Pore-scale model of two phase flow in 2D porous media: Influences of interfacial tension and heterogeneity effects on CO₂ injection in the tight oil reservoir

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Abstract. The CO₂ injection in tight reservoir is different from the conventional reservoir. For the porous media, the pore throat in the matrix reaches the level of nanopore, and the heterogeneity leads to huge difference during CO₂ injection. For the interaction of fluids, the reduction of interfacial tension caused by CO₂ is benefit to enhance oil recovery. To reveal the mechanism, pore scale model from tight formation is built and the influences of interfacial tension and heterogeneity are investigated. First, the migration of two-phase interface is studied by coupled with level set (LS) equation and Navier-Stokes (NS) equation. And finite element method (FEM) with interfacial adaptive mesh refinement is employed to solve the equation system. The results reach highly agreement compared with analytical solution and phase field method. Then, the pore throat distribution characteristics of porous media model are built by the scanning electron micrograph (SEM). Finally, based on the real porous media model from the SEM image, the influences of interfacial tension and heterogeneity are investigated. The pore scale model considering fluid and medium mechanism during CO₂ injection provides a better understanding of interfacial tension and heterogeneity effect in tight oil reservoirs.

1. Introduction

Tight oil reservoir plays an increasingly important role in energy resource and has a good development prospect, but the recovery rate is very low. The water flooding system is not fit to tight oil reservoirs because of the difficulty of injection, and CO₂ injection is advocated due to oil expansion and viscosity reduction caused by CO₂. The pore throats of tight oil reservoirs are micro and nano-sized, and the process of CO₂ injection in the micro matrix is different from that of conventional injection. Therefore, it is important to identify the seepage process of micro oil displacement. Many scholars have carried out corresponding researches, including experiment study and numerical simulation study.

Many scholars develop microscale experimental research. Du reveals the microscopic pore heterogeneity of tight oil sandstone reservoir in the experiment by considering both the resolution and representativeness [1]. Scanning Electronic Microscopy (SEM) and so on photomicrograph of thin section have been used to investigate the effect of microstructure on the variation of permeability in the tight carbonate reservoirs [2]. The influence of gas-wetting alteration, that means the alteration of interfacial tension, on the flow and distribution of fluids in porous media is studied with visualization flooding on a transparent glass micromodel whose original wettability is liquid-wetting [3].
Many scholars studies on interface migration by simulation. The traditional continuous medium model is suitable for seepage in the rock with wide range. And traditional simulation is based on the finite difference method and Darcy’s law. The interface of oil and gas does not exist in the grid because the simulation assumes that the reservoir fluid is continuous. The displacement and migration of the two-phase interface and its influence on the development effect cannot be accurately simulated. An enhanced VOF approach, which is to define the fluid volume fraction function C in the control body, couples with level-set and is applied to track the oil and the oil/air interface in the chamber [4]. Akhlaghi addresses simulation of non-isothermal water-oil displacements in porous media at pore-scale by coupling Cahn–Hilliard phase field and heat equations using COMSOL Multiphysics™ [5]. Jamaloei builds pore-scale porous media model to analysis the characteristics of imbibition under the high- and low-interfacial tension [6]. Jamaloei analyzes the mechanism of drainage process between the high- and low-interfacial tension [7]. Jamaloei investigates the characterization of low-interfacial tension flow and compares the effects of different pore geometries [8]. For shale formation, the effect of interfacial tension are explored during the process of water-oil mass transport in the pores [9]. However, few research has covered interfacial tension and heterogeneity effects during CO₂-oil displacements in porous media at pore- scale in the tight oil reservoir.

In this article, the research attempts to use finite element method combining with the level set equation and NS equations to simulate the displacement of micro-scale. And the new method is consistent with other methods including the analytical solution and phase field method. In this paper, porous medium model is constructed by SEM to simulate CO₂ injection process. And based on the proven model, the influence of the interfacial tension and heterogeneity effects on CO₂ injection in the tight oil reservoir are carried out. And it can be proved that the reduction of interfacial tension can improve the oil displacement efficiency in the tight oil reservoirs.

2. Method

2.1. N-S equation

The flow in porous media follows the conservation of mass [10-12], so the equation can be obtained:

\[ \rho \nabla (\vec{u}) = 0 \]  

(1)

The general form [11,12,13] of incompressible fluid considering the conservation of momentum and energy is:

\[ \rho \frac{\partial \vec{u}}{\partial t} + \rho (\vec{u} \cdot \nabla) \vec{u} = \nabla \left[ -pI + \mu (\nabla \vec{u} + (\nabla \vec{u})^T) \right] + \vec{F} \]  

(2)

Where \( \rho \), fluid density, kg/m³; \( \vec{u} \), fluid velocity, m/s; \( t \), flow time, s; \( \mu \), fluid viscosity, mPa.s; \( \vec{F} \), interfacial tension, N/m; \( p \), pressure, MPa; \( I \), unit matrix.

2.2. Level set equation

In the CO₂ injection process of Changqing tight oil reservoir, the formation pressure is lower than the miscible pressure, so there is an obvious oil-gas two-phase interface. In two-phase flow, an equation for interface migration is generated automatically from a level set interface. And a level set contour line, where \( \varphi \) is 0 in the level set equation, represents a two-phase fluid interface. And oil phase means \( \varphi \)=1 and gas means \( \varphi \)=0. Therefore, the level set equation of interfacial migration of two-phase fluid can be expressed as follows:

\[ \frac{\partial \varphi}{\partial t} + \vec{u} \nabla \varphi = \gamma \nabla \left( \epsilon_i \nabla \varphi - \varphi (1-\varphi) \frac{\nabla \varphi}{|\nabla \varphi|} \right), \quad \varphi=\text{phils} \]  

(3)

where \( \varphi \), the outline line of oil-gas two-phase interface; \( \gamma \), the reinitialization parameter of equation solution; \( \epsilon_i \), the interface thickness, m; \( \rho \), fluid density, kg/m³; \( \vec{u} \), fluid velocity, m/s; \( t \), flow time, s; \( \mu \), fluid viscosity, mPa.s.
2.3. Verification

2.3.1. Verification 1. To verify the accuracy of the method, 10μm×200μm model is established in Figure 1(a), and basic parameters of numerical simulation are shown in Table.1 according to the literature [12]. The parallel plate two-phase layered flow model is used for comparison. There are two immiscible fluids in the flow passage composed of two parallel infinite plates. And fluid 1 is in the blue region and fluid 2 is in the yellow region. Constant pressure gradient G1 and G2 are applied to fluid 1 and fluid 2 in the x direction respectively. COMSOL Multiphysics based on finite element is used to solve the coupling N-S and level set equation. If the fluid behavior between infinite parallel plates is stable and obeys poiseuille flow, then there is an analytical solution to the velocity distribution between two parallel plates on any section along the y direction [14]. The numerical and analytical solutions in the literature, such as Figure 1(b), are basically the same. Therefore, this method has good accuracy and can be used for the simulation of interface tracking process.

| Parameter                      | Value | Parameter                      | Value |
|--------------------------------|-------|--------------------------------|-------|
| Fluid 1 viscosity (mPa.s)      | 2     | pressure gradient G1 (Pa/m)   | 1*10^5 |
| Fluid 2 viscosity (mPa.s)      | 25    | pressure gradient G2 (Pa/m)   | 1*10^6 |
| Fluid 1 density (kg/m³)        | 1000  | a (μm)                        | 50    |
| Fluid 2 density (kg/m³)        | 1000  | b (μm)                        | 100   |

**Figure 1.** Validation of different methods (a) conceptual model (b) the comparison of different methods.

2.3.2. Verification 2. In order to verify the applicability of the model for different viscosity and density, we compared the parameters close to the actual gas injection case with the large viscosity difference. The interfacial tension of oil and gas leads liquid movement in Figure 2(a). When the viscosity ratio reached 200, the level set method compared the solution of Hagen-poiseuille for tube flow [15], as equation (4), and the result is shown in Figure 2(b). The result trend is basically consistent, which proves the validity of the method, but there is still room for improvement. When fluids have high viscosity ratio and different density, there is a certain gap between this method and the analytical solution.

\[ h = \sqrt{r \sigma \cos \theta / 2\mu} \]  \hspace{1cm} (4)

where \( h \) is the movement distance of liquid, mm; \( r \) is the radius of tube, mm; \( t \) is time, s; \( \sigma \) is the interfacial tension, mN/m; \( \theta \) is the contact angle; \( \mu \) is the viscosity of wetting phase (fluid 1), mPa·s.
Table 2. Basic parameters to verify differential viscosity.

| Parameter          | Value | Parameter          | Value |
|--------------------|-------|--------------------|-------|
| Fluid 1 (mPa.s)    | 2     | Fluid 1 (kg/m³)    | 800   |
| Fluid 2 (mPa.s)    | 0.01  | Fluid 2 (kg/m³)    | 300   |
| σ (mN/m)           | 16    | θ (°)              | 60    |
| h (mm)             | 5     | r (mm)             | 0.15  |

Figure 2. Validation compared with Hagen-Poiseuille with the different density and high viscosity ratio (a) the schematic diagram (modified from Cheng’s model [15]) (b) comparison with published literature [15].

3. Result and discussion

3.1. Case study
SEM is selected from literature [16] as shown in Figure 3(a), which includes white rock skeleton and black crude oil in tight sandstone. The obtained SEM is selected as a reasonable threshold for binaryzation to obtain the image shown in Figure 3(b), where the white part represents the rock skeleton and the black part represents the presence of crude oil in the pores. Based on the binaryzation image, the pore structure can be obtained and the real model can be constructed. Table 2 is the basic property of the model. The model is small and represents seepage characteristics, which satisfies the representative elementary volume (REV). Some scholars have carried out researches with similar methods that small rock slice is selected to simulate the flow behavior. And reasonable macroscopic properties are calculated by pore structures in the subvolumes of rock samples [17]. And influences of viscosity, capillarity, wettability and heterogeneity are investigated by similar pore-scale model of non-isothermal two phase flow in 2D porous media [5].

Table 3. Basic parameters of numerical simulation.

| Parameter                  | Value | Parameter                  | Value |
|----------------------------|-------|----------------------------|-------|
| Oil viscosity (mPa.s)      | 2     | Initial pressure (Pa)      | 0     |
| CO₂ viscosity (mPa.s)      | 0.01  | Injection velocity (m/s)   | 0.5   |
| Oil density (kg/m³)        | 800   | Outlet pressure (Pa)       | 0     |
| CO₂ density (kg/m³)        | 300   | Interfacial tension (N/m)  | 0.5   |
Figure 3. Real SEM in tight oil (a) real SEM (b) after binaryzation.

3.2. FEM with interfacial adaptive mesh

Finite element method is commonly used numerical calculation method to solve differential equations, as shown in section 2.2. And mesh generation is one of the important steps in numerical simulation. Conventional rectangular grids are easy to use, but for irregular boundaries in the tight pore throat as shown in Figure 3, a large amount of mesh generation is required, which greatly increases the number of nodes and the amount of calculation, and reduces the calculation efficiency. Therefore, the interfacial adaptive mesh is adopted for the complex pore structure [18]. This method can be used to divide grids flexibly at irregular sections as shown in Figure 4(a) and (b).

COMSOL Multiphysics™ is based on the FEM and adaptive mesh can be easy to implement. The real model is dissected by COMSOL Multiphysics™ grid subdivision mesh. And the global grid is shown in Figure 4(a) and local grid refinement details are in Figure 4(b).

Figure 4. Explanation of computational process (a) the global grid (b) the local grid refinement.

3.3. Sensitivity analysis

3.3.1. Heterogeneity. In order to study heterogeneity, a 2D homogeneous model with the same size 1050*1460 \( \mu \)m is established. Constant velocity is used for 0.5m/s for displacement at the entrance, and outlet pressure is set to 0pa [12]. Basic parameters are shown in Table.3. It can be seen that the pressure is evenly distributed in the homogeneous model. However, in order to maintain the same displacement velocity, a large red area exists in the real model due to heterogeneity in Figure 5. The red region represents high pressure that means the tight matrix is difficult to inject and requires greater displacement pressure than conventional reservoirs. Compared the velocities of different models in figure 6, conventional reservoir model has uniform velocities, but gas channellings easily happens for tight reservoir model due to the influence of heterogeneity as shown in the red area in Figure 6(b). Therefore, it is necessary to pay attention to the impact of gas channelling caused by heterogeneity in the tight reservoir.
3.3.2 Interfacial tension. Reducing the interfacial tension of oil and gas is the fundamental mechanism of CO$_2$ displacing oil. Interfacial tension is set to 0.5, 5, 10, 50 N/m respectively. Velocity distribution results are shown in Figure 7. And interfacial tension of Figure 7(a)(b)(c)(d) are 0.5, 5, 10, 50 N/m respectively. Among them, the blue region has a very low velocity, which is regarded as the region that cannot be displaced, and the other region is regarded as the effective affected region. It can be seen that, the sweep region is large in Figure 7 (a) with low interfacial tension (0.5 N/m) and the sweep region is small in Figure 7 (b)(c)(d) with high interfacial tension. In order to compare the sweep region more obviously, the low speed area, which is difficult to move, is hidden and the other region, which can be displaced, is remained in Figure 8. And the sweep efficiency of small pores, which is marked by the red circle in the same position of the model, is compared. When the interfacial tension is greater than 5 N/m in Figure 8(b)(c)(d), the oil displacement efficiency is not obviously improved. But when it reaches 0.5 N/m, smaller pore throats in the red circle are displaced, which improves the oil displacement efficiency. Therefore, low interfacial tension, caused by CO$_2$ displacing the oil, can improve the oil displacement efficiency in the tight oil reservoirs such as Figure 8(a).
Conclusions

The coupling equations of NS equation, considering the conservation of mass and energy, and the level set equation are established to simulate the two-phase fluid flow in porous media to more accurately analyze the microscopic seepage mechanism. The model is established according to the real core, and influences of interfacial tension and heterogeneity effects are investigated during CO$_2$ injection in the tight oil reservoir.

1. Real pore model in the tight oil formation requires higher displacement pressures than the conventional formation due to heterogeneity and it is necessary to pay attention to the impact of gas channelling caused by heterogeneity in the tight reservoir.
2. By comparing the displacement process of pore model with different interfacial tension, low interfacial tension can improve the oil displacement efficiency in the tight oil reservoirs.

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