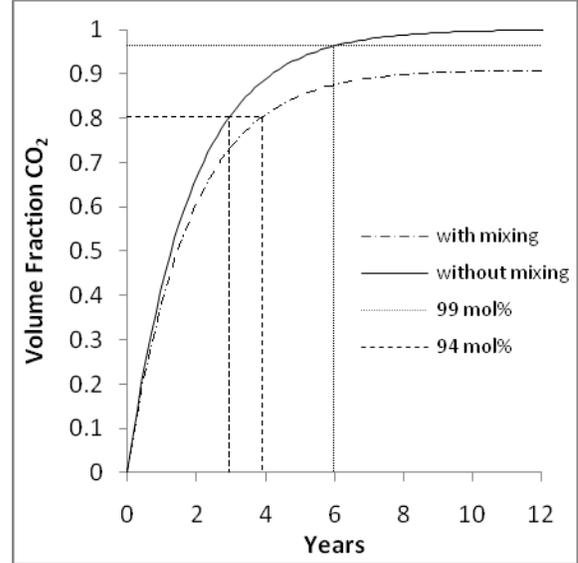


Figure 2: Volume fraction of carbon dioxide versus time, with drying time for different carbon dioxide concentrations noted

It is evident in Figure 2 that for achieving certain concentrations of CO₂ in the reservoir system may not be possible if influx of water from mixing is too high.

Change in system parameters

The effect of system parameters on the modeled system can be examined to determine how system behavior changes in response. We examine the effect of changing parameters on the time taken to sufficiently dry the geothermal reservoir for direct use of CO₂ in turbomachinery. As stated previously, the required minimum CO₂ concentration for produced fluid to be used in the turbine is 94 to 99 mol%. Using equation 9 for the reservoir pressure and temperature defined in Table 1, this is equivalent to ~ 80.4 to 96.3 vol%. We examine sequentially the role of the major system parameters V_{Cl} , V_R , and V_M .

CO₂ injection rate

The effect of CO₂ injection rate on the drying time for the system is shown in Figure 3.

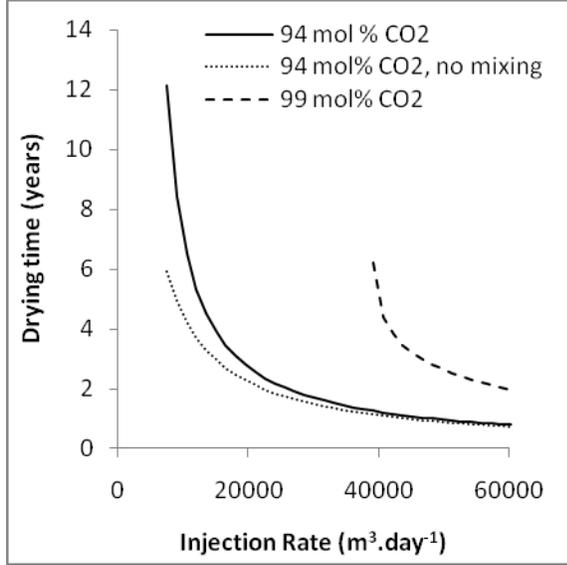


Figure 3: Drying time to specified mol %, versus injection rate

We note that there is strongly asymptotic behavior in response to this parameter; changing from low to moderate rates significantly speeds up the process, but the benefit of increased rate diminishes dramatically. For a reservoir of the temperature and pressure defined in Table 1, a volumetric rate of CO₂ injection of 20000 m³.day⁻¹ is equivalent to a CO₂ mass injection rate of 133 kg.s⁻¹. As evident from previous works (Atrens, Gurgenci et al. 2010), that rate could be achieved for a surface injection pressure of approximately 14 MPa absolute for a system of impedance equivalent to Soultz-sous-Forêt.

Reservoir volume

The role of ‘operational’ reservoir volume on drying time is shown in Figure 4.

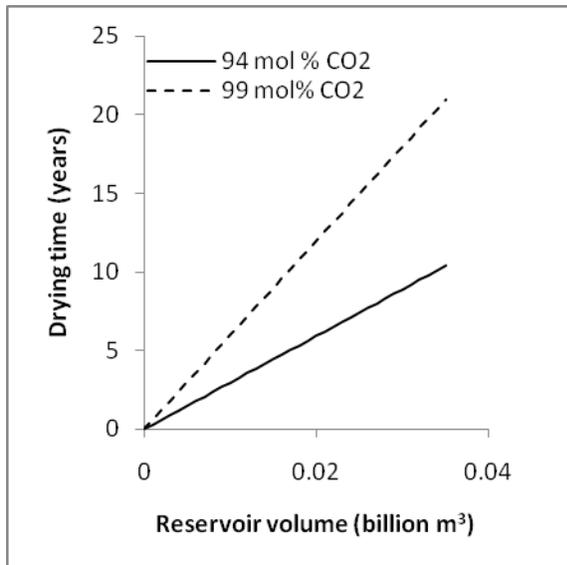


Figure 4: Drying time to specified mol %, versus reservoir volume

Figure 4 shows that drying time is directly proportional to reservoir volume. As mentioned previously, one billion cubic metres converts directly to one cubic kilometre, so for a reservoir porosity of 0.02, Figure 4 represents from 0 to 2 km³ gross reservoir volume.

Mixing rate

The effect of mixing rate is shown in Figure 5.

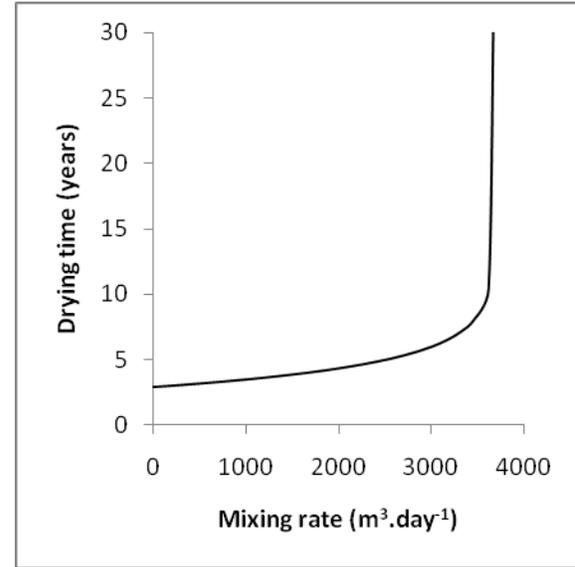


Figure 5: Drying time versus mixing rate, to reach 94 mol% CO₂

From Figure 5, it is evident that the rate at which pure water mixes with the reservoir volume has small effects for low mixing rates. As the mixing rate increases, the effect accelerates as it approaches the critical mixing rate, $V_{M,CRIT}$, such that:

$$\dot{V}_{M,CRIT} = \dot{V}_{CI} \frac{(1-f_{CO_2,CRIT})}{f_{CO_2,CRIT}} \quad [14]$$

where $f_{CO_2,CRIT}$ is the volume fraction of CO₂ corresponding to the mole fraction necessary to use produced fluid directly in turbomachinery. What this means is that for a targeted ‘dryness’ of the reservoir, mixing of water with the reservoir fluid will only be a moderate influence until a certain point, at which the mixing rate is sufficient to effectively make drying the reservoir impossible.

To put the magnitude of this effect in perspective, an increase from no mixing up to 80% of the critical mixing rate shown in Figure 5 results in doubling of drying time. Such a system would have an influx of

water comparable to 20% of the injected CO₂ flow-rate.

It should be noted that this behaviour is not a direct simulacrum of reality; sustained injection and mixing in the reservoir would be expected to lead over time to a reduction in purity in water surrounding the operational region. This would lead to a decline in the relative importance of mixing over time.

Total CO₂ sequestered

Using equation 11, we calculate the total amount of carbon dioxide sequestered underground over the lifetime of the reservoir. The results of this calculation are shown in Figure 6.

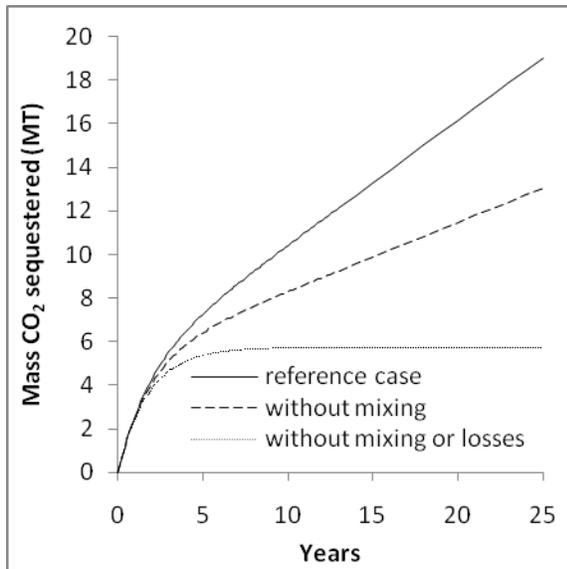


Figure 6: Total sequestration of CO₂ versus time, for reference case, for reference case without mixing, and for reference case with no mixing or losses

Note that even after the reservoir has reached a relatively consistent composition of carbon dioxide (as seen previously in Figure 2), there is substantial continuing consumption of carbon dioxide, due to the assumed loss rate of 10% of the injection flow. Similar results are seen for a system with no losses, but the mixing term still included (not shown). If both mixing and fluid loss are excluded from the model, the system reaches a final sequestration quantity proportional to the free volume of the reservoir multiplied by the density of the CO₂ at reservoir conditions.

Produced water at surface

Using equation 13, the amount of water produced at the surface can be calculated (note that as for CO₂

sequestered, this is the total cumulative amount over time).

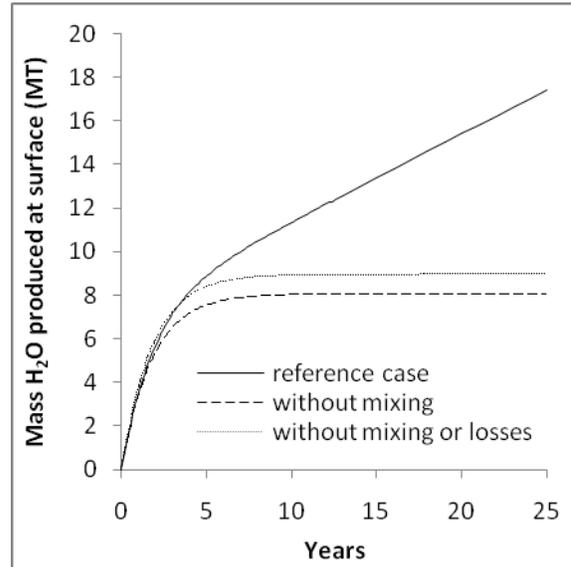


Figure 7: Total quantity of water produced at the surface, for reference case, for reference case without mixing, and for reference case with no mixing or losses

The behaviour of water produced differs slightly from that of carbon dioxide sequestered, because if no mixing occurs, the system will reach a point where no more water is produced from production well(s). Note that if the underground reservoir does not experience fluid losses, produced water will in fact *increase*. This happens because when losses are present, some of the water displaced by CO₂ flows out of the reservoir to elsewhere underground, whereas without losses all the reservoir water must exit the system to the surface (see Figure 1).

DISCUSSION

There are a number of simplifications included in this analysis that have been incorporated to allow an analytical solution. The effect of these simplifications is discussed below.

Single volume representation of reservoir

The operational region of the reservoir is represented as one single volume. That single volume is assumed to have constant composition, and equally all fluid in the reservoir outside that single volume is considered to be pure water. This approach is clearly a significant simplification compared to real reservoirs, making the results qualitative rather than quantitative. Inaccuracies also arise from the lack of accounting for appropriate time-scales for fluid flow, and neglecting concentration gradients across the system.

Concentration gradients within the reservoir system would likely result in more rapid drying times, as injected CO₂ would be more likely to directly displace water in the reservoir than to mix evenly with it. That is, in the early stages of drying-out of a reservoir, *only* water would be produced from the production well, as injected CO₂ replaces the water initially in the reservoir rather than mixing with it.

Not accounting for change in CO₂ concentration outside the ‘operational’ zone of the reservoir is also a conservative simplification. While such changes would consume some of the injected CO₂, that could be considered to originate from the ‘fluid loss’ term. On the other hand, a change in CO₂ concentration in reservoir fluids surrounding the operational zone would reduce the effect over time of the mixing rate in the model.

Operational volume versus total reservoir volume

We use a term in the model representing an ‘operational’ reservoir volume, which we consider to encompass the main areas of fluid flow between injection and production wells. This volume is not rigorously defined, and in fact, whether this is considered to be a larger or smaller region of the reservoir will significantly impact the fluid loss and fluid mixing terms in the model. The volume size used in this study (approximately half of a cubic kilometre of rock with a porosity of 0.02) is reasonable for the ‘operational’ volume of an EGS reservoir system, as while it is smaller than some stimulated EGS reservoir volumes, the full volume of an EGS system is unlikely to experience significant fluid flows.

Independence of loss rate

We utilised the loss fraction as an independent term (and it only affects the balance of carbon dioxide sequestered and water produced at the surface). In reality, the loss fraction encountered in a given reservoir will be a function of fundamental system properties, which will also affect the amount of mixing at the edges of the operational zone of the reservoir, and achievable fluid injection rates. In general, we expect that at a fundamental level, propensity for fluid injection, fluid losses, and fluid mixing will be proportional to the average native permeability (K) of the reservoir, that is:

$$\dot{V}_{CI}, \dot{V}_M, \dot{V}_L \propto K$$

However we also expect that fluid loss and fluid mixing are likely to depend on a pressure differential between the pressure within the reservoir (P_R), and that of pressurised fluid in the rock surrounding the operational area (P_{SURR}), that is:

$$\begin{aligned} \dot{V}_L &\propto P_R - P_{SURR} \\ \dot{V}_M &\propto P_{SURR} - P_R \end{aligned}$$

From this general framework, it would be expected that high fluid losses are likely to reduce time spent drying out an EGS system, as they are indicative of low influx of water from the surrounding rock.

Mutual miscibility of CO₂ and H₂O

The influence of mutual miscibility of CO₂ and H₂O was neglected in terms of calculating the volume balance. This will lead to inaccurate results when reasonable quantities of both CO₂ and H₂O are present in the system. This should not significantly affect calculated drying times, however, as when a single compound is the dominant component of the system, the volumetric deviation from ideal mixing is small. This is the case for the system as it approaches sufficient dryness for direct use of CO₂ in turbomachinery.

Reactivity of CO₂ with reservoir geology

We neglect reactivity of CO₂ with reservoir geology in this study. In reality, there may be significant interactions resulting in a range of possible outcomes, including dissolution of minerals leading to permeability increase, deposition of carbonates, leading to permeability decrease, or a combination of these types of reactions in different regions in the reservoir.

Reactions have been noted to have significant implications in terms of sequestration of CO₂, and flow behaviour within the reservoir. We note that there is significant potential for CO₂ reactivity to lead to change in injection, production, loss, and mixing terms of the model used over the lifetime of the reservoir.

Likely mixing rates for EGS

For this study we assume a relatively arbitrary volumetric rate of mixing between the fluid within the ‘operational’ region of the reservoir and the reservoir surroundings. It is difficult to predict what the actual rate is likely to be in a typical reservoir (and this is potentially an area where a more rigorous numerical model could be extremely useful). We note, however, that modelling of this will still be limited by a lack of data, and suggest that some understanding of mixing rates may be achieved from a combination of circulation and tracer test data (with appropriate transformation).

Long-term losses

We assume in this study that losses are constant within a given reservoir system. Real-world data from past EGS trials has not contradicted this, but relevant circulation tests have been limited to time-scales of months, instead of years as addressed here. It is expected that most reservoir systems would see a decline in fluid loss over time, as the destination sites for fluid outflow increase in pressure as they are filled. The time-scales over which that is likely to occur in EGS remains uncertain.

Field-scale production considerations

The various volumetric flow rates and static volumes considered in this work are representative of a doublet of wells. In reality, such a system is likely to consist of multiple sets of doublets or an integrated field, so as to achieve economies of scale with power conversion equipment. Drying times for an integrated field are likely to be lower than for an isolated doublet, as there is likely to be lower overall mixing with other fluids surrounding the geothermal reservoir, and there is the possibility of some shared overlap between relevant reservoir volumes.

CONCLUSIONS

There are a number of conclusions that can be made from this analysis:

- Drying-out is in general a first order function with a half life of injection rate divided by the operational volume of the reservoir;
- Drying-out times of a few years look likely for a 'typical' EGS reservoir before CO₂ can be used directly in power conversion equipment;
- Small mixing rates do not substantially alter the drying-out dynamic;
- Moderate mixing rates can make sufficient drying-out of the reservoir impossible (or may require additional infrastructure in the surface plant to dehydrate produced fluids);
- Fluid loss from the reservoir does not change drying-out dynamics unless it affects other system parameters;
- Systems with fluid losses and/or mixing at the reservoir boundaries are likely to sequester two to three times the amount of carbon dioxide expected from non-rock space in the reservoir itself;
- Large quantities (gigalitres per year) of water produced at the surface will need to be disposed of during drying-out of CO₂-based EGS;

- Water production may continue if the EGS reservoir has broad connectivity to other regions underground;
- The simplifications used in this approach could be removed through numerical modelling of the system, and incorporating additional complexity.

In general we expect this to provide a useful overview and starting point for further study on the replacement of water with carbon dioxide in EGS reservoirs.

ACKNOWLEDGEMENTS

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