A Novel Oil-Water Two-Phase Flow Numerical Simulation Method In Tight Sandstone Reservoirs

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Abstract. As a crucial factor affecting water flooding in tight sandstone reservoirs, dynamic capillary pressure (DCP) has significant impact on the production performance during oil-water flow. In this work, a novel numerical simulation method with DCP is developed to study oil displacement in tight sandstone reservoirs. Based on this new model, the impacts from DCP to water/oil displacement (or water flooding effects) are analysed. The results of this work show that the effects brought by dynamic capillary pressure cannot be neglected. The more significant dynamic effects of capillary pressure correspond to the sample with lower permeability. The effect of DCP is probably a major contributor to non-linear flow (non-Darcy flow) in tight sandstone reservoirs during water flooding process. Compared with the conventional flow theory (e.g., static capillary pressure theory), our derived model with DCP can help to reduce the uncertainty in water/oil flow in tight sandstone reservoirs.

1. Introduction

As stated in the literature, flow in tight reservoirs always involves multiphase fluids (e.g., oil-water system, gas-water system, oil-gas system, or oil-gas-water system) [1-2]. Physically, for tight reservoirs with multiphase system, capillarity is vital to determine the distribution of each phase (oil, water, or gas) in the porous media, and to the overall behavior of multiphase system prediction and characterization [3-4]. In general, based on experimental data (capillary pressure and saturation) of samples and regression analysis, capillary pressure-saturation empirical equations are used to characterize capillary pressure (CP) [5, 6]. In view of the definition of CP $p_c$ in macroscopic scale, we have [5-7]

$$p_c = p_{nw} - p_w = f(S_w)$$

(1)

where $p_{nw}$ and $p_w$ denote the mean pressures of the non-wetting fluid (e.g., oil phase in this study) and wetting fluid (e.g., water phase in this study), respectively. In addition, $S_w$ in Eq. (1) represents wetting fluid saturation. Note that Eq. (1) is proposed based on the assumption that fluid saturation changes slowly over time and each fluid distribution in samples is equilibrium. Consequently, Eq. (1) can’t be applied to describe CP in multiphase system with faster processes. Physically, during water/oil displacement, the relaxation time of fluid (oil or water) reaching capillary equilibrium state is slower than the distribution time of fluid in porous media. Thus, many scholars suggested CP relationships depend on flow conditions in multiphase system, and the significant dynamic effects should be taken into consideration [3, 8, 9].
As stated in the literatures, two main theories (the Barenblatt model and the Hassanizadeh-Gray model) have been proposed for incorporating dynamic effects in constitutive relations [10-17]. For the Barenblatt model, scholars introduced a concept of “time rate of saturation change” to describe the dynamic effects in CP [10, 11]. However, for the Hassanizadeh-Gray model, dynamic capillary coefficient \( \tau \) is related to porous material properties [12-19]. Under the non-equilibrium condition Eq. (2), besides the fluid saturation, DCP is also affected by the change rate of fluid saturation. Generally speaking, dynamic coefficient \( \tau \) varies with different core samples. Hassanizadeh et al. [14, 15] suggested that \( \tau \) varied from \( 3 \times 10^4 \) to \( 10^7 \) kg m\(^{-1}\)s\(^{-1}\). Gielen et al. [20] found that parameter \( \tau \) increased as the network size increased. For the greatest network size in their studies, they suggested that the maximum value of parameter \( \tau \) was \( 1.2 \times 10^5 \) kg m\(^{-1}\)s\(^{-1}\). However, Dahle et al. [18, 21] obtained small values of the dynamic coefficients which ranged between \( 1 \times 10^2 \) to \( 5.7 \times 10^7 \) kg m\(^{-1}\)s\(^{-1}\).

In this work, a novel simulation method with DCP will be developed. Based on this model, the impact from DCP to the water/oil displacement will be analyzed.

### 2. Theoretical study

For oil-water flow in tight sandstone samples, we assume that the flow is one-dimensional (1D) unsteady flow, then we have

\[
\frac{\partial}{\partial x} \left( \frac{K_o}{B_o \mu_o} \frac{\partial p_o}{\partial x} \right) + q_o = \frac{\partial}{\partial t} \left( \frac{\varphi S_o}{B_o} \right) \tag{3}
\]

and

\[
\frac{\partial}{\partial x} \left( \frac{K_w}{B_w \mu_w} \frac{\partial p_w}{\partial x} \right) + q_w = \frac{\partial}{\partial t} \left( \frac{\varphi S_w}{B_w} \right) \tag{4}
\]

where \( K \) denotes effective permeability, \( B \) denotes formation volume factor, \( \mu \) denotes fluid viscosity, \( p \) denotes fluid pressure, \( q \) denotes the source or sink strength of fluid, \( S \) denotes fluid saturation, \( \varphi \) denotes porosity, \( x \) denotes the distance and \( t \) is the displacing time. Moreover, subscript \( w \) denotes water phase, and \( o \) represents oil phase.

The capillary pressure equation can be described as [3, 12-17]

\[
p_c = p_o - p_w = p_{c,\text{stat}} - \tau \frac{\partial S_w}{\partial t} \tag{5}
\]

where \( p_c \) is capillary pressure, superscript \( \text{stat} \) denotes static, and \( \tau \) is dynamic capillary coefficient.

By combining Eqs. (4), (5) and the boundary conditions (e.g., inner boundary conditions and outer boundary conditions), the derived model can be solved with IMPES numerical method. Then, with the determined fluid pressure and fluid saturation at any produce time, oil/water displacement effect can be derived at different time using the iteration algorithm.

### 3. Results and Discussions

For numerical simulation purpose, we choose the basic parameters from a tight sandstone core sample (shown in Table 1) for the 1D water flooding model. The comparisons of \( S_w \) distribution and \( p_c \) distribution from core inlet face to core outlet face that are simulated between the case of taking SCP into account and the case considering the DCP are plotted in Figure 1 and Figure 2. Results (Figure 1) suggest that water saturation \( S_w \) is lower in the case of taking DCP into account than that in the case of taking SCP into account. Physically, during water flooding process, under a same water saturation \( S_w \),
DCP is larger than SCP [3, 12-17], leading to a greater flow resistance. As illustrated in Figure 2, under the same circumstance, the DCP is greater that the SCP at the same displacing distance, which is anticipated.

As plotted in Figure 3, the flow rate in the case of taking SCP into account and that in the case of considering the DCP are compared. Figure 3 shows that, for the case taking DCP into account, the flow rate is smaller than that in the case of taking SCP into account. Compared with the case taking SCP into account, the flow resistance in the case of considering DCP is greater. As a result, the flow rate in the case of considering DCP is smaller. In Figure 4, the flow rate versus pressure gradient is plotted. Figure 4 demonstrates each curve (flow rate versus pressure gradient) does not passes through the origin point (0, 0). It means that threshold pressure gradient (TPG) exists in the multiphase flow in tight cores. Figure 4 also shows that a larger value of TPG corresponds to a lower value of permeability. Results (Figure 4) reveals that the predicted flow rate is in agreement with the experimental data, which validates our new model. Consequently, the effect of DCP is probably a major contributor to non-linear flow (non-Darcy flow) in tight sandstone reservoirs during water flooding process [4]. More details about the experiments will be stated in our another paper.

### Table 1. Core sample parameters used in our simulation.

| Parameters                          | Values   | Parameters                          | Values   |
|-------------------------------------|----------|-------------------------------------|----------|
| Core diameter [m]                   | 0.025    | Oil viscosity [mPa·s]               | 1.387    |
| Permeability [10⁻³ μm²]             | 0.10     | Water viscosity [mPa·s]             | 1.002    |
| Compressibility coefficient [MPa⁻¹] | 0.005    | Original pressure [MPa]             | 0.1      |
| Immobile Water saturation [%]       | 40.0     | Residual oil saturation [%]         | 36.0     |
| Injection rate [ml/min]             | 0.05     | Core end pressure [MPa]             | 0.1      |
| Water FVF [m³/m³]                   | 1.0      | Oil FVF [m³/m³]                     | 1.2      |
| Core porosity [%]                   | 10.0     | Core length [m]                     | 0.16     |

**Figure 1.** Water saturation versus the displacing distance.

**Figure 2.** Capillary pressure versus the displacing distance.

**Figure 3.** Flow rate versus displacing time.

**Figure 4.** Predicted flow rate and test data.
4. Conclusions

In this work, dynamic capillary pressure (DCP) and its effect in water flooding in tight sandstone reservoirs are studied by numerical model. In general, in multiphase system, dynamic effects of capillary pressure in tight reservoirs with lower permeability are larger. Moreover, there exists a negative relationship between threshold pressure gradient and permeability. The effect of DCP is probably a major contributor to non-linear flow in tight sandstone reservoirs during water flooding process. DCP is a key unfavorable factor for development of tight sandstone reservoirs.

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