A Multi-Continuum Multi-Component Model for Enhanced Gas Recovery and CO_2 Storage in Fractured Shale Gas Reservoirs

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Abstract. Shale gas reservoirs have been proposed as feasible choices of location for injection of CO_2 because this method could enhance recovery of natural gas resources, while at the same time sequester CO_2 underground. In this paper, a fully coupled multi-continuum multi-component simulator which incorporates several transport/storage mechanisms is developed. Knudsen diffusion and gas slippage are included in the flow model. An extended Langmuir isotherm is used to describe the adsorption/desorption behavior. In addition, a hierarchical approach which integrates EDFM with MINC concept is adopted. Fully implicit scheme is applied for discretizing fluid equations. Different injection strategies including huff-n-puff scenario are evaluated to provide insights for optimizing production of multi-fractured horizontal well. Results show that CO_2 injection can be an effective approach with great application potential for enhancing shale gas recovery.

Introduction

There is recent interest in the utilization of shale gas reservoirs as promising targets for Enhanced Gas Recovery (EGR) processes; in EGR, CO_2 is injected to simultaneously enhance gas production while sequestering CO_2 underground. [1] demonstrated that injection of CO_2 into gas shale for EGR is feasible because of the greater sorption affinity for CO_2 than methane in organic-rich rock. Due to the ultra-low matrix permeability, the economic development of shale gas reservoirs depends much on effective stimulation treatments through multi-stage hydraulic fracturing of horizontal wells. Accurate modeling of gas production is very challenging, because the reservoirs comprise complex fracture networks with multiple orientations and length after hydraulic fracturing. In order to obtain the balance between accuracy and computational efficiency, we propose a multi-continuum method which integrates embedded discrete fracture model (EDFM), dual-porosity and MINC (multiple interacting continua) concept. The hybrid model includes three domains: matrix, major hydraulic fractures and large-scale natural fractures (described by EDFM), and micro-fractures in SRV region which are modeled by MINC approach. The method developed could explicitly describe the dominant role of large-scale fractures as flow conduits, and simulate the natural fracture networks which connect the global flow in stimulated areas of shale gas reservoirs.

Physical Modeling of Flow and Transport

We apply the single-phase multi-component flow model in this work. The model assumes gas is stored in natural and primary fractures as free phase, while in matrix as both free and adsorbed phase. In an isothermal system containing n_c mass components, subject to gravity effect, non-darcy flow and adsorption, n_c mass-balance equations are needed to fully describe the system (matrix or fracture). The general governing equations considering various interactions between continuums:

$$\frac{\partial}{\partial t}\{\phi\rho_g x_i + (1-\phi)m_i\} = \nabla\cdot(\rho_g x_i \upsilon) + q_i^w + q_i^{conn} \tag{1}$$

Darcy's Law is used to describe the gas flow:

$$\upsilon = \frac{k}{\mu}(\nabla p - \gamma g \nabla D) \tag{2}$$

The mole of component i adsorbed in unit formation volume, (only for matrix):

$$m_i = \rho_R \rho_{gs} V_i \tag{3}$$

Where ϕ is the porosity of matrix or fractured media; k is the apparent permeability of matrix or permeability of fractures; μ is the gas viscosity; γ is the mass density of gas mixture; ρ_g is the gas molar density; x_i is the component mole fraction; ρ_R is the rock bulk density; ρ_{gs} is the gas molar density at standard condition; V_i is the adsorption isotherm function; q_i^w is the source/sink term of component i; q_i^{conn} is the flux terms of component i between continuums.

Knudsen Diffusion and Slip Flow. Gas flow in shale gas reservoirs cannot be described simply by Darcy's law because of the small pores that are at the scale of nanometers [2]. The total flux of gas flow through nanopore is the combination of advection due to pressure forces and Knudsen diffusion, and the advective term was corrected for accounting slip flow. Then the final expression for the apparent permeability of component i is (only considered in matrix):

$$k_{app} = \frac{\phi_m}{\tau}\left\{\frac{2r\mu}{3RT\rho_g}\left(\frac{8RT}{\pi M_i}\right)^{0.5} + \frac{r^2}{8}\left[1 + \frac{\mu}{pr}\left(\frac{2}{\alpha} - 1\right)\left(\frac{8\pi RT}{M_i}\right)^{0.5}\right]\right\} \tag{4}$$

Where r is the pore radius; R is the gas constant; T is the absolute temperature; M_i is the molar weight of component i; α is the tangential momentum accommodation coefficient; τ is the tortuosity of porous medium.

Multi-component Adsorption and Desorption. Because CO_2 is preferentially adsorbed over CH_4, the competitive gas adsorption will play a considerable role in CO_2-EOR process for shale gas reservoirs. An extended Langmuir isotherm which describes the fractional surface coverage of each component is used for describing the multi-component adsorption/desorption behavior. The standard volume of component i adsorbed per unit rock mass can be expressed as:

$$V_i = \frac{V_{L,i}(px_i) / P_{L,i}}{1 + \sum(px_i / P_{L,i})} \tag{5}$$

Where $V_{L,i}$ is the Langmuir volume of component i (the maximum adsorption capacity at a given temperature), and $P_{L,i}$ is the Langmuir pressure of component i (the pressure at which the adsorbed gas content is equal to $V_{L,i} / 2$).

Numerical Model and Simulation Approach

The control-volume finite-difference formulation (CVFD) which is very flexible for handling interactions between various kinds of continua is applied for discretizing fluid equations. Time discretization is carried out using a fully implicit scheme.

Control-Volume Finite-Difference Scheme. The Control-Volume approach provides a general spatial discretization scheme that can represent a three-dimensional domain using a set of discrete meshes. The general discrete nonlinear equations for gridblock i of component c can be written as:

$$\frac{V_i}{\Delta t}\left\{\left(\phi\rho_g x_c\right)^{n+1} + m_c^{n+1} - \left(\phi\rho_g x_c\right)^n - m_c^n\right\} = \sum_{s=1}^{ns} Flux_{ij}^{n+1} - Q_{i,c}^{n+1} \tag{6}$$

The well term for gridblock i of component c can be written as follows. If is injector, ρ_g and x_c denote gas molar density and molar fraction of component c in the wellbore.

$$Q_{i,c} = WI\{\lambda\rho_g x_c(p_i - p^W)\} \tag{7}$$

The molar rate of component c exchanged through computational volume i and j:

$$Flux_{ij} = T_{ij}\left(\lambda\rho_g x_c \Delta\Phi\right)_{ij}^{n+1} \tag{8}$$

Where V_i is the bulk volume; T_{ij} is the transmissibility of the connection; λ is the flow mobility, which is k/μ; ns is the number of connections for gridblock i; WI is the well index; The flow potential between gridblock i, j is:

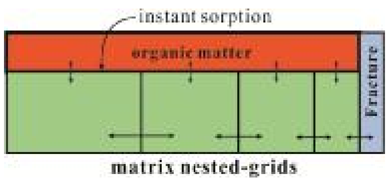
$$\Delta\Phi_{ij} = \Delta p - \gamma_{ij} g \Delta D \tag{9}$$

Hybrid Method for Handling Fracture Networks. Because of the ultra-low matrix permeability in shale formations, it is inaccurate to treat fracture-matrix flow as pseudo-steady state. Therefore MINC method was established to modify traditional dual-continuum models for treating the transient interaction between matrix and fractures in a realistic way [3]. The key aspect of MINC model is the generation of computational meshes by sub-dividing each matrix cell into a series of nested sub-cells. We apply a coupled MINC model in the developed simulator for incorporating storage and transport mechanisms of shale matrix. Advection and diffusion are considered in the gas flow, and instant sorption model represented as source-sink term is used for desorption process. Fig. 1 shows the schematic for the coupled process of gas flow. We also develop the preprocessing code for computing geometric parameters of the MINC model from the specification of fracture spacing L, aperture δ, and volume fractions f_i occupied by the interacting continuums. We assume that $i = 1$ refers to the outer fracture continuum, then can obtain volume fraction of fracture from L and δ:

$$f_1 = [L^3 - (L - \delta)^3] / L^3 \approx 3\delta / L \tag{10}$$

The parameters A_{ij}, d_{ij} and V_i needed for computing the accumulation terms and transmissibility of connections can be derived subsequently [3]. It should be noted that the fracture permeability need conversion to effective permeability when computing the connections between fractures or with other continuums. The coefficient should be multiplied is:

$$\beta = [L^2 - (L - \delta)^2] / L^2 \approx 2\delta / L \tag{11}$$



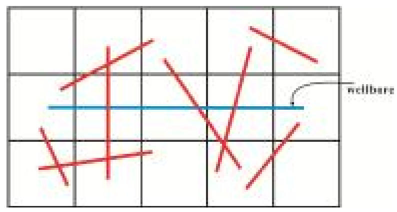


Fig.1 Coupled gas flow in MINC model Fig.2 EDFM with fractures network intersected by horizontal wellbore

Hydraulic fractures in shale gas reservoir are better handled by the discrete fracture model (DFM). [4] developed a novel method called embedded discrete fracture model (EDFM), which is very flexible and computational efficient for simulating complex fractures network. EDFM apply the concept of wellbore index (WI) to derive the transfer index between fracture and matrix gridblock. Fig. 2 shows an EDFM example of fractures network intersected by horizontal wellbore.

We propose a hybrid model to provide more flexibility for the communication between explicit "primary" fracture and natural fracture network because the dual-continuum concept we applied in the reservoir. Fig. 3 illustrates the connection list of continua in computational domain for a simple scenario. [4] assumed that the pressure around a fracture is linearly distributed, and with this approximation the average normal distance from the fracture in the gridblock can be computed as:

$$\langle d \rangle = \frac{\int \vec{n} \cdot x dS}{S} \tag{12}$$

Thus the transmissibility is:

$$T_{ij} = \frac{A_{ij}}{\langle d \rangle} \tag{13}$$

Where $\vec{n}$ is the unit normal vector; x is the distance from the fracture; dS and S are the areal element and area of the gridblock, respectively; A_{ij} is the fracture surface area in the gridblock.

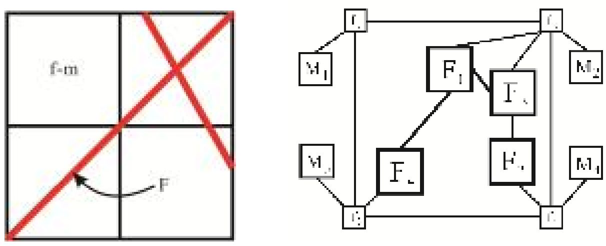


Fig.3 The example of connection list for EDFM coupled with MINC

Simulation Results and Discussions

Single-well Model. A base model is constructed to perform simulation studies for a single horizontal well with multiple hydraulic fractures in shale gas reservoir. The reservoir comprises a horizontal well with 4 stages hydraulic fractures, and the stimulated reservoir volume (SRV) region is described by the MINC model. The parameters assumed for the model are summarized in Table 1. The thermodynamic and adsorption properties of the components used for the simulation studies are summarized in Table 2.

Table 1. Parameters of the base model

Parameter	Value	Unit	Parameter	Value	Unit
Reservoir dimensions (x,y,z)	800, 500, 30	m	Matrix Compressibility	1.0e-10	1/Pa
Gridblock size (x,y,z)	20, 20, 10	m	Fracture Compressibility	1.0e-8	1/Pa
Initial reservoir pressure	12	MPa	Natural fracture permeability	5.0e-16	m^2
Temperature	423	K	Natural fracture spacing	5	m
Matrix porosity	0.1		Hydraulic fracture permeability	1.0e-13	m^2
Fracture porosity	0.5		Hydraulic fracture half-length	100	m
Nanopore radius	3.5e-9	m	Horizontal wellbore length	500	m
Fracture width	0.01	m	Production BHP	5	MPa
Rock density	2500	kg/m^3			

Table 2. Thermodynamic and adsorption properties of the components

	$P_c\ (MPa)$	$T_c\ (K)$	ω	P_L	$V_L\ (m^3/kg)$	$\rho_{gs}\ (kg/m^3)$
CH_4	4.6	190.6	0.011	6.7	0.021	0.71
CO_2	7.4	304.1	0.224	3.4	0.062	1.96

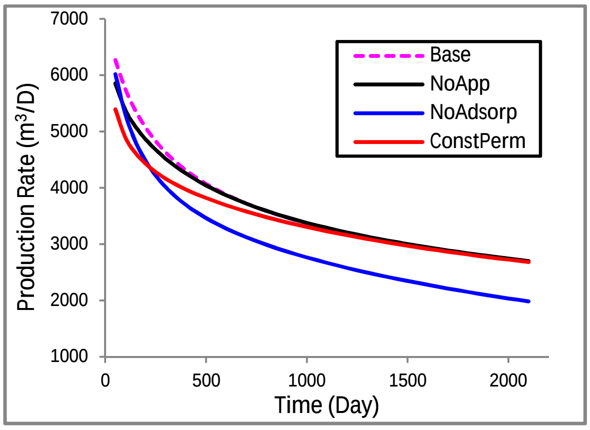


Fig.4 Effect of matrix factors on production rate

We study the effect of adsorption/desorption and apparent permeability on the well production rate. We compare the results of other 3 cases with the base model: without apparent permeability, without adsorption and setting matrix permeability as constant value of 0.5e-20m^2. Fig. 4 shows the simulated production rate of the 4 cases during the 2100 days production period. We can see that apparent permeability only has impact on the early production period, probably because the spacing of the natural fractures is small ($5m$). If matrix permeability becomes very low (0.5e-20m^2), considerable reduction of the production rate will still occur. In addition, Fig. 4 illustrates that gas desorption could have significant effect on well performance. As the reservoir pressure decreases, more adsorbed gas is released from organic rock and produced.

Gas Injection Model for EGR. The competitive adsorption mechanism is expected to play a major role during CO_2-EGR process in shale gas reservoirs. In this work, a reservoir model with two parallel horizontal wells intersected by complex network of primary fractures is established, and simulation studies are performed to investigate the feasibility of EGR through CO_2 injection. The Injection BHP is 16 MPa. The schematic of the model is shown in Fig. 5.

We first perform a simulation without injector, then two cases with regular hydraulic fractures pattern (5 stages, $100m$ half-length) and complex network of primary fractures for the injector are ran and compared to examine the effect of well injectivity on CO_2 sequestration and methane recovery. The total production period is 3500 days, and the model start injecting CO_2 after 700 days. The cumulative methane production and CO_2 injection of the three cases are shown in Fig. 6. The figures illustrate that the methane recovery improve to some extent through CO_2 injection, and as injection ability increases the increment becomes larger. Fig. 7 shows the pressure distribution of fracture continuum in the "complex" model after 2100/3500 days. Large quantities of CO_2 sequestrated indicate that shale gas reservoirs could be good candidate for reducing carbon emission in the future.

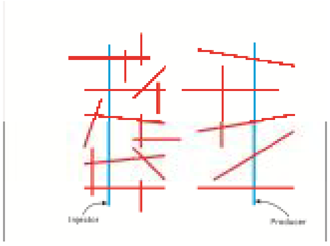


Fig.5 The schematic of gas injection model

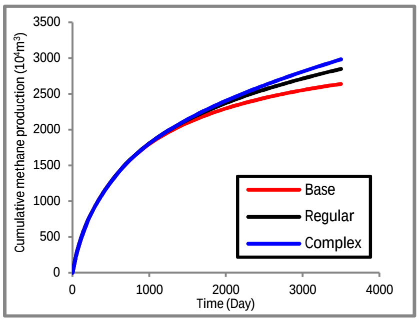


Fig.6(a) Cumulative methane production of the three cases

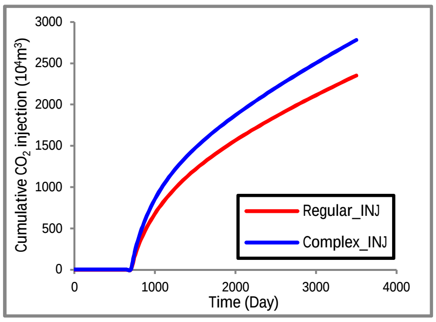


Fig.6(b) Cumulative CO_2 injection of the two cases

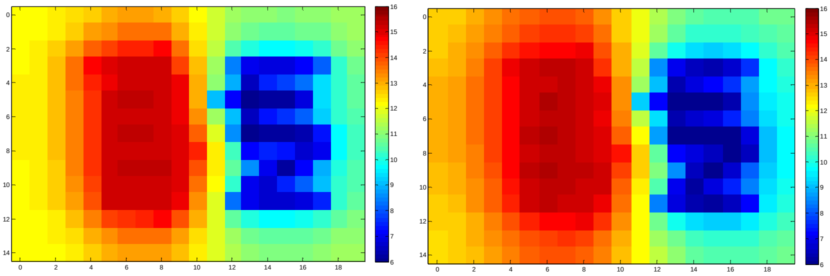


Fig.7 Pressure distribution of fracture continuum in "complex" model after 2100/3500 days

Summary

In this work, we develop a multi-continuum simulator that incorporates the effects of Knudsen diffusion, gas-slippage and multi-component sorption for CO_2-EGR process in fractured shale gas reservoirs. We implement a novel method that integrates EDFM with MINC for successfully simulating the complex fracture networks. We conduct modeling studies to investigate the feasibility of CO_2 injection for carbon sequestration and enhanced methane recovery in shale gas reservoirs.

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