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An Integrated Model for CO_2 Storage Capacity in Shale Gas Reservoirs Considering Gas Leakage

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ABSTRACT

To reduce CO_2 emissions in response to global climate change, depleted shale reservoirs are ideal for long-term carbon storage. However, hydraulic fracturing measures and large injections of carbon dioxide can cause faults and fractures to reactivate, causing gas migration and leakage. In this paper, a partially permeable boundary is introduced to characterize the region where CO_2 leakage occurs. This study proposes a model for predicting CO_2 sequestration potential in novel depleted shale gas reservoirs considering gas adsorption, diffusion, and gas leakage. Furthermore, the multi-scale transport model is solved using Laplace transformation and potential energy superposition and is verified using numerical simulations based on the field data from the Marcellus Shale. The results show that the analytical solutions of the proposed model are in good agreement with the results of conventional numerical simulations. Moreover, shale reservoirs with high Langmuir volume and low Langmuir pressure are ideal for CO_2 storage, with larger CO_2 storage capacity and minor gas leakage. The findings have tremendous significance for the potential utilization of depleted shale gas reservoirs, considering the leakage of CO_2.

Keywords: CO_2 storage, shale gas reservoir, storage capacity, gas leakage and rate transient analysis

NOMENCLATURE

Abbreviations	
BHP	Bottom hole pressure
MFHW	Multiple fractured horizontal wells
Symbols	
a_D	Adsorption index, dimensionless
C_g	Gas compressibility, MPa^{-1}
C_{fD}	Hydraulic fracture conductivity
D_k	Diffusion coefficient, m^2h^{-1}
k_{nf}	Natural fracture permeability, D
L	Leakage ratio, dimensionless
L_f	Hydraulic fracture length, m
m	Pseudo pressure, $MPa^2/(mPa\cdot s)$
N	Number of hydraulic fractures
P	Pressure, MPa
q	Gas flow rate, m^3/d
S	Skin factor, dimensionless
T	Temperature, K
ω	Storage ratio, dimensionless

1. INTRODUCTION

Emissions of greenhouse gases, especially CO_2, are causing severe climate change hazards, threatening simultaneous sustainable social, ecological, and economic development[1]. Thus, reducing CO_2 emissions in response to global climate change has become challenging for all countries worldwide. CO_2 geological storage is a potential and effective method for injecting

CO_2 into different areas, such as hydrocarbon reservoirs[2], underground saline aquifers[3], and unrecoverable coal seams[4].

Shale reservoirs are good candidates for CO_2 storage, which can simultaneously enhance shale gas recovery[5]. However, hydraulic fracturing and massive injection could trigger micro-seismic events and result in fault reactivation, allowing gas leakage flow paths. Therefore, gas leakage is the crucial factor that should be considered in the CO_2 storage capacity evaluation.

Currently, numerous researches on the carbon storage capacity of shale gas reservoirs have been reported. Based on the history matching of field production data, Xu[6] investigated the impact of geomechanics on carbon storage capacity via a coupled hydrodynamic and poromechanical model. Compared with numerical simulation, pressure transient analysis (PTA) and rate transient analysis (RTA) can provide a fast method to evaluate carbon storage capacity, monitor and forecast the injection performance[7].

In this paper, a new method based on RTA is proposed for carbon geo-sequestration capacity prediction. A partially permeable boundary is introduced to characterize permeable faults and fractures. The analytical solution of the CO_2 storage capacity model in shale gas reservoir considering gas adsorption, diffusion and leakage is obtained by potential superposition and Laplace transform and verified by the field data of Marcellus shale. The proposed methodology can monitor, forecast the injection performance and evaluate the degree of gas leakage, which could provide a reference for CO_2 injection and risk evaluation.

2. METHODOLOGY

2.1 Physical model

The physical model of a multiple fractured horizontal well (MFHW) located in the center of a cylinder reservoir with gas leakage is shown in Fig. 1 The assumptions of the physical model are as follows:

(1) The Shale reservoir is homogeneous, and the temperature is identical.

(2) CO_2 diffusion in the shale matrix satisfies Knudsen diffusion and the adsorption/desorption of gas molecules satisfies Langmuir adsorption model.

(3) Gravity and capillary forces are ignored.

(4) The conductivity of hydraulic fractures is finite.

(5) Gas flow in the shale matrix satisfies transient diffusive flow and is described by Fick's second law.

2.2 Mathematical model and solutions

To calculate the CO_2 storage potential in shale gas reservoirs considering gas leakage, it is necessary to obtain an analytical solution for BHP at a constant injection rate. First, a point-source solution for a well in an infinite reservoir is performed, taking into account gas adsorption, diffusion, and leakage. Then, combined with the superposition principle, the analytical solution can be obtained. Finally, based on the relationship between pressure and injection rate, a prediction of CO_2 storage capacity can be obtained. The definitions of dimensionless variables are summarized in Appendix A.

<u>2.2.1 Point source solution for the CO_2 storage capacity</u>

(1) Matrix system

The CO_2 flow in shale matrix is in the form of Knudsen diffusion which is driven by gas concentration difference. The continuity equation of matrix system in Laplace domain can be written as:

$$\frac{1}{r_{mD}^2}\frac{d}{dr_{mD}}\left(r_{mD}^2\frac{d\overline{V_D}}{dr_{mD}}\right)=\frac{s}{D_{kD}}\overline{V_D} \tag{1}$$

where $\overline{V_D}$ is the dimensionless CO_2 concentration in the Laplace domain, D_{kD} is the dimensionless diffusion coefficient. Considering the symmetry of the shale matrix, it is assumed that there is no flow in the center of the matrix. Thus, the inner boundary condition in the Laplace domain can be expressed as:

$$\frac{d\overline{V_D}}{dr_{mD}}|_{r_{mD}\to 0}=0 \tag{2}$$

The outer boundary and auxiliary conditions are shown as follows:

$$\overline{V_D}|_{r_{mD}=R_{mD}}=\overline{V_{ED}} \tag{3}$$

$$\frac{s}{3D_{kD}}\overline{V_D}=\frac{d\overline{V_D}}{dr_{mD}}|_{r_{mD}=1} \tag{4}$$

where $\overline{V_{ED}}$ is the dimensionless CO_2 concentration in the natural fracture system in the Laplace domain. Combined with Eq.(1)-Eq.(4), the particular solution of the CO_2 concentration in the matrix system can be obtained:

$$s\overline{V_D}=3aD_{kD}\overline{\Delta m}\left[\sqrt{\frac{s}{D_{kD}}}coth\left(\sqrt{\frac{s}{D_{kD}}}\right)-1\right] \tag{5}$$

where *a* represents adsorption index.

(2) Natural fracture system

CO_2 flows in form of seepage in the natural fracture system. The continuity equation, the initial, inner boundary and outer boundary conditions of the natural fracture system with dimensionless variables in Laplace domain can be expressed as follows:

$$\frac{d^2\overline{\Delta m}^2}{dr_{nfD}^2}+\frac{1}{r_{nfD}}\frac{d\overline{\Delta m}}{dr_{nfD}}=s\omega\overline{\Delta m}+\frac{1-\omega}{H}s\overline{V_D} \tag{6}$$

$$\overline{\Delta m}|_{r_{nfD},t_D=0}=0 \tag{7}$$

$$\frac{k_{nf}T_{sc}hr_{nfD}^2}{1.842\times10^{-3}P_{sc}T}\frac{d\overline{\Delta m}}{dr_{nfD}}|_{r_{nfD}\to 0}=-\frac{\hat{q}}{s} \tag{8}$$

$$\overline{\Delta m}|_{r_{nfD\to\infty},s=0}=0 \tag{9}$$

where ω is the storage ratio. The particular solution of the point source in the natural fracture system can be obtained as:

$$\overline{\Delta m}=\frac{1.842\times10^{-3}P_{sc}T}{k_{fi}T_{sc}hs}\hat{q}\frac{e^{-r_{nfD}\sqrt{sf(s)}}}{r_{nfD}} \tag{10}$$

2.2.2 Solution for shale reservoir with CO_2 leakage

For shale reservoirs with CO_2 leakage, the continuity equation, initial and boundary conditions can be described by Eq.(13) – Eq.(17).

$$\frac{1}{r_{cD}}\frac{d}{dr_{cD}}\left(r_{cD}\frac{d\overline{m_D}}{dr_{cD}}\right)+\frac{d^2\overline{m_D}^2}{dz_D^2}=sf(s)\overline{m_D} \tag{11}$$

$$\overline{m_D}|_{t_D=0}=0 \tag{12}$$

$$\lim_{\varsigma_D\to0}\left(\lim_{r_{cD}\to0}\frac{2}{\varsigma_D}\int_{z_{wD}-\frac{\varsigma_D}{2}}^{z_{wD}+\frac{\varsigma_D}{2}}r_{cD}\frac{d\overline{m_D}}{dr_{cD}}dz_{wD}\right)=-\frac{\hat{q}}{q_{sc}s} \tag{13}$$

$$\frac{d\overline{m_D}}{dz_D}|_{z_D=0,1}=0 \tag{14}$$

$$r_{cD}\frac{d\overline{m_D}}{dr_{cD}}|_{r_{cD}=r_{12D}}=-\frac{L}{s} \tag{15}$$

where r_{cD} is the dimensionless radius in the cylindrical coordinate. Referring to Ozkan's work[8], the particular solution for a cylinder reservoir with CO_2 leakage can be expressed as:

$$\overline{m_D}=U+R \tag{16}$$

where U and R are the point source solutions for the wells in a laterally infinite reservoir of finite thickness.

The BHP of MFHW with finite conductivity in the Laplace domain can be obtained by the principle of potential superposition and can be written in the form of an *N*+1 order matrix:

$$DX=u \tag{17}$$

Taking into account well storage and the skin effect, the BHP can be calculated as:

$$\overline{m_{wDC}}=\frac{s\overline{m_{wD}}+S}{s\{1+sC_D[s\overline{m_{wD}}+S]\}} \tag{18}$$

2.2.3 CO_2 storage capacity calculation

The injection rate of MFHW under constant injection pressure can be obtained as:

$$\overline{q_{injD}m_D}=\frac{1}{s^2} \tag{19}$$

After Stehfest numerical inversion, the dimensionless injection rate q_{injD} can be transformed to the real domain. The corresponding injection time can be obtained as:

$$t^n=t_D^n\frac{\mu\wedge h^2}{3.6\times24k_{nf}} \tag{20}$$

The CO_2 storage capacity can be calculated as follows:

$$N_{inj}=\sum_{n=1}^{N}(t_i-t_{i-1})q_{inj}^n \tag{21}$$

3. RESULTS AND DISCUSSIONS

3.1 Case Study

The Marcellus Shale is the lowest formation of the Middle Devonian-era Hamilton Group located in the Appalachian basin[9]. The matrix permeability of Marcellus shale is pretty low, which can greatly prevent the CO_2 leakage. In addition, the pressure and temperature profiles are similar to saline aquifers, so the Marcellus Shale formation is an ideal candidate for CO_2 storage. The parameters of the shale reservoir are shown in Table 1.

Table 1 Parameters of reservoir, well and CO_2 in the Marcellus Shale

Item	Properties	Value	Unit
Reservoir	Reservoir temperature	328	K
	Porosity	0.142	Dimensionless
	Reservoir thickness	29	m
	Fracture permeability	8×10^{-4}	D
	Drainage radius	1500	m
	Depleted pressure	1.2	MPa
	Leakage ratio	0.05	Dimensionless
Well	Hydraulic fracture half length	137	m
	Hydraulic fracture stages	4	
	Fracture number	4	
	Well length	1280	m
	Constrained pressure	8	MPa
	Wellbore storage	1	
	Skin factor	0.1	
	Hydraulic fracture conductivity	10pi	
CO_2	Constant injection rate	105	m^3/d
	Diffusion coefficient	10^{-8}	m^2/s
	Compressibility	0.048	1/MPa
	Viscosity	0.01	mPa·s
	Gas compressibility factor	0.8	Dimensionless
	Langmuir pressure	20.34	MPa
	Maximal adsorbed gas	2.636	m^3/ton
	Adsorption index	0.6844	Dimensionless

3.1.2 Numerical verification

KAPPA, a commercial numerical simulator, is applied to verify the proposed model of CO_2 storage capacity for shale reservoirs. In the Marcellus Shale, the control zone of a multi-fractured horizontal well, a cylindrical reservoir with a radius of 1500 m. In addition, a numerical model is established by KAPPA to verify the accuracy of the injection curve calculated by the proposed methodology.

Numerical verification results are shown in Fig. 1. As can be seen from the figure, except for some tiny errors caused by the correction function in the intermediate stage, the results calculated by the method proposed in this paper match well with KAPPA, which shows that the proposed methodology is reliable. After verifying the reliability of the proposed model, a sensitivity analysis can be performed based on this methodology.

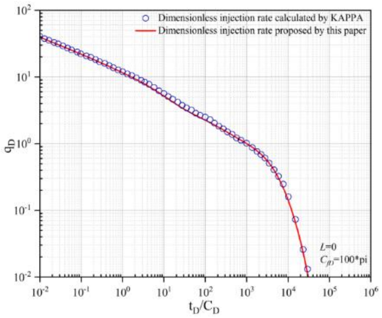
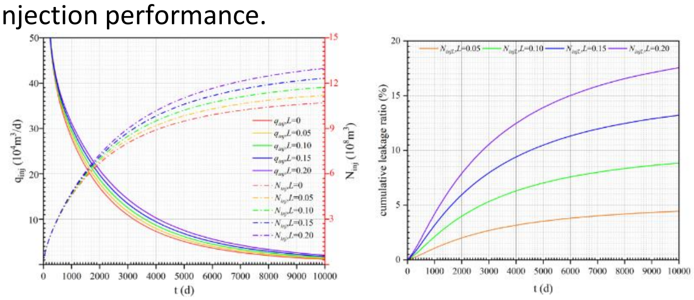


Fig. 1. Comparison of the proposed model with KAPPA

3.2 Sensitivity analysis

3.2.1 Leakage ratio

The leakage rate reflects the capture capacity of the reservoir and is an essential parameter for assessing the risk of CO_2 leakage during the injection. CO_2 injection rate and cumulative injection volume curves are shown in Fig. 2 (a), and cumulative leakage ratio curves are shown in Fig. 2 (b). The cumulative injection volume increases with the leak rate, especially in the late injection period. A higher leak rate indicates that more of the injected carbon dioxide flows through the boundary rather than remaining in the reservoir. It can also be seen that the cumulative leak ratio increases gradually with the injection time. In the late injection period, the cumulative leakage rate stabilized and tended to the boundary leakage rate. Therefore, the boundary properties must be investigated before injection, and the risk of CO_2 leakage can be assessed by monitoring CO_2 injection performance.

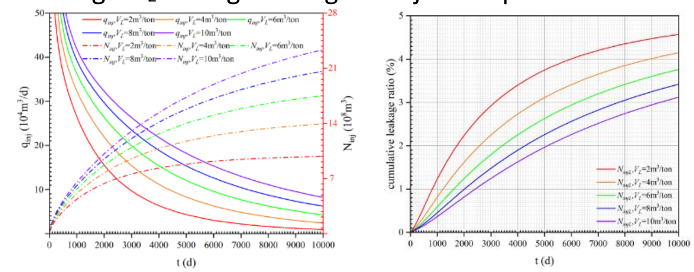


(a) (b)

Fig. 2 (a) CO_2 injection rate and cumulative injection volume curves (b) Cumulative leakage ratio curves with variable leakage ratio

3.2.2 Langmuir volume

Langmuir volume, V_L, is a crucial parameter that determines maximum amount of gas adsorbed on the surface of shale matrix particles and has a significant impact on the adsorption capacity of shale matrix. Langmuir volume changes from 2 m^3/ton to 10 m^3/ton, and the results are shown in Fig. 3. It can be seen that the injection rate and cumulative injection volume are positively correlated with the Langmuir volume, while the cumulative leak rate is negatively correlated with the Langmuir volume. This is because the adsorption capacity of the shale matrix increases with the increase of the Langmuir volume, and more CO_2 molecules are adsorbed to the surface of the matrix, which delays the rise of the reservoir pressure and weakens the influence of the boundary, resulting in a decrease in the leakage rate. It shows that the reservoir with a larger Langmuir volume has a larger adsorption capacity, significantly reducing CO_2 leakage during the injection process.

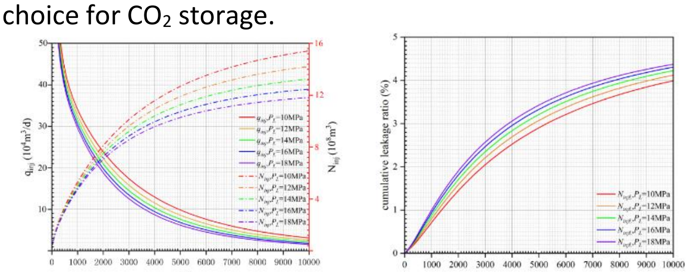


(a) (b)

Fig. 3 (a) CO_2 injection rate and cumulative injection volume curves (b) Cumulative leakage ratio curves with variable Langmuir volume

3.2.3 Langmuir pressure

Langmuir pressure is another critical parameter determining the difficulty of adsorption and significantly affects the adsorption capacity. As shown in Fig. 4, the injection rate and cumulative injection amount decrease as the Langmuir pressure increases. Although the maximum volume of adsorbed gas remains unchanged at a fixed Langmuir volume, the difficulty of CO_2 adsorption on the surface of matrix particles increases with the increase of Langmuir pressure, strengthening the influence of boundary and increasing the cumulative leakage ratio. It is well known that high Langmuir pressures are more suitable for production because methane molecules are easily desorbed from the surface of matrix particles to sustain production. However, unlike shale gas reservoir development, depleted shale gas reservoirs with low Langmuir pressure are the first choice for CO_2 storage.



(a) (b)

Fig. 4 (a) CO_2 injection rate and cumulative injection volume curves with variable Langmuir pressure (b) Cumulative leakage ratio curves

4. CONCLUSIONS

In this paper, the analytical solution of the CO_2 storage capacity of MFHW with finite conductivity in bounded shale gas reservoir considering gas leakage is derived and verified. Based on the analytical solution of MFHW and combined with parameters from Marcellus shale, the influence of several crucial factors on injection performance and CO_2 leakage is well analyzed. Conclusions are summarized as follows:

(1) The calculation results match well with the numerical simulation. Besides, CO_2 leakage risk can be evaluated by the proposed method.

(2) With the increased leakage ratio, more proportion of injected CO_2 flows through the boundary, aggravating the risk of injected CO_2 leakage.

(3) Langmuir volume and Langmuir pressure are crucial parameters that determine the CO_2 storage capacity. Depleted shale gas reservoirs with high Langmuir volume and low Langmuir pressure are ideal candidates for CO_2 storage.

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APPENDIX A. DEFINITIONS OF DIMENSIONLESS VARIABLES

Dimensionless parameters in the diffusion and seepage model are defined as follows:

Dimensionless CO_2 concentration, V_D

$$V_D = \Delta V = V - V_i \tag{A-1}$$

Dimensionless Knudsen diffusion coefficient, D_{kD}

$$D_{kD} = \frac{D_K \mu \Lambda h^2}{3.6 k_{nf} R_m^2} \tag{A-2}$$

where Λ satisfies:

$$\Lambda = \phi C_g + \frac{k_{nf} h}{1.842\times10^{-3} q_{sc} \mu} \tag{A-3}$$

Dimensionless time, t_D

$$t_D = \frac{3.6 k_{nf} t}{\mu \Lambda h^2} \tag{A-4}$$

Storage ratio, ω

$$\omega = \frac{\phi C_g}{\Lambda} \tag{A-5}$$

Dimensionless adsorption index, a_D

$$a_D = \frac{3.684\times10^{-3} p_{sc} q_{sc} T}{k_{fi} h T_{sc}} \frac{V_L P_L \mu Z}{(P_L+P)(P_L+P_i)(P_i+P)} \tag{A-6}$$

Dimensionless hydraulic fracture conductivity, C_{fD}

$$C_{fD} = \frac{k_{hf} w_f}{k_{nf} L_f} \tag{A-7}$$

Dimensionless pseudo-pressure, m_D

$$m_D = \frac{k_{nf} h T_{sc}}{3.684\times10^{-3} p_{sc} q_{sc} T} (m - m_i) \tag{A-8}$$

Dimensionless injection rate under constant injection pressure,

$$q_D = \frac{3.684\times10^{-3} p_{sc} q_{sc} T}{k_{nf} h T_{sc} (m_w - m_i)} \tag{A-9}$$