

Study on influence factors of saline aquifer CO₂ sequestration under the constraint of cap rock

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Abstract. In view of the practical problems faced by the CO₂ sequestration in aquifers, this paper considers the influence of injection rate, water production rate, and other factors on CO₂ injection amount, residual sequestration amount, dissolution sequestration amount, and pressure evolution under the constraint of cap rock breakthrough pressure is studied by using a numerical simulation method, and the sequestration potential is evaluated. The results show that: (1) Water production measures can improve CO₂ injection, dissolution sequestration, and residual sequestration. (2) Low ratio of vertical permeability to horizontal permeability is conducive to the security and stability of CO₂ sequestration in the long term. The research content provides support for the evaluation of CO₂ saline aquifer sequestration potential and field practice.

1. Introduction

CO₂ sequestration plays an important role in achieving carbon peak and carbon neutralization in China. The analysis of CO₂ sequestration potential, and pressure distribution during CO₂ sequestration still has extensive research potential, which is the basis for realizing efficient and massive CO₂ sequestration. Because saline aquifers are widely distributed, they are the most promising research direction for CO₂ geological sequestration^[1]. The process of CO₂ sequestration involves structural sequestration, residual sequestration, dissolution sequestration, and mineralization sequestration, and its sequestration stability is getting higher and higher^[2]. Many scholars have carried out a lot of research on the four mechanisms of CO₂ sequestration. In this paper, the numerical simulation method was used to study the influence of the injection rate and water production rate on the amount of CO₂ injection under the

condition of cap rock breakthrough pressure limit, so as to evaluate the potential of the saline aquifers. The research content provides a theoretical basis for the scheme design of CO₂ sequestration.

2. Physical models and fundamental differential equations

2.1 Physical model of saline aquifers

In this paper, single porosity model is used in the saline aquifers. In order to facilitate understanding, the saline layer is simplified into a two-dimensional model, and the basic parameters of the simulated formation are shown in Table 1. The aquifer thickness is 100 m, and the aquifer length is 500 m. An injection well and production well are set at the left side and right side separately, which are perforated at the bottom, as shown in Figure 1.

Table 1. Basic formation parameters.

Parameters/unit	Value ^[3]	Parameters/unit	Value ^[3,4]
Initial temperature/K	320	Compressibility of water/(MPa ⁻¹)	4.5×10^{-4}
depth/m	1200	depth of gas and fluid contact /m	1150
Porosity of aquifer	0.18	Maximum residual gas saturation	0.4
Initial pressure/MPa	11.8	Horizontal permeability/mD	100
Compressibility of rock/(MPa ⁻¹)	5.8×10^{-4}	Vertical permeability/mD	100

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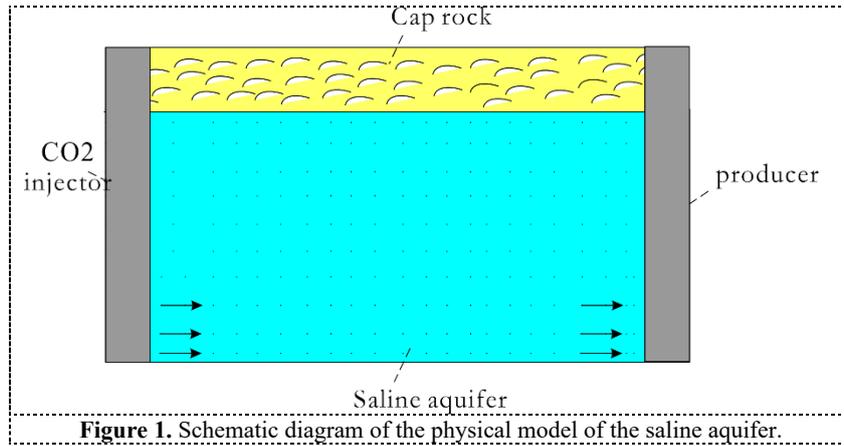


Figure 1. Schematic diagram of the physical model of the saline aquifer.

2.2 Fundamental differential equations

It is assumed that the CO₂ after injection into the formation is supercritical CO₂, and when CO₂ is injected into the brackish water layer, there is a two-phase flow of supercritical CO₂ and water. These two phases satisfy Darcy's law, giving us the equation of motion

$$\begin{cases} v_{jx} = -\frac{k_j}{\mu_j} \frac{\partial p_j}{\partial x} \\ v_{jz} = -\frac{k_j}{\mu_j} \left(\frac{\partial p_j}{\partial z} - \rho_j g \right) \\ j = CO_2^{sc}, w, g \end{cases} \quad (1)$$

Where v is Darcy velocity, $cm \cdot s^{-1}$; p is pressure, 0.1MPa; ρ is the density, $g \cdot cm^{-3}$; g is the acceleration of gravity, $9.8m \cdot s^{-2}$; μ is the viscosity, $mPa \cdot s$.

Mass conservation equation of CO₂ component is :

$$\sum_{r=1}^{n_r} v_{ir} \rho_r - \nabla \cdot \left[\sum_j C_{ij} \rho_j v_{ij} \right] = \sum_j \frac{\partial}{\partial t} \phi C_{ij} \rho_j S_j + q_i \quad (2)$$

Where C_{ij} is the mass fraction of the i component in the phase j ; ϕ is porosity; S is the saturation of phase j ; q_i is the yield of i component per unit volume per unit time.

The saturation constraint equation is :

$$S_w + S_g + S_{CO_2} = 1 \quad (3)$$

Mass fraction constraint equation is :

$$\sum_i^N C_{ij} = 1 \quad (4)$$

Phase equilibrium equation is :

$$\begin{aligned} \frac{C_{ig}}{C_{iCO_2^{sc}}} &= K_{igCO_2^{sc}} \\ \frac{C_{ig}}{C_{iw}} &= K_{igw} \end{aligned} \quad (5)$$

Capillary pressure constraint equation is :

$$p_w = p_{CO_2} - p_{cCO_2w}(S_w) \quad (6)$$

Where, K is equilibrium constant; $p_{cCO_2w}(S_w)$ is capillary pressure; 0.1 MPa.

3. Simulation of CO₂ injection in saline aquifer

CMG-GEM was used to establish the model. The reservoir size is $500m \times 100m \times 5m$, and the number of the saline aquifer grid is $100 \times 20 \times 1$. Injection Wells were set up to inject salt water at a rate of $200,000 m^3 \cdot d^{-1}$ (surface condition) for 4 years. Harvey's Method was used to correlate Henry's constant when the permeability and capillary hysteresis were set at the same time. Figure. 2 shows the distribution of mole fraction in water layer at different simulated time.

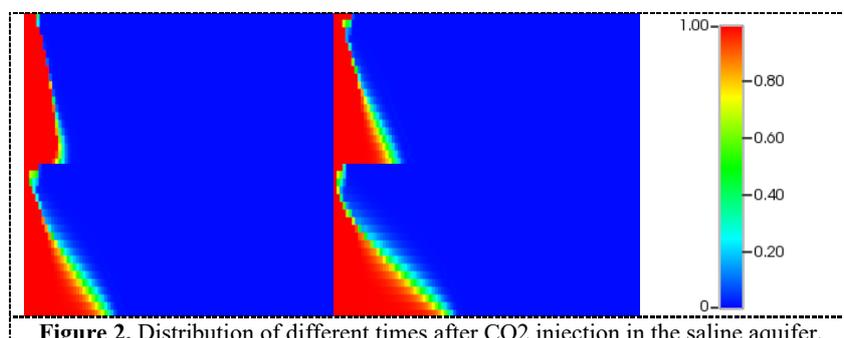


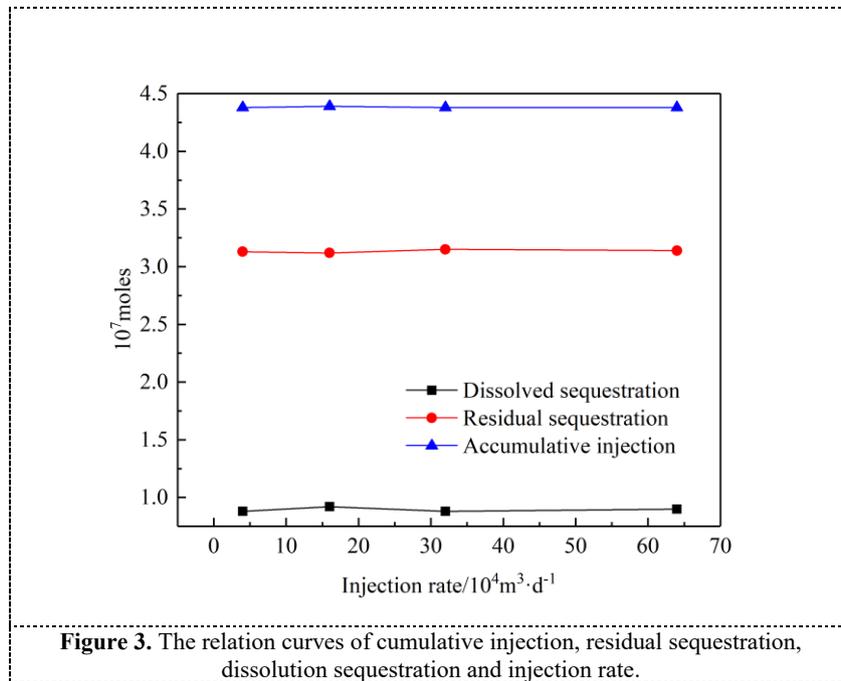
Figure 2. Distribution of different times after CO₂ injection in the saline aquifer.

As can be seen from the figure 2, CO₂ in the saline aquifer will migrate spontaneously due to diffusion after the end of the CO₂ injection. Convective diffusion is an important factor to increase residual and dissolved CO₂ sequestration.

3.1 Effect of injection rate on CO₂ sequestration.

In order to reflect the influence of the sealing ability of cap rock, the breakthrough pressure is set as 8 MPa. For

the initial water pressure of 12 MPa, CO₂ injection was stopped when the bottom-hole pressure of the injection well was set to be greater than 20 MPa in order to avoid over high pressure resulting in cap breakthrough. After injecting 40,000 m³·d⁻¹ (ground), 80,000 m³·d⁻¹ (ground), 160,000 m³·d⁻¹ (ground), and 320,000 m³·d⁻¹ (ground) for 4 years. Under four injection speeds, the relationship curves of cumulative injection amount, residual, dissolution sequestration amount and injection rate are shown in Figure 3.



As shown in Figure 3, after CO₂ injection, due to the hysteretic effect of capillary pressure and permeability, CO₂ mainly concentrated near the wellbore and could not be effectively diffused out. Even if the injection rate was changed, the CO₂ captured near the wellbore could not be migrated horizontally. Figure 4 shows that the injection rate has little effect on cumulative injection, residual, and dissolution sequestration at a maximum bottomhole pressure of 20 MPa, because the pressure limit determines the amount of CO₂ that can be injected. This also shows that whether to consider the cap breakthrough pressure is closely related to the effective migration and sequestration of CO₂.

3.2 Effect of production rate on CO₂ sequestration.

Similarly, when the bottom hole pressure of the injection well is greater than 20 MPa, the condition of CO₂ injection is stopped, and the constant injection rate of CO₂ is 40,000 m³·d⁻¹ (surface). Meanwhile, the pumping rate is 5 m³·d⁻¹, 10 m³·d⁻¹, 25 m³·d⁻¹ and 50 m³·d⁻¹ (surface), respectively. The distribution of CO₂ saturation and mole fraction simulated by numerical simulation software is shown in Figure 4. As can be seen

from the figure, the mole fraction of CO₂ produced a wider lateral diffusion after the injection well was set up. When a wider diffusion range of CO₂ plume is obtained, the contact area between CO₂ and cap rock is increased, which will promote the escape of CO₂ from the area with weak local sealing ability of cap rock. On the other hand, larger contact area will lead to the physical and chemical reaction between cap rock minerals and CO₂, which will dissolve, resulting in the weakening of cap sealing ability. By changing the water production rate of the well, the relationship curves of cumulative injection amount, residual, dissolution sequestration, and injection rate under different water production rates are shown in Figure 5.

As can be seen from the figure, under the limit of the maximum bottomhole pressure of 20 MPa, the greater the water production rate, the greater the amount of CO₂ injection, residual and dissolution sequestration amount are. On the one hand, the production well produces water in the closed saline aquifer, which slows down the increase of water layer pressure and takes longer time to reach 20 MPa, thus increasing the CO₂ injection. On the other hand, the water injection well promotes the convection in the saline aquifer, enlarges the diffusion range of CO₂, and increases the residual CO₂ that can be captured in the pores, thus increasing the residual

sequestration. In addition, the increase of the diffusion range makes the contact area between CO₂ and water

increase, thus increasing the dissolution sequestration of CO₂.

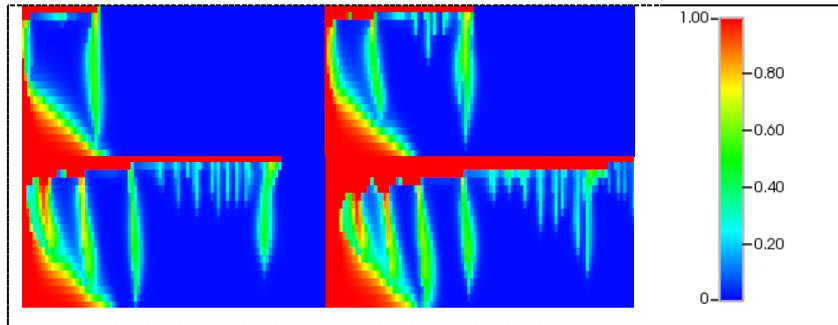


Figure 4. Distribution diagram of mole fraction after CO₂ injection hole pressure injection.

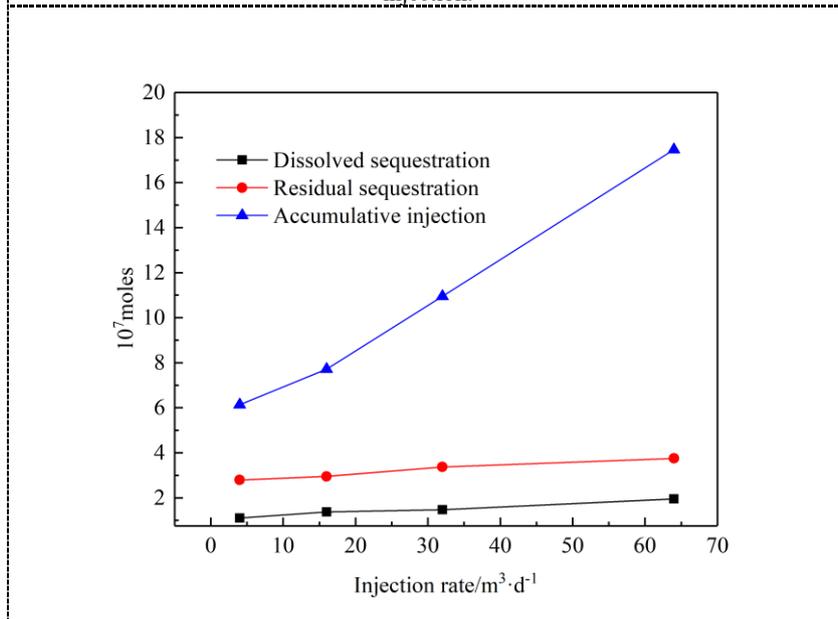


Figure 5. The relation curves of cumulative injection, residual sequestration, dissolved sequestration and production rate.

3.3 Effect of permeability on pressure distribution.

When the vertical permeability is changed to 0.1 times of the horizontal permeability, the vertical pressure conducts slower diffusion and faster horizontal conduction. This is because the vertical conduction

resistance increases and the pressure migrates more laterally, which effectively prevents CO₂ from reaching the top of the water layer and the high pressure at the top of the saline aquifer. Therefore, it is more beneficial to the safety and stability of long-term CO₂ sequestration to select the saline aquifer with the lowest ratio of vertical permeability to horizontal permeability.

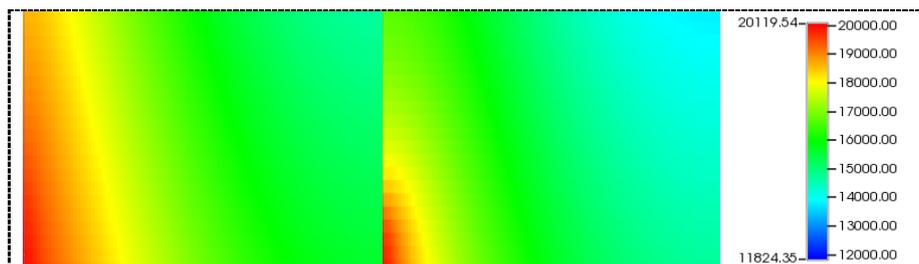


Figure 6. Pressure distribution (10³Pa) diagram of CO₂ injection in same time with different permeability.

4. Conclusion

(1) Under the maximum bottomhole pressure of 20 MPa, CO₂ cannot be migrated effectively due to the hysteresis of capillary force and permeability, and the injection rate has little effect on the cumulative injection amount, residual storage and dissolved storage.

(2) Under the limit of the maximum bottomhole pressure of 20 MPa, the higher the water recovery rate, the slower the rise of pressure, the stronger the convective effect, the larger the pressure CO₂ injection amount, residual and dissolution sequestration;

(3) Strong convection may result in large area contact between CO₂ plume and cap rock, resulting in physical and chemical dissolution reactions, thus weakening the sealing ability of cap rock.

(4) The lowest ratio of vertical permeability to horizontal permeability is more conducive to the safety and stability of long-term CO₂ sequestration.

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