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Pressure-transient analysis of CO_2 flooding based on a compositional method

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ABSTRACT

To find a reliable and inexpensive method to estimate miscibility and other reservoir parameters, as well as to monitor the CO_2 flood progress, this paper proposed a transient flow model based on a compositional model that considers the wellbore storage effect, skin factor and multiple-contact processes. The model solution is obtained with the finite volume method and by performing pressure transient analysis. The results demonstrate that the pressure derivative curve of the swept area radial flow rises first and later declines slightly; the pressure derivative curve of the unswept area radial flow rises first and later becomes flat. The CO_2 flood front can be recognized when the derivative curve begins to rise after it declines slightly in the swept area radial flow regime. A numerical well test interpretation method can be established based on the model used in this paper to estimate the permeability, miscibility, and formation damage and to monitor the CO_2 flood progress.

1. Introduction

CO_2 Enhanced Oil Recovery (EOR) is the green way to produce oil as it can recover the stranded or trapped oil by injecting the carbon emissions (CO_2) from fossil-fueled power plants into the reservoir which can mitigate the greenhouse effect simultaneously (Gozalpour et al., 2005; NETL, 2010, 2006; Malik and Islam, 2000; Holtz et al., 2001; Jaramillo et al., 2009). This proven method has promising prospects as a result of technological advances, economic improvements, and environmental needs, and a study (NETL, 2011) conducted by DOE found that Next Generation CO_2 EOR can provide 137 billion barrels of additional technically recoverable domestic oil.

As the breakthrough of gas usually occurs, which leads to lower oil recovery and failure of the CO_2 storage, useful methods should be found to monitor the CO_2 flood progress and estimate the miscibility. The most common method is seismic monitoring (Araman et al., 2008; Kendall et al., 2003; Terrell et al., 2002), as Time-Lapse and Multicomponent seismic data analysis is an effective tool for monitoring CO_2 injection through the detection of changes in reservoir properties, such as porosity and fluid distribution. Although this method has been demonstrated to be accurate, it is expensive and not convenient enough to be used frequently. Another method is the Material Balance Equations (MBE) model (Tian and Zhao, 2008), which is convenient to use and inexpensive, but it is hard to obtain accurate results with this method, as it has many simplifications and assumptions.

Well testing technology is commonly (Lee, 1982; Ozkan, 2001; Stratton, 2005, 2006; Zheng and Corbett, 2005; Yao and Wu, 2009; Fan et al., 2015) used to estimate the reservoir parameters and is a promising method to solve the above problem. MacAllister (1987) presented a procedure based on a three region composite model to analyze the CO_2 and enriched-gas injection and production wells with emphasis on the real gas pseudo approach. Tang and Ambastha (1988) presented a three region analytical radial composite model to analyze the CO_2 pressure transient; Su et al. (2015) established a three-region composite transient pressure analysis model for CO_2 flooding, which considered the skin and storage effects of the well. Although the analytical composite model can describe the trend of the pressure change, it used too many simplifications and assumptions, which led to imprecise estimation of the parameters.

In order to solve the above problem, an accurate model should be built and subsequently used to analyze the pressure transient of CO_2 flooding. This paper describes a transient flow model that is

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based on a compositional model which considers the effects of wellbore storage, skin effect and multiple-contact processes. The solution to the transient flow model is based on the finite volume method (FVM) followed by analysis of the transient pressure, which is used to divide the flow regime and find the CO_2 flood front via the pressure derivative curve. In addition, the compositional transient flow model presented in this paper can provide effective technical support for the monitoring of CO_2 flood progress and estimation for reservoir parameters.

2. Model description

This section presents the mathematical model for the numerical simulation and the numerical well test, which can be used to describe the multiple-contact process involving interactions between the injected CO_2 and the reservoir's oil.

2.1. Compositional model

The model assumes that there exists n_c hydrocarbon components and a water component. The n_c hydrocarbon component mass balances are

$$-\nabla\cdot\left(\rho_o x_i \vec{v}_o + \rho_g y_i \vec{v}_g\right) + q_i = \frac{\partial\left[\phi\left(\rho_o S_o x_i + \rho_g S_g y_i\right)\right]}{\partial t} \tag{1}$$

where subscript i is the index for mass components, $i = 1,\ldots,n_c$,; subscripts o and g are phase indices for the oil and gas phases; ρ is phase molar density; S is phase saturation; x is molar fraction in oil phase; y is molar fraction in gas phase; ϕ is the reservoir porosity; q is the sink/source per unit volume of reservoir.

The water mass balance is

$$-\nabla\cdot\left(\rho_w \vec{v}_w\right) + q_i = \frac{\partial(\phi\rho_w S_w)}{\partial t} \tag{2}$$

$\vec{v}_\beta$ is the Darcy velocity of phase β:

$$\vec{v}_\beta = -\frac{k k_{r\beta}\nabla P}{\mu_\beta} \tag{3}$$

where β is a phase index for the gas, oil or water phases; μ is viscosity; k is the reservoir permeability; $k_{r\beta}$ is the relative permeability of β phase; P is the reservoir pressure and the capillary pressure has been ignored in this model.

The mole fraction constraint of the oil phase is

$$\sum_{i=1}^{n_c} x_i = 1 \tag{4}$$

The mole fraction constraint of the gas phase is

$$\sum_{i=1}^{n_c} y_i = 1 \tag{5}$$

The saturation constraint is

$$S_o + S_g + S_w = 1 \tag{6}$$

2.2. Discretized governing equations

The finite volume method is employed for space discretization. Fig. 1 shows the space discretization and geometry data.

Fig. 1 shows the geometry of two neighboring control volumes, CV_n and CV_m, which are arbitrary, A_{nm} is the area of the interface between two control volumes, l_{nm} is the distance between the two control volume centroids, $\mathbf{n}_{nm}$ is the unit normal to the interface inside CV_n, $\mathbf{f}_{nm}$ is the unit vector along the direction of the line joining the two control volume centroids.

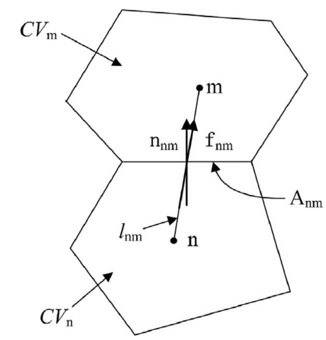

Fig. 1. Space discretization and geometry data in the finite volume method.

The discretized equations of hydrocarbon components and the water component can be obtained by volumetric integration and application of the divergence theorem for equations (1) and (2) over CV_n. To assure numerical stability the time is discretized fully implicitly.

For hydrocarbon component i,

$$\sum_{m\in\eta_n}\left[(\rho_o x_i\lambda_o)^{t+1}_{nm+\frac{1}{2}}\gamma^{t+1}_{nm}\left(P^{t+1}_m - P^{t+1}_n\right) + \left(\rho_g y_i\lambda_g\right)^{t+1}_{nm+\frac{1}{2}}\gamma^{t+1}_{nm}\left(P^{t+1}_m - P^{t+1}_n\right)\right] + (Vq_i)^{t+1}_n = \frac{\left[V\phi\left(\rho_o S_o x_i + \rho_g S_g y_i\right)\right]^{t+1}_n - \left[V\phi\left(\rho_o S_o x_i + \rho_g S_g y_i\right)\right]^t_n}{\Delta t} \tag{7}$$

For the water component,

$$\sum_{m\in\eta_n}\left[(\rho_w\lambda_w)^{t+1}_{nm+\frac{1}{2}}\gamma^{t+1}_{nm}\left(P^{t+1}_m - P^{t+1}_n\right)\right] + (Vq_w)^{t+1}_n = \frac{(V\phi\rho_w S_w)^{t+1}_n - (V\phi\rho_w S_w)^t_n}{\Delta t} \tag{8}$$

where subscript $nm + 1/2$ denotes a proper averaging at the interface between CV_n and CV_m; η_n donates all neighboring control volumes of n; λ is the phase mobility defined as $\lambda_\beta = k_{r\beta}/\mu_\beta$ for phase β; P is the pressure; $t + 1$ is the current time step; and t is the previous time step; γ is the transmissivity defined as

$$\gamma^{t+1}_{nm} = \left(\frac{A_{nm}\mathbf{n}_{nm}\cdot\mathbf{f}_{nm}}{l_{nm}}\sqrt{k_n k_m}\right)^{t+1} \tag{9}$$

2.3. Inner boundary model

During well testing, the sandface rate is unequal to the surface rate at the beginning as a result of wellbore storage. The inner boundary condition can be written as follows, considering the effect of wellbore storage: