Numerical Simulation of Three Phase Displacement Characteristics of Foam Fluid In Homogeneous Porous Media

Du D.X, Zhang D
1. College of Electromechanical Engineering, Qingdao University of Science and Technology, Qingdao 266061, China
2. Geo-Energy Research Institute, Qingdao University of Science and Technology, Qingdao 266109, China
E-mail: du-dongxing@163.com , Tel: 0532-88956166

Abstract: Foam technology has found wide applications in enhanced oil recovery and greenhouse geological storage. In this paper, a numerical simulate is carried out with the stochastic bubble population balance model on the foam three phase displacement process in a homogeneous oil/water/gas coexistence porous media of liquid. The effects of the maximum equilibrium bubble density n_{max} and the foam generation rate Kg on foam displacement process is mainly discussed. Numerical results indicate that the oil phase can be displaced well by foam fluid. Larger n_{max} values lead to higher apparent viscosity of foam and higher the pressure difference, and with the increase of Kg, the number of foam can reach a balance in a short distance, so it has better displacement effect on the oil phase components. The results obtained in this paper have a certain guiding role in understanding the enhanced oil recovery mechanism of foam fluid.
Keywords: porous media; foam fluid; three-phase displacement; numerical simulation

1. Introduction

In the process of oil exploitation, foam technology is widely used to enhance the industrial practice of oil recovery (EOR). The gas flooding usually leads to lower oil displacement efficiency due to the gravity segregation and the channeling of gas in high permeability strata, while foam technology can significantly increase the viscosity of the gas phase, control the displacement gas well and final improve the oil recovery [1-6].

In order to describe the seepage characteristics of foam liquid in homogeneous porous media successfully, we must conduct in-depth research on it. The displacement characteristics of foam in porous media can be analyzed, simulated and predicted simply and reliably by numerical methods. Some researchers use the assumption of single phase non Newtonian fluid to simulate the foam rheological properties [7-9], but the method is lack of generality and can not reflect well the percolation mechanism of foam in porous media and predict correctly displacement characteristics. In the rheological model based on two-phase fluid assumption, the number of bubbles n_f is a very important parameter. Among the current foam number models, the most famous are the phase-separation flow model and the bubble number conservation model. The phase separation flow model is proposed by Rossen [10-14], and the conservation model of the number of bubbles are proposed by Patzek and Kovscek etc. [15-18].Although based on the dynamic balance of bubble density, the conservation model is too difficult to apply in practice due to the excessive number of parameters in the model. Therefore, the more successful commercial software for multiphase flow modeling of reservoirs, such as Eclipse [19] and CMG's STARS [20], does not calculate the seepage flow rate by calculating the apparent viscosity of foam, but directly revises the flow of the foam phase.

Recently, Zitha and Du (2010) [21-22] developed a new conservative model for the number of random foams that moves in foams in porous media. The stochastic population balance model is based on the following basic assumptions:

(1)As a complex two phase fluid system, the rheological properties of foam are described by Herschel-Bulkley model.

(2)The foam rheology essentially depend on the foam density (number of bubbles per unit volume of porous media).

(3)The generation of foam could be treated as a stochastic process and the kinetics of foam generation obeys a simple exponential growth law.

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Compared with the traditional quantitative equilibrium model, the stochastic population balance model consists of two basic parameters (foam generation rate of Kg and maximum bubble number of n_∞), which are more easily determined through experiments.

In this paper, the numerical simulation of the displacement process of gas, water and oil three-phase in homogeneous porous media is carried out by using the black oil model [23-26] and the stochastic population balance model. In the numerical simulation process, the three phase displacement process of foam liquid in oil-water saturated porous media is mainly analyzed. At the same time, the numerical simulation results of foam displacement and gas displacement are compared.

2. Numerical simulation

2.1. Computational domain

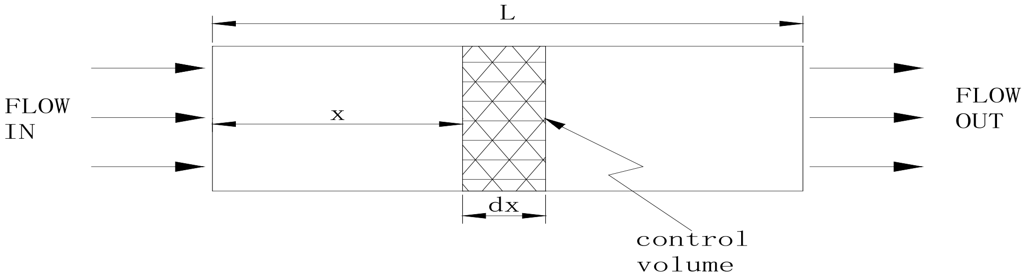


Fig.1. Computational domain

Fig.1. shows a homogeneous porous medium with a length of L, a porosity of Φ and a permeability of K in the calculation area of this paper. This simulation is the foam displacement process of three phases of gas, water and oil along the sand core in one dimensional case, with gas injection from the left side at a certain speed u to the right side. The length of the porous medium is L=0.2m. The initial condition of the calculation is 40% water, 50% oil, 10% gas in the porous medium with a system back pressure of 0.1MPa (atmospheric condition). Gas injection rate is 0.005m/s and the velocities of the aqueous and oil phases are both set to 0m/s. In the outlet, the pressure of the oil phase is set to be constant of 0.1MPa in the numerical simulation.

2.2 The governing equations with stochastic population balance model

Ignoring the gravity, the partial differential equation of the foam number conservation model [23] is:

$$\begin{cases} \phi \dfrac{\partial(\rho_i S_i)}{\partial t} + \nabla.(\rho_i \mathbf{u}_i) = 0 \\ \mathbf{u}_i = -\lambda_i \nabla P_i \\ \phi \dfrac{\partial(n S_f)}{\partial t} + \nabla.(n \mathbf{u}_f) = \phi S_f K_g (n_\infty - n) \end{cases} \tag{1}$$

Auxiliary equations are:

$$S_w + S_g + S_o = 1; \quad p_{cow} = p_o - p_w = f(S_w, S_g); \quad p_{cog} = p_g - p_o = f(S_w, S_g) \tag{2}$$

Where ρ_i, S_i, u_i, λ_i, P_i respectively refers to the i-phase fluid density, saturation, velocity, fluidity and total pressure, where $i \in \{w, f, o\}$(subscript f refers to the bubble). K_g and n_∞ are foam-related parameters that can be easily measured experimentally. In this simulation analysis, the aqueous phase is assumed to be incompressible and the foam conforms to the ideal gas law. n_∞ is approximately equal to the pore volume of foam and porous media at steady state, which is: $n_\infty \approx S_f \varphi / r^3$.

In the auxiliary equation, p_{cow}, p_{cog} refers to the capillary pressure between oil-water phases and oil-gas phases. Among them, the capillary pressure of oil-water and oil-gas are the function of liquid-phase saturation S_w and gas-phase saturation S_g, respectively. The capillary pressure is taken as 0 in this simulation for simplification, due to the capillary pressure is relatively small.

The mobility λ_i of the i-phase fluid is defined as:

$$\lambda_i = \frac{k_i}{\mu_i} = \frac{k k_{ri}}{\mu_i} \tag{3}$$

Where k_{ri} is relative permeability of the i-phase fluid, μ_i - the viscosity of the fluid, and

$$\mu_f = \mu_g + \alpha \frac{n}{u_f^c} \tag{4}$$

Where α and c are constants and n is the bubble density.

The relative permeability k_{ri} fluid expression is [9]:

$$k_{ro} = \left(\frac{S_o}{1-S_{wc}}\right)^{\lambda} ; \quad k_{rg} = \left(\frac{S_g}{1-S_{wc}}\right)^{\lambda} ; \quad k_{rw} = \left(\frac{S_w - S_{wc}}{1-S_{wc}}\right)^{\lambda} \tag{5}$$

Where S_{wc} refers to the residual water saturation, take 0.23; λ is a constant of 3.0.

The employed parameters are listed in Table 1.

Table 1 fluid and rock properties parameters

Parameter	Value	Parameter	Value
S_{wc}	0.23	$\mu_g\,(\mathrm{Pa\cdot s})$	18.1×10^{-6}
ϕ	0.23	α	8.6×10^{-7}
$K(\mathrm{m}^2)$	2.0×10^{-12}	λ	3.0
$\mu_w\,(\mathrm{Pa\cdot s})$	1004.0×10^{-6}	c	0.333333

Note: The parameters identified in Table 1 satisfy Bentheimer sandstone [27].

2.3 Method of numerical solution

In the numerical solution, we assume that: no gas dissolved in oil phase with R_s=0, the water and oil phase are incompressible with B_o=1, B_w=1.

We solve equation (1) ~ (2) using IMPES method, which divides the numerical procedure into three steps (superscript *n* on behalf of time):

(1)The oil phase pressure P_o^n at time *n* is implicitly calculated from the oil phase pressure P_o^{n-1} at the previous time, and the gas phase pressure P_f^n at the time *n* which can be obtained from the sum of P_o^n and P_{cog}^n, and the the water phase pressure P_w^n at time *n* can be found from the difference between P_o^n and P_{cow}^n, where P_{cog}^n, P_{cow}^n is known.

(2) The water phase saturation distribution S_w^{n+1} at time *n*+1 can be explicitly obtained from S_w^n and P_w^n.

(3) The oil phase saturation distribution S_o^{n+1} at time *n*+1 can be explicitly determined by S_o^n and P_o^n.

(4) The foam density distribution n^{n+1} at time *n*+1 can also be determined explicitly using known values - n^n , P_f^n , S_f^n , S_f^{n+1}

3. Results and analysis

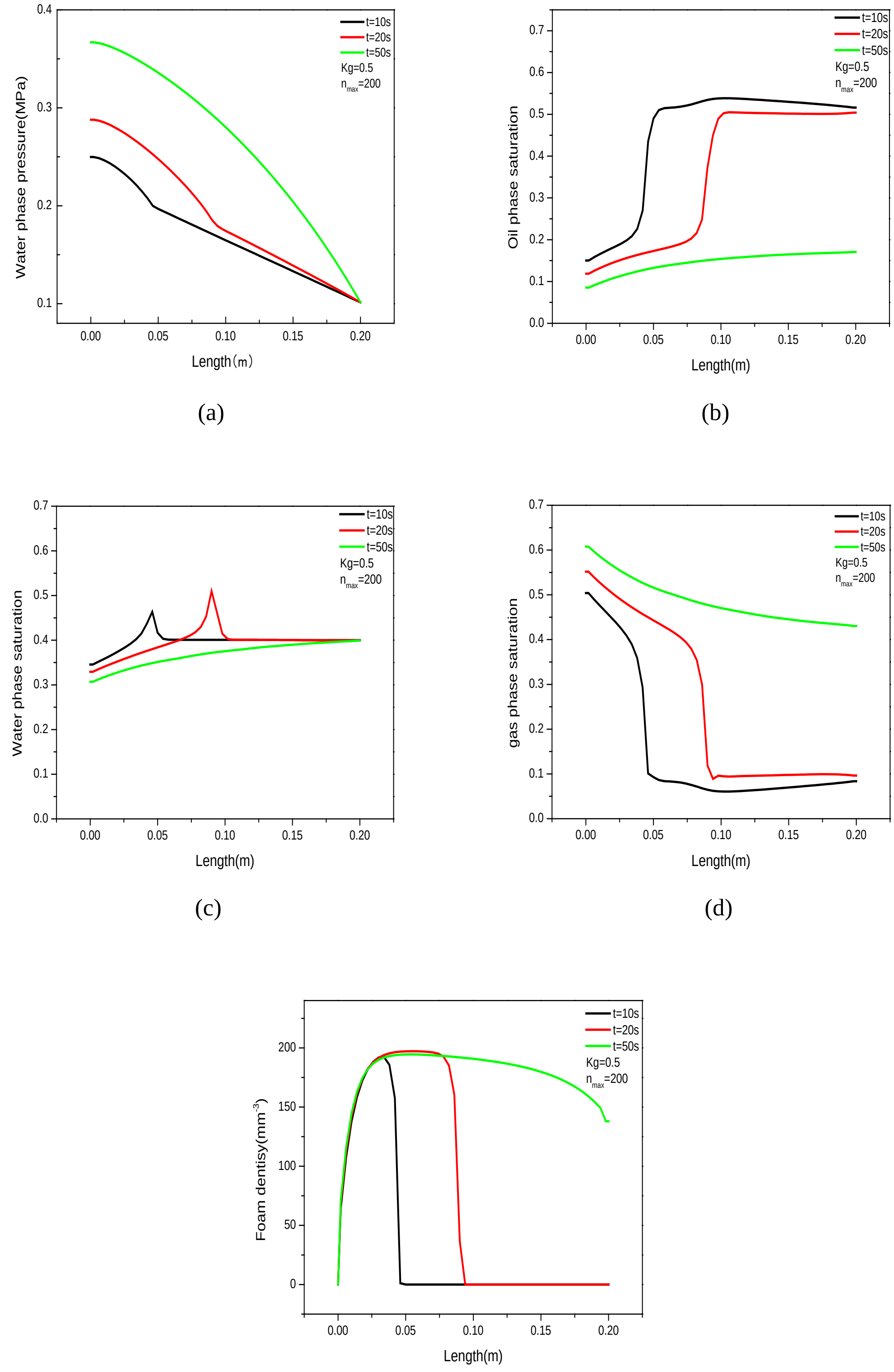
3.1 Foam three phase displacement process in homogeneous porous medium (*Kg*=0.5, n_{max}=200)

Fig.2. shows the typical curves of water phase pressure, oil/water/gas phase saturation and foam density parameters along the sample in the transient displacement times of 10s, 20s, 40s and 50s respectively. Numerical calculations are carried out under the condition of *Kg*=0.5 and n_{max}=200, and the typical foam three phase displacement behavior can be observed from the figure:

(1) The water phase pressure drop increases gradually along with the displacement process. At t=40s and 50s, the pressure difference is basically kept around 0.37MPa, indicating that the foam has completed the breakthroughs and achieved fully development at this time.

(2) At the designated relative permeability functions, the foam fluid mainly displaces the oil phase rather than water phase during the displacement process. After foam breakthrough, the foam (gas) saturation in the medium increases to 0.5-0.65, the oil saturation decreases to 0.1-0.2, which the water saturation is maintained around 0.4. The calculation results show that the injection of foam can efficiently displace the oil phase.

(3) Along with the displacement time, the foam density increases along with the change of oil, water and gas three phase saturation.



(a) (b) (c) (d) (e)

Fig.2 Different times of displacement (a) water phase pressure (b) oil phase saturation (c) water phase saturation (d) gas phase saturation (e) foam density along the course of change curve(Kg=0.5,n_{max}=200)

3.2 Foam three phase displacement process under different n_∞ values

Fig.3 (a) to (e) show the water phase pressure, oil/water/gas three phase saturation and foam density curve at displacement time of t=20s under different n_∞ values of 200, 500, 1000 respectively. The numerical simulation are carried out at constant *Kg*=0.5 to check the effect of n_∞ on foam three phase displacement behaviors. Following results can be obtained from the graphs:

(1) The pressure difference of the water phase pressure goes to maximum at n_{max}=1000, which reveals that the parameter n_{max} mainly affects the apparent viscosity of the foam. The larger the n_{max}, the larger the apparent viscosity of the foam fluid.

(2) With higher pressure drops at larger n_{max} values, the foam (gas) phase saturation increases, water phase and oil phase saturation decreases, showing an obvious effect of oil recovery enhancement effect.

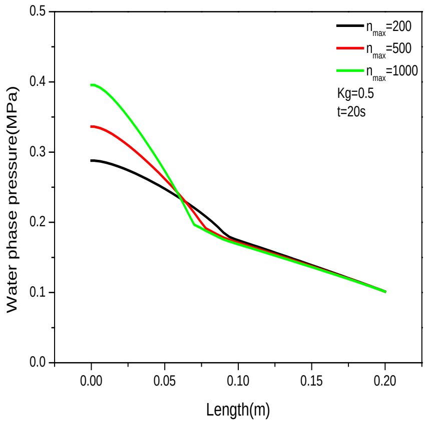
(3) The bubble density distribution, as shown in Fig.3 (e), doesn't vary too much under different n_{max} values.

3.3 Foam three phase displacement process under different *Kg* values

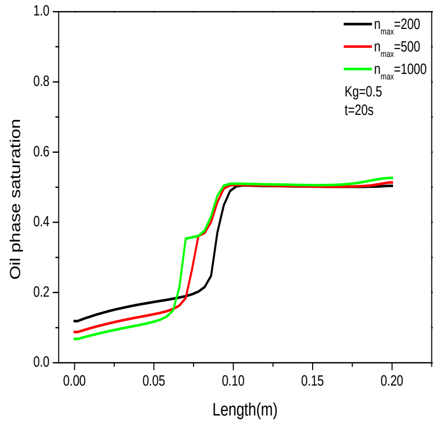
Fig. 4 (a)-(e) are the distributive curves of water pressure, oil/water/gas three phase saturation and foam density at displacement time of t=20s under various *Kg* values of 0.1, 0.5 and 1.0 respectively. The numerical simulation are carried out at constant n_{max}=200 to check the effect of *Kg* on foam three phase displacement behaviors. Following results can be obtained from the figures:

(1) Different *Kg* values have little effect on the water pressure difference in the displacement process under the same n_{max} values.

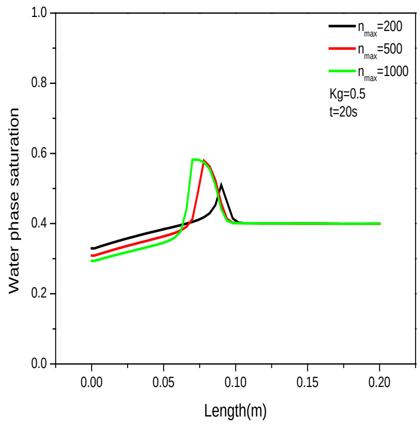
(2) The larger the *Kg*, the greater the foam generation rate, and the foam density can reach the equilibrium value in a relatively short time.



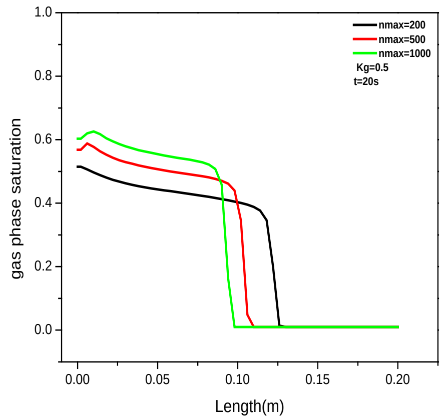
(a)



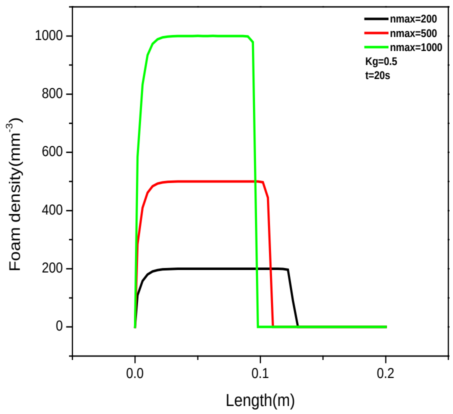
(b)



(c)

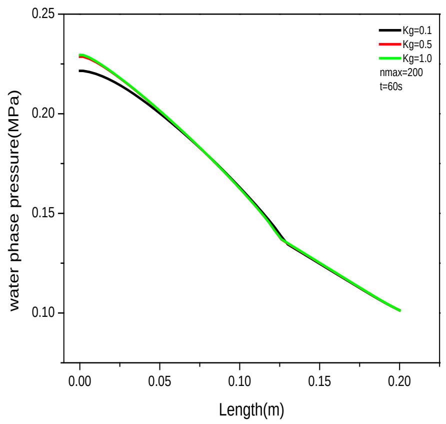


(d)

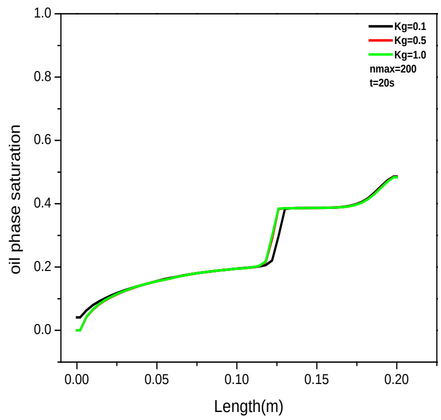


（e）

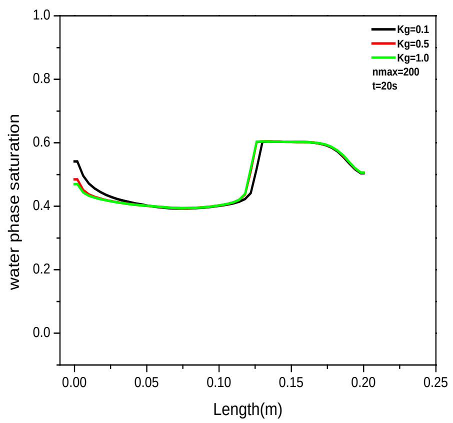
Fig.3. Foam three phase displacement process under different n_∞ values (n_{max}=200, 500, 1000),(a) water pressure (b) oil phase saturation (c) water saturation (d) gas phase saturation (e) foam density curves variation along the course



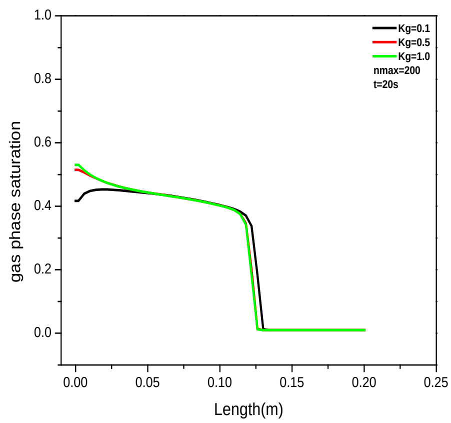
(a)



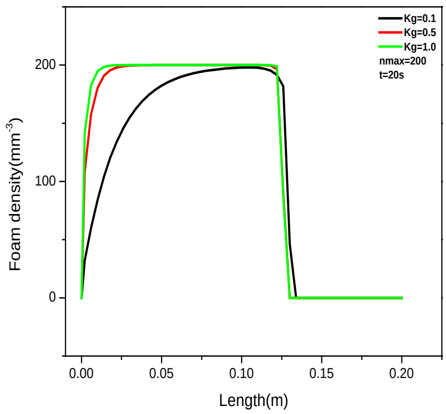
(b)



(c)



(d)



（e）

Fig.4. Foam three phase displacement process under different *Kg* values (*Kg*=0.1, 0.5, 1.0), (a) water phase pressure (b) oil phase saturation (c) water phase saturation (d) gas phase saturation (e) foam density curves variation along the course

4. Conclusions

In this paper, the stochastic population balance model was employed to simulate the foam three phase displacement behavior in homogeneous porous media. Following conclusions are obtained:

(1)Foam phase could produce extra oil component from oil/gas/water pre-saturated porous media due to its high apparent viscosity;

(2) Elevated maximum foam density n_{max} leads to higher pressure drop along the sample and therefore results in higher liquid phase recovery rate;

(3)Higher bubble generate rate *Kg* values could generate fully developed foam in a shorter distance after gas injection, however shows little effect on total liquid phase displacement efficiency of the foam flooding process.

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