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Invited review

# A critical review on fundamental mechanisms of spontaneous imbibition and the impact of boundary condition, fluid viscosity and wettability

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**Abstract:** Spontaneous imbibition (SI) is one of the primary mechanisms of oil production from matrix system in fractured reservoirs. The main driving force for SI is capillary pressure. Researches relating to SI are moving fast. In the past few years, amount of literature on the development of SI with respect to many variables, such as mechanism of imbibition, scaling of imbibition data and wettability of matrix blocks. In this review, we first introduced the fundamental physics mechanism of SI through capillary tube models and micromodels. Then both conventional and more novel experimental methods of measuring oil production are discussed thoughtfully. This is followed by reviewing the oil production performance under various boundary conditions and the characteristic length in scaling equations that have been used to account for different cores shape and boundary conditions. The effect of fluid viscosity on the rate of oil production and final oil recovery as well as the development of viscosity term in the scaling equation are reported. The commonly used methods to quantitatively evaluate the wettability of cores and the SI under mix- and oil-wet conditions are introduced. And last but not least, the methods and mechanism of wettability alteration for enhanced oil recovery in mix- or oil-wet fractured reservoirs are presented.

**Keywords:** Spontaneous imbibition, fractured reservoirs, boundary condition, viscosity ratio, wettability.

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## 1. Introduction

Fractured reservoirs account for an important proportion of worlds hydrocarbon reserves and consist of two different systems: fracture system and matrix system (Behbahani et al., 2006; Chen and Mohanty, 2013; Mirzaei-Paiaman and Masihi, 2013; Chen and Mohanty, 2015). In fractured reservoirs, the matrix system, which has low permeability, is generally surrounded by fracture system, which has high conductivity. The oil in the fracture system is preferentially recovered by water injection or aquifer drive due to the high conductivity. For matrix system, the primary recovery mechanism is the spontaneous imbibition (SI), which is driven by capillary pressure. The essence of SI is the decrease of interfacial energy, which is through the action of capillary pressure. For the occurrence of SI, the water-rock interfacial energy must be lower than the oil-rock interfacial energy, which embodied that the rock must be water-wet. According to the flow direction of wetting and non-wetting phase, SI generally is divided into two types: co-current imbibition and counter-current imbibition (Pooladi-Darvish and Firoozabadi, 2000; Karpyn et al., 2009; Cai et al., 2010; Mirzaei-Paiaman et al., 2011). For co-current imbibition, the wetting and non-wetting phase flow through the same end face in opposite directions. For counter-current imbibition, the wetting and non-wetting phase flow through the different face in the same direction.

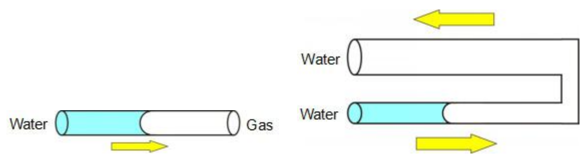
In the past few decades, many research groups made great contributions to the development of the topic of SI. Morrow and Mason (2001) make a review of SI and mainly focused on the scaling of experimental imbibition data. Recently, Mason and Morrow (2013) presented a review of SI experiments under very strongly water-wet conditions. The development of the investigation of SI is moving fast. In order to study the basic physics of SI, the idealized interacting tubes model was developed (Dong et al., 1998; Ruth and Bartley, 2002; Dong et al., 2005; Dong et al., 2006; Ruth and Bartley, 2011). Unsal et al. (2007a, 2007b, 2009) studied the SI in the tube model experimentally by designing specific experimental setup consisting of two non-axisymmetric tubes. The micromodels were used to visualize the fluid flow patterns at the pore scale during the course of SI (Rangel-German and Kovscek, 2006a; Hatiboglu and Babadagli, 2008). The method that used to study the SI in porous media is an important issue. The imbibition cell method and weighing method are the most commonly used methods to measure oil production by SI. Some advanced imaged techniques, including X-ray CT scanning (Akin et al., 2000; Zhou et al., 2002) and Magnetic resonance imaging (MRI) method (Baldwin and Spinler, 2002; Fernø et al., 2013), were applied to detect the fluid distribution in cores. Various boundary conditions were applied in imbibition experiments according to the boundary condition of matrix blocks in fractured reservoirs (Bourblaux, 1990; Standnes, 2004). Fluid viscosity is a significant parameter in the rate of oil production and final oil recovery from fractured reservoirs. The viscosity term in scaling equation, which is used to compensate for the variation of fluid viscosities, has been developed and modified by many research groups. The correlation between viscosity ratio and relative permeability is still a confusing problem. Since most carbonate reservoirs are mix- or oil-wet, amount of literature focused on the SI under mixed- and oil-wet condition (Austad et al., 1998; Gupta and Mohanty, 2010). The rate of oil production by SI in oil-wet cores is very slow or nonexistent. The methods of wettability alteration have been growing interest for enhanced oil recovery from oil-wet fractured reservoirs (Austad and Milter, 1997; Hirasaki and Zhang, 2004).

In this paper, the tube models and micromodels are used to illustrate the basic physics mechanism of SI. The various methods to study SI in porous media at pore scale are introduced. The SI in cores with different size and shape under different boundary conditions are reviewed and the characteristic length in the scaling equation used to compensate for the different core shapes and boundary conditions is discussed. The effect of fluid viscosity on the rate of oil production by imbibition and the viscosity term in scaling equation is introduced. The effect of fluid viscosity on the final oil recovery and relative permeability is analyzed as well. The effect of wettability on SI is reported and the methods of wettability alteration for enhanced oil recovery from mix- or oil-wet fractured reservoirs are introduced.

## 2. Microscopic mechanism of spontaneous imbibition

### *2.1 Fundamental physics mechanism of spontaneous imbibition*

The SI experiments were firstly conducted by Washburn (1921) using a single capillary tube. During the experiments, one end of the tube was connected to water and the other end was connected to air. The water was draw into the tube due to capillary pressure and air in tube was expelled accordingly. Generally, this is called co-current imbibition (Fig. 1). During co-current imbibition, the outlet of tube was in contact with non-wetting phase; therefore, there is no capillary back pressure. Washburn also reported that the distance advanced by water-air interface were linear to the $\sqrt{\text{time}}$ when the viscosity of non-wetting phase is negligible. For the tube with constant diameter, if both ends of the tube were connected to water, the water-gas meniscus would form in both ends of the tube and capillary pressure would exist in both ends of tube as well. Therefore, water would be draw into the tube from two ends. When the pressure in the gas was equal to the capillary pressure, the water could not continue to be draw into the tube. However, if the diameter of the tube was not constant, the capillary pressure in tube was not equal either (Fig. 1(b)). The capillary pressure in the large tube would be smaller than that in the small tube. When the pressure in gas was larger than that in the large tube, the gas would be expelled from the large tube. Under this condition, the direction of water imbibition and the direction of gas expelling were opposite. Therefore, it is generally called counter-current imbibition. It is noticed that the main difference between co- and counter-current imbibition is whether the expelling of non-wetting phase needs to overcome the relative smaller capillary




(a) Co-current imbibition (b) Counter-current imbibition

**Fig. 1.** Schematic illustration of co- and counter-current imbibition.

pressure, which is generally called capillary back pressure.

In porous media, the topology of pore structure is complex and fluid flows between the various pores interfere with each other. In order to simulate the interaction of fluids flowing between adjacent pores, Dong et al. (1998) introduced an idealized interacting capillary model (Fig. 2). In their model, it was assumed that the pressure at any fixed location in different capillaries were equal in the single phase zone, i.e., there was no fluids convection between the two capillaries in the single phase zone. The two tubes were saturated with oil and the left end was connected to water and the right end was connected to oil (at the same pressure). The water was initially drawn into the smaller tube (tube 2). Since the capillary pressure in the larger tube was smaller than in the smaller tube, the oil was pushed out from the left end of the larger tube. Also since the pressure at the right end of the tube was lower than the pressure at the imbibition front in the smaller tube, the oil was pushed out from the right end of the tube. As the water-oil meniscus advanced along the smaller tube, the oil pressure at the water-oil meniscus decreased. When the oil pressure at the water-oil meniscus was lower than the capillary pressure in the larger tube, the water began to imbibe into the larger tube. The advancing velocity of water-oil meniscus in tube 2 could be obtained as follows:

$$v_2 = \frac{q_2}{\pi r_2^2} \tag{1}$$

where $v_2$ is the advancing velocity of the water-oil meniscus in tube 2; $q_2$ is the water flow rate in the tube 2. Similarly, the advancing velocity of water-oil meniscus in tube 1 could be obtained as follows:

$$v_1 = \frac{q_t}{\pi r_1^2} \frac{r_1^4}{r_1^4 + r_2^4} \tag{2}$$

where $v_1$ is of advancing velocity of the water-oil meniscus in tube 1; $q_t$ is the total flow rate. Dong et al. (2005, 2006) extended the interacting capillary model to interacting capillary bundle model and the mathematical model was solved by numerical methods for analyzing patterns of fluid flow in porous media. The numerical calculation results are in agreement with experimental results reported in literature.

In the idealized interacting capillary model, it was assumed that there was no fluids convection between the capillaries in single phase zone. Wang et al. (2008) reported that this assumption may be incorrect. According to the Hagen-Poiseuille equation, the velocity of water in the larger tubes would be greater than the velocity in the smaller tube. However, in the idealized interacting capillary model, the average advancing velocity of water-oil meniscus in the smaller tube was faster than in the larger tube. This is physically impossible without fluids convection between the tubes in the single phase zone. Accordingly, Wang et al. (2008) developed an improved interacting capillary model with hypothesis that there was fluid convection between the capillaries over the total single phase zone by a uniform resistance. The numerical calculations showed that the predictions of the modified model were very close to the predictions of the idealized capillaries model. The differences between the two models could be negligible. Therefore, in order to simplify the calculation, the idealized model could be used to predict the fluid flow in porous media for practical purposes.

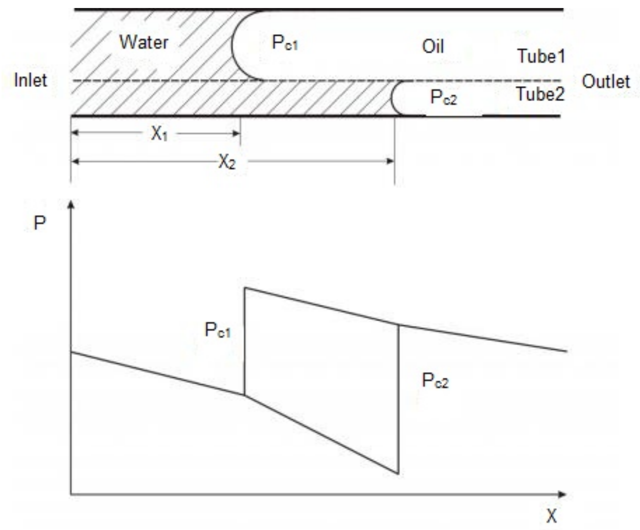



**Fig. 2.** Schematic illustration of tubes model and pressure profiles in the model (Dong et al., 1998).

## 2.2 Experimental study of capillary models

Unsal et al. (2007a, 2007b, 2009) introduced experiments to illustrate the basics of imbibition in tubes by using a non-axisymmetric geometry tube model pore systems. The tube model pore systems consist of a rod in an angled round-bottomed slot covered by a transparent glass plate. The tubes could be made up by the surfaces of the slot, rod and the glass plate. The independent capillaries and the interconnected capillaries could be achieved by adjusting the depth of the rod (Fig. 3). The tubes connected each other at both ends. One end of the tube model was open to refined oil and the other end was open to air for co-current imbibition or sealed and connected to pressure transducer for counter-current imbibition.

Imbibition experiments were first conducted by use of independent capillaries (Unsal et al., 2007a). In co-current imbibition, the meniscus in the larger tubes advanced faster than that in the smaller tubes, which was agreement with the prediction of Hagen-Poiseuille equation. The experimental results also showed that the distance advanced by each meniscus was linear to the $\sqrt{\text{time}}$ even though the advancing velocity of meniscus in each tube varies with time. It implies that the capillary pressures in the tubes are constant, i.e., the capillary

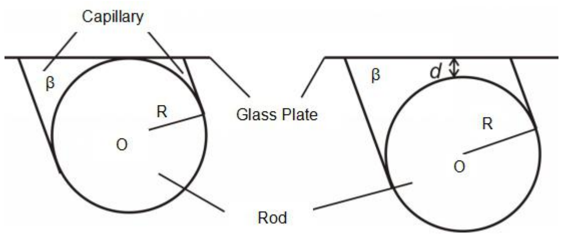



**Fig. 3.** Structure of the capillaries, (a) the rod is in contact with the glass plate, two independent capillaries, (b) there is a gap between the rod and the glass plate, the capillaries are interconnected (Unsal et al., 2007b).

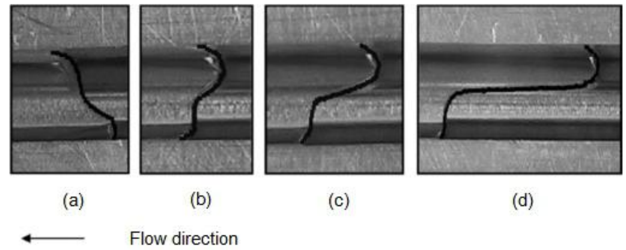



**Fig. 4.** Single frames taken at different times for co-current imbibition by use of interconnected capillaries (Unsal et al., 2007b).

pressure is independent of the rate of SI. Accordingly, in porous media, the capillary pressure can be also independent of rate of SI, i.e., the capillary pressure is a single function of saturation. In counter-current imbibition, the menisci initially advance in both tubes and the meniscus in the larger tube advances faster than that in the smaller one. As the pressure in air increases, the wetting phase in the larger tube is pushed back until the gas is expelled as bubbles through the larger tube. Generally, when the capillary back pressure is constant, the distance advanced by the smaller meniscus would be linear to $\sqrt{\text{time}}$. However, the experimental results showed that the imbibition rate increases when the bubble starts to form. After the bubble snap off, the linear relationship between the advanced distance of meniscus and the square root of imbibition time is regained again. It implied that the capillary back pressure could not be constant for SI in porous media.

Later, Unsal et al. (2007b) reported experimental results of co- and counter-current imbibition by use of interconnected capillaries. The experimental behavior with interconnected capillaries is different to that with independent capillaries. In co-current imbibition, the meniscus in the smaller tubes advances faster than that in the larger tubes, which is agreement with the prediction of idealized interacting model proposed by Dong et al. (1998) (Fig. 4). In counter-current imbibition, similar to the independent capillaries, initially both menisci advance and the larger one advances faster. As the air in the tube is compressed, the meniscus in the larger tube is pushed back. Ultimately a bubble is expelled from the larger tube. For counter-current imbibition, Unsal et al. (2009) studied the bubble snap-off and capillary back pressure in the larger tube in detail as well. It can be seen that the bubble snap-off is the result of capillary instability. The experimental results showed that once the bubble started to generate, the dead end pressure decreased dramatically. After the bubble snapped off, the dead end pressure rose to approximately the initial value.

## 2.3 Micromodels for spontaneous imbibition

The simple tube model makes important contribution to understanding the basic physics of SI. However, since the pore structure of porous media is complex, some research groups attempted to visualize fluid movement for SI at the pore scale throughout the two-dimensional micromodels. Rangel-German and Kovscek (2006b) illustrated experiments involving water imbibition into a matrix and matrix-fracture interactions between wetting and non-wetting phase by use of the micromodels. The etched-silicon-wafer micromodels, which offer 1:1 size scaling of typical sandstone, were used to simulate the matrix and fracture system (Fig. 5). Two types of experiments, which were called “filling-fracture”and “instantly filled fracture”experiments, were conducted.

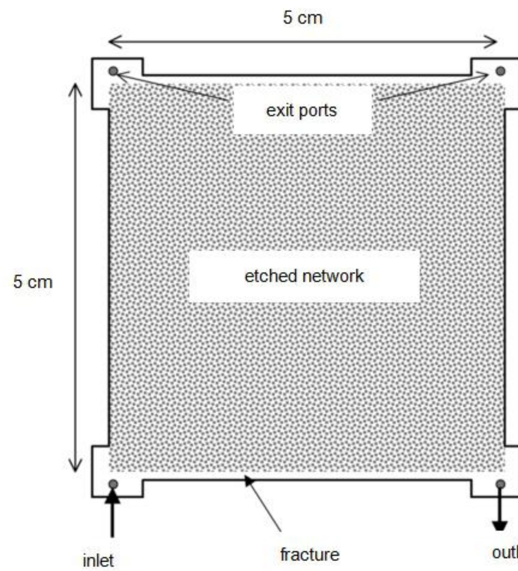



**Fig. 5.** Schematic of the micromodel including the matrix and fracture system (Rangel-German and Kovscek, 2006b).

The filling-fracture and instantly filled fracture regimes, which were determined by whether the fracture filled with water before substantial water imbibed into the matrix system, were achieved by use of low and high injection rates through the fracture. In filling-fracture experiments, a large amount of water has imbibed into the matrix and air is ejected co-currently relative to water before the fracture is filled with water. In addition, little snap-off of air were observed. For snap-off to occur pore corners and crevices must fill with water and sufficient liquid for snap-off must accumulate at the pore throats before the pore is filled completely by the advancing imbibition front (Akin et al., 2000; Kovscek, 2003). For water-gas system, it was observed that the advancing front filled pores with water at least as rapidly as pore corners swelled with water. Therefore, the snap-off of air was suppressed by the rapid SI of water. Akin et al. (2000) reported the similar experimental results using X-ray imaging

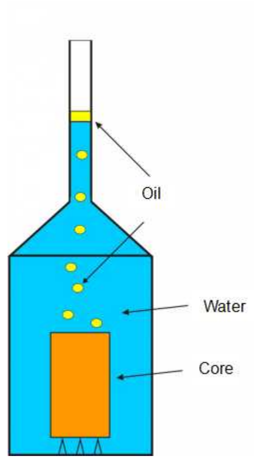



**Fig. 6.** Imbibition cells used to measure oil production by SI.

to study the SI in diatomite samples. In instantly filled fracture experiments, little water was drawn into the matrix system before the fracture was filled with water and non-wetting phase was ejected from the matrix system counter-currently. It was observed that the water imbibed into the smaller pores and the air was ejected from the larger pores. The production flow paths of air were smaller in dimension, which is agreement with experimental results of high water saturation behind the imbibition front by use of diatomite samples (Akin et al., 2000). Hatiboglu and Babadagli (2008, 2010) conducted the similar visualization experiments by use of two-dimensional sandpacks and micromodels to clarify the physics of SI at pore scale. The processes of co- and counter-current imbibition were modeled using lattice Boltzmann method (LBM) as well. It was validated that LBM captured the physical mechanism at pore scale for both co- and counter-current imbibition transfer processes between matrix and fracture. They also reported that the pore size and matrix geometry have an important effect on the residual oil saturation. Recently, Cai et al. (2014) developed a more generalized SI model is by considering the dierent sizes and shapes of pores, the tortuosity of imbibition streamlines in porous media, and the initial wetting-phase saturation. The interrelationships of accumulated imbibition weight, imbibition rate and gas recovery and the properties of the porous media, wetting liquids, and their interactions are also derived analytically.

## 3. Experimental method of spontaneous imbibition in porous media

### *3.1 Imbibition cells and weighing methods*

Experiments of SI in porous media are the most important method to quantify oil production by SI and predict the rate of oil recovery from fractured reservoirs. Over the past few decades, many experimental methods and setups as well as advanced techniques were presented to study various items of SI.

The most commonly used experimental setup to test oil production by the SI is imbibition cells (Fig. 6). The core samples saturated with oil are put into the imbibition cell which is filled with water or surfactant solution. The wettability of cores could be changed by saturating cores with crude oil and aging under high temperature (Buckley et al., 1998; Standnes, 2000; Loahardjo et al., 2010). The different wettability could be obtained by different aging time and temperature (Zhou et al., 2000). Water or surfactant solution is drawn into the core by SI. The production of oil aggregated upon the water in the stem of the inverted funnel. However, many oil bubbles are usually attached to the surface of cores especially when the viscosity of oil is high, which have a serious effect on the measurement accuracy of oil production (Fig. 7). Mason and Morrow (2013) reported that the oil bubbles could be removed by gentle shaking or by touching them with a strongly oil-wet rod. However, the application of these methods is also unsatisfactory when the oil bubble is small and the oil viscosity is high.

The weighing method is also the commonly used method to measure oil production by SI (Kewen and Horne, 2000; Li et al., 2006). The schematic illustration of weighing method to measure oil production is shown in Fig. 8. After the core is immersed in water, the weight of the core is recorded and oil production could be calculated according to the density difference between water and oil. However, the measurement results are not accurate, either, if oil bubbles are attached to core surface.

### *3.2 Experimental methods for 1D imbibition*

The imbibition cells method and weighing method could only test the oil production by SI, but give little knowledge on fluid and pressure distribution in cores. Li et al. (2006, 2009, 2011) reported an experimental setup to measure imbibition front and the dead end pressure during the course of SI (Fig. 9). Before the imbibition experiments, the cylindrical surface and the bottom end of the core are sealed by epoxy resin and only the top end of the core is open. In order to detect the imbibition front, some electrodes are embedded into the cylindrical surface of the core. When the imbibition front reaches a particular electrode, the advancing distance of imbibition front could be detected from the onset of electrical conductivity. A pressure transducer is connected to the bottom end of the core to test the dead end pressure.

All the open surfaces of the core are covered by water for imbibition experiments discussed above. However, many matrix blocks are partly covered by water in fractured reservoirs (Bourblaux, 1990; Pooladi-Darvish and Firoozabadi, 2000). Haugen et al. (2014, 2015) designed a special experimental setup to study SI in the core partly covered by water, in which one end of the core was in contact with water and the other end of the core was in contact with oil. In these experiments, initially oil was produced by combination of counter- and co-current imbibition from inlet and outlet of the end face. A little time later, oil production from inlet end face ceased and oil was only produced from the outlet end face by co-current imbibition. The fractions of oil production by co- and counter-current imbibition depend on the oil-water

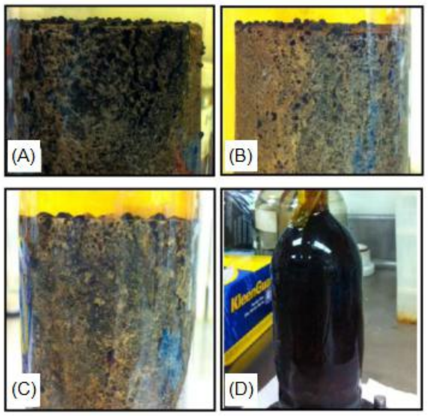



**Fig. 7.** Produced Oil bubbles are attached to core surface (Chen and Mohanty, 2015).

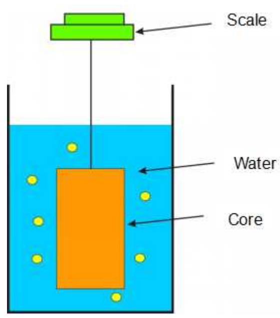



**Fig. 8.** Schematic illustration of setup for imbibition test by weighing method.

viscosity ratio (Haugen et al., 2015; Meng et al., 2016a). Meng et al. (2015, 2016b) and Hauglan (2016) conducted the similar imbibition experiments with unconsolidated porous media (Fig. 11). The unconsolidated porous media was made by packing the glass bead or quartz sand into a glass tube. In their experiments, the imbibition fronts were visible and were recorded versus time.

### 3.3 Imaging techniques

In recent years, the imaging techniques from the medical field have been used to study the fluid distribution in cores during the course of SI. X-ray CT scanning is a commonly

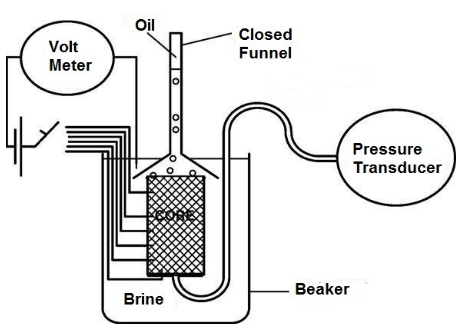



**Fig. 9.** Experimental setup for measurements of oil production, advance of the imbibition front and dead end pressure (Li et al., 2006).

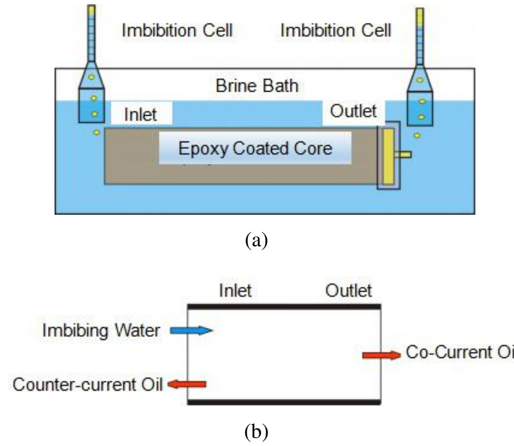



**Fig. 10.** Schematic diagram of experimental setup for SI in core partly covered by water (Haugen et al., 2014).

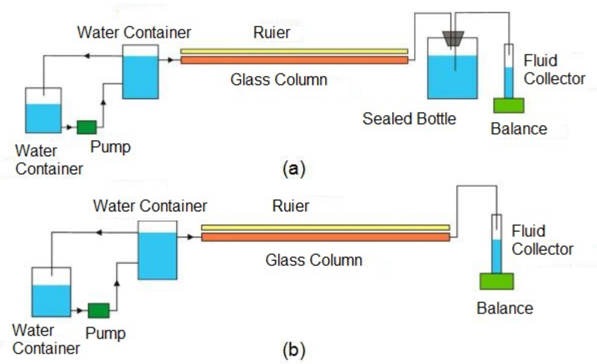



**Fig. 11.** Schematic illustration of setups of imbibition experiments for (a) water-gas system and (b) water-oil system reported by Meng et al. (2015).

used imaging technique to detect fluid distribution pattern (Rangel-German and Kovscek, 2006b). Akin et al. (2000) designed a specific imbibition cells for use in X-ray CT scanner to study multidimensional co-current SI in diatomite (Fig. 12). The original CT data could be converted into the water saturation in the core. The images of water saturation distribution showed that initially the imbibition is sharp and the imbibition is nearly piston-like. As the imbibition front advances toward the end of the core, it becomes more diffuse (Fig. 13). MRI technique is another method to be used to detect the fluid distribution patterns in the core for SI (Baldwin and Spinler, 2002; Wichramathilaka et al., 2011; Fernø et al., 2013). For MRI, the signals of wetting phase are removed by use of heavy water and only non-wetting phase signals are obtained. The non-wetting phase saturation is proportional to the intensity of signals and the wetting phase saturation could be obtained by subtracting non-wetting phase saturation from porosity (Baldwin and Spinler, 2002).

## 4. Boundary condition

In the fractured reservoirs, the development of fracture is complicated (Meza et al., 2010), which results in that the shapes and sizes of matrix blocks are various. Therefore, the boundary conditions of matrix blocks for SI are diverse

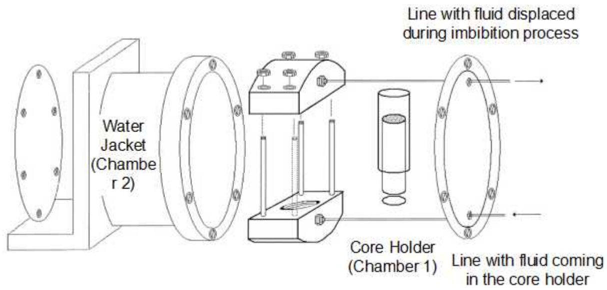



**Fig. 12.** The exploded view of imbibition cell (Akin et al., 2000).

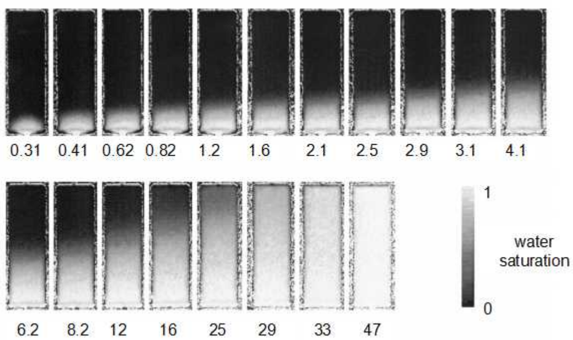



**Fig. 13.** Water saturation images of SI for water-air system in diatomite. The imbibition front for water-oil system is more diffuse (Akin et al., 2000).

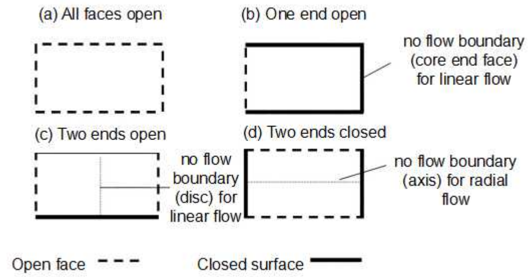



**Fig. 14.** Boundary conditions for counter-current imbibition in cylindrical cores (Morrow and Mason, 2001).

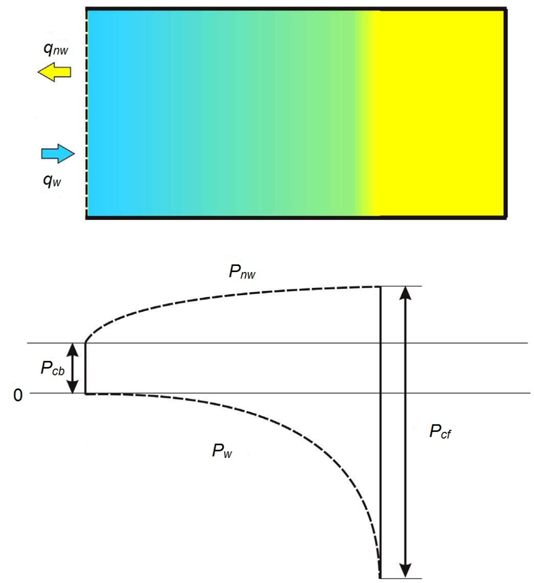



**Fig. 15.** Schematic illustration of SI under OEO boundary condition and pressure profiles in the core (Meng et al., 2017).

during water injection or aquifer invasion into the fractured reservoirs. When the matrix block is completely covered by water, oil production is dominated by counter-current imbibition. However, when the matrix block is partly covered by water, oil production is expelled by combination of co- and counter-current imbibition (Bourblaux, 1990; Pooladi-Darvish and Firoozabadi, 2000).

## *4.1 Completely counter-current imbibition*

The commonly used boundary conditions for cylindrical cores in imbibition experiments include all-faces-open (AFO), one-end-open (OEO), two-ends-open (TEO) and two-ends-closed (TEC) (Zhang et al., 1996; Ma et al., 1997;) (Fig. 14). The most commonly used boundary condition in imbibition experiments is AFO, because it does not need to seal any surface of the core (Babadagli, 2002; Baldwin and Spinler, 2002; Mason et al., 2009; Rostami Ravari et al., 2011). However, the fluid flow patterns under AFO boundary conditions are complex even for homogeneous porous media, which results in that it is very difficult to simulate process of fluid flow by mathematical models. In recent years, many research groups started to focus on the SI under OEO and TEO boundary conditions (Ruth et al., 2007; Li, 2011; Mirzaei-Paiaman et al., 2011; Ruth and Arthur, 2011).

Under OEO boundary condition with incompressible liquids, water imbibition is equal to oil production at any cross-section. The flow direction of water imbibition and oil production is counter-current and linear. The capillary driving pressure is generally dissipated in three parts: the pressure for water invasion, the pressure for oil expelling and the capillary back pressure (Fig. 15) (Li et al., 2009; Li et al., 2011). Many experimental results showed that oil production by SI under OEO boundary condition was linear to the $\sqrt{\text{time}}$ before the imbibition front reaches the end of the core (Fischer and Morrow, 2005; Li et al., 2006; Fernø et al., 2013). However, some recent literature reported that the time exponent was not always 0.5. Cai and Yu (2011) introduced fractal to characterize the tortuosity of imbibition streamline, and theoretically found that the time exponent was related to tortuosity fractal dimension. Hu et al. (2012) demonstrated that the time exponent can reflect the pore connectivity of the tight rock. As the curve degree of flowlines of the SI increases, the pore connectivity decreases and the tortuosity grows, which leads to higher resistance to SI and a time exponent lower than 0.5.

In initial studies of imbibition under TEO boundary conditions, it is generally recognized that the process of imbibition in TEO core was equivalent to the process of imbibition in two independent back-to-back OEO cores, i.e., there was no fluid flow across the middle of the core under TEO boundary condition. However, Mason et al. (2010a) reported that oil recovery from each end face of cores under TEO boundary condition was asymmetrical even for relatively homogeneous cores. In addition, the degree of asymmetry of oil production was different even for three duplicate tests. Mason et al. (2010a) measured the water saturation profile along the core during the course of imbibition by NMR gradient method. It was showed that the amount of water invasion from each end of cores was essentially equal. The asymmetry of oil production can be caused by the difference in capillary back pressure. It is generally believed that relative permeability to aqueous phase is much smaller than relative permeability to oil phase for strongly water-wet porous media (Oak, 1990; Nguyen et al., 2006). The pressure drop in oil is much smaller than the pressure drop in water. The little difference in capillary back pressure can be a small proportion of pressure drop in water but a significant proportion of pressure drop in oil, which results in the high asymmetry in oil recovery. Meng et al. (2016c) introduced a mathematical model for TEO boundary condition by considering the asymmetry of capillary back pressure between the two end faces of the core. It is validated that the small difference in capillary back pressure could result in the high asymmetry in oil production. However, the calculated results showed that the little difference in capillary back pressure has little effect on the total oil recovery from the two open ends. Therefore, oil production by imbibition from TEO core could be approximately equivalent to oil production by imbibition from two independent back-to-back OEO relatively homogeneous cores.

Mattax and Kyte (1962) correlated imbibition data for cores with different sizes but same shapes and boundary condition by use of a characteristic linear dimension of the block. Kazemi et al. (1992) introduced a characteristic length $L_s$ (Eq. (3)), which was defined by the distance from the open face to the core center, to correlate the imbibition data with different shapes and boundary conditions.

$$L_s = \frac{1}{\sqrt{F_s}} = \sqrt{\frac{V_b}{\sum\limits_{i=1}^{n} \frac{A_i}{S_{Ai}}}} \tag{3}$$

where $V_b$ is bulk volume of matrix, $A_i$ is the area open to imbibition at ith direction; $S_{Ai}$ is the distance from $A_i$ to the center of the matrix; $n$ is the total number of surfaces open to imbibition, $F_S$ is the shape factor. By examining the imbibition data for different boundary conditions, Zhang et al. (1996) modified the characteristic length as follows:

$$L_c = \sqrt{\frac{V_b}{\sum\limits_{i=1}^{n} \frac{A_i}{l_{Ai}}}} \tag{4}$$

where $l_{Ai}$ is the distance from the open face to the no-flow boundary condition. The no-flow boundary condition sometimes differs from the center of the matrix. For example, for OEO boundary condition, the no-flow boundary is the sealed end face (Fig. 14).

Zhang et al. (1996) and Ma et al. (1997) reported that the modified characteristic length could closely correlate the imbibition data for cylindrical cores with different sizes and boundary conditions. However, further experiments showed that the modified characteristic length could not closely correlate the imbibition data for irregular cores (Standnes, 2004; Yildiz et al., 2006). The shape of production curves could be different for SI in cores with different geometry shape and boundary condition (Babadagli, 2002; Standnes, 2004; Mason et al., 2012). However, none of existing characteristic length could compensate for the differences in shape of oil production curves. This is an area for future work.

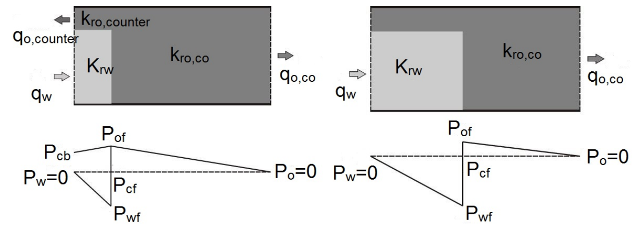



**Fig. 16.** Schematic illustration of imbibition under TEO-OW boundary condition and pressure files in the core (a) oil production by co- and counter-current imbibition (b) oil production by completely co-current imbibition (Meng et al., 2016c).

## 4.2 Combination of co- and counter-current imbibition

If the matrix blocks are partly covered by water, oil is produced by combination of co- and counter-current imbibition. The combination of co- and counter-current imbibition experiments were firstly conducted by Bourblaux and Kalaydjlan (1990). In the experiments, one end face of the core was connected to water and the other end face was connected to oil with all lateral surface sealed, which was called TEO-OW boundary condition by Haugen et al. (2014). The experimental results showed that oil production was dominated by co-current imbibition and oil recovery under this condition was higher than oil recovery by purely counter-current imbibition. Bourblaux and Kalaydjlan (1990) reported that the relative permeability for counter-current imbibition may be lower than that for co-current imbibition by fitting numerical simulation results with experimental results. Haugen et al. (2014) and Meng et al. (2016c) conducted similar experiments by use of consolidated and unconsolidated porous media respectively and gave more detailed discussions on imbibition under TEO-OW boundary condition. Initially, when pressure in oil at imbibition front was larger than capillary back pressure at the inlet end of the core, oil was produced by combination of co- and counter-current imbibition. As the imbibition front advances toward the outlet end of the core, pressure in oil at the imbibition front decreases. When pressure in oil at the imbibition front was lower than capillary back pressure, counter-current imbibition ceases and oil was completely produced by co-current imbibition from the outlet end of the core.

Haugen et al. (2014) established a mathematical model for completely co-current imbibition by assuming piston-like displacement. However, the model did not consider the counter-current imbibition at the beginning of the imbibition under TEO-OW boundary condition. Haugen et al. (2015) developed a mathematical model for SI under TEO-OW boundary condition by assuming that all the pressure would be in the non-wetting phase. However, this assumption may cause serious error with the practical case at the end stages of imbibition. On the basis of the previous work, Meng et al. (2016c) developed a general mathematical model for imbibition under TEO-OW boundary condition and solved it by numerical method. It is reported that the numerical results fitted with the experimental results well.

For correlating oil recovery curves for matrix blocks partly covered by water, there is little literature reporting the characteristic length to account for the differences in geometry shape, size and boundary condition of the matrix blocks. Mirzaei-Paiaman and Masihi (2014) scaled the imbibition data for co-current imbibition by use of the characteristic length obtained from the counter-current imbibition. However, they did not state that how the characteristic length can be calculated for cores partly covered by water and how to determine the open face and the no-flow boundary condition. Standnes (2004) conducted imbibition experiments by use of cubic cores with some surfaces exposed to water and the other surfaces exposed to oil or sealed. The experimental results showed that the water-oil area ratio (WOAR) had significant effect on the rate of oil production. When using the rate of oil production for a cubic core with all surfaces open to water as the reference, the rate of oil production for cores partly covered by water can either be faster (WOAR $>$ 1), equal (WOAR = 1) or slower (WOAR$<$1) than the reference system. However, they also did not give the characteristic length to account for the different boundary conditions. Hamidpour et al. (2015) conducted the one-dimensional and multi-dimensional imbibition experiments with sandstone and limestone partly covered by water. The experimental results were used to verify analytical and numerical models but they also did not give the reliable characteristic length to scale up their imbibition data.

The characteristic length used to account for the differences in geometry shape and boundary condition for combination of co- and counter-current imbibition may be more complex for purely counter-current imbibition. For the partly water covered cores, the flow patterns in the core may be more complex because oil could be produced not only from the oil-exposed surface by co-current imbibition but also from the water-exposed surface by counter-current imbibition. The water-oil ratio can be an important parameter in the characteristic length. In addition, the distance from the inlet face to the outlet face is another hardly obtained parameter. When the water is imbibed from one open surface of the core, oil could be expelled from multi-surfaces of the core. As a result, it is hard to calculate the distance of the fluid flow. How to obtain the characteristic length for matrix blocks partly covered by water will be an important but hard work in future.

## 5. Fluid viscosity

Fluid viscosity has important effect on the rate of oil production by SI from matrix system in fractured reservoirs. The scaling of imbibition data for variation in fluid viscosities is essential importance in prediction of reservoir performances.

**Table 1.** Review on viscosity terms in the scaling equation developed by various authors (Mason et al., 2010b; Cai and Yu, 2012).

| Author | Viscosity ratio |
|---|---|
| Mattax and Kyte (1962) | $\mu_w$ |
| Zhang et al. (1996),<br>Ma et al. (1997) and Yildiz et al. (2006) | $\sqrt{\mu_w \mu_{nw}}$ |
| Li and Horne, (2006),<br>Reis and Cil (1993) and Zhou et al. (2002) | $\mu_w/k^*_{rw} + \mu_{nw}/k^*_{rnw}$ |
| Fischer et al. (2008) | $\mu_w + b^2 \mu_{nw}$ |
| Standnes (2009) | $\sqrt{\mu_w^{VE} \mu_{nw}^{1-VE}}$ |
| Mason et al. (2010) | $\mu_w \sqrt{\mu_w \mu \mu_{nw}}$ |
| Mirzaei-Paiaman and Masihi (2014) | $\mu_{nw} + \sqrt{\mu_w \mu_{nw}}$ |
| Meng et al. (2016c) | $\mu_w + \mu_w^n \mu_{nw}^{1-n}$ |

The most commonly used viscosity term to compensate for the variation in viscosity ratios is the geometrical mean term of the fluid viscosities, which is developed by empirical method from the imbibition data of oil/water viscosity ratios ranging from 1 to 170 (Zhang et al., 1996; Ma et al., 1997). However, further experimental and numerical studies showed that geometrical mean term of the fluid viscosities can only closely correlated the imbibition data for limited range of viscosity ratios. The dimensionless time shows an increased trend with the decreasing oil/water viscosity ratios (Fischer, 2008; Meng et al., 2017). In recent years, the subject of the viscosity term used to scale the imbibition data is moving fast. Mason et al. (2010b), Cai and Yu (2012) presented an extensive review on the development of viscosity term (Table 1).

The effect of fluid viscosity on the final oil recovery by SI is another important subject. Zhang et al. (1996) and Ma et al. (1997) conducted imbibition experiments by use of Berea sandstone with oil-water viscosity ratios ranging from 1 to 170 and observed the residual oil had no significant change with variation in viscosity ratios. Fischer et al. (2006, 2008) conducted imbibition experiments for a wider range of viscosity ratios in Berea sandstone and observed the difference in final oil recovery was small (2% OOIP) as well. Zhou et al. (2002) conducted imbibition experiments in low-permeability diatomite and reported that the final oil/gas recovery decreased dramatically with the increase in oil-water viscosity ratios. Meng et al. (2015, 2016b) conducted imbibition experiments in unconsolidated porous media. The unconsolidated porous media was packing by glass bead or quartz sand, respectively. The geometry of glass beads was regular and the particle size distribution was narrow. The geometry of quartz sand was angular and irregular and the particle size distribution was wide. The experimental results showed final oil/gas recovery for glass-bead-packing was much higher than quartz-sand-packing. In addition, the final oil recovery for glass-bead-packing had no significant change for the increase of oil/gas viscosity. However, the final oil recovery decreased dramatically with the increase in oil/gas viscosity. Meng et al. (2015, 2016a) proposed that the different performance can be resulted from the differences in pore geometry and pore size distribution of the glass-bead- and quartz-sand-packing. However, when the non-wetting phase viscosity was constant with increasing wetting phase viscosity, it is observed that the final oil recovery had no significant change for both glass-bead-packing and quartz-sand-packing (Meng et al., 2016a). Hamidpour et al. (2015) reported the similar observation by use of limestone samples. It is proposed that the imbibition rate decreased with increasing wetting phase viscosity and the capillary number may be consistent for different wetting phase viscosities, which results in the similar final oil recovery (Morrow, 1988; Chatzls et al., 1988).

In the early study, it is usually assumed that the relative permeability for SI was independent of the viscosity ratio. For scaling of imbibition data over wide range of viscosity ratio, effective relative permeability (or average relative permeability) was included in the some scaling equations (Reis and Cil, 1993; Zhou et al., 2002; Li and Horne, 2006). Since the relative permeability curves are not easily obtained in practice, the effective permeability in scaling equation is usually replaced by a single or average value, such as the average relative permeability behind the imbibition front (Zhou et al., 2002; Mason et al., 2010). However, the correlation function could not closely correlate imbibition data over a wide range of viscosity ratio even if using the optimized fixed values of relative permeability. The correlation could be much-improved by a new correlation equation with no explicit relative permeability. It is implied that there can be an implicit correlation between average relative permeability and viscosity ratios by fitting the improved correlations with relative permeability correlations (Mason et al., 2010b). Meng et al. (2017) reported the similar viewpoint by correlating the imbibition data using a correlation function with a single relative permeability curve. Meng et al. (2015, 2016b) found that the average relative permeability to water decreases with increase of non-wetting phase viscosity and the average relative permeability to oil increases with the increase of non-wetting phase viscosity due to the decreasing water saturation for irregular pore structure. The average relative permeability was calculated by fitting the theoretical results of piston-like displacement with the experimental results. Therefore, it could not verify that the real relative permeability curves are dependent on the viscosity ratio. The correlation between relative permeability and viscosity ratio is still a hard work that needs to be studied in the future. If the correlation is obtained, it could be used in the standard scaling equation and a perfect correlation may be obtained for variation in viscosity ratios.

## 6. Wettability

Chilingar and Yen (1983) reported that most carbonate reservoirs were mixed-wet to strongly oil-wet by extensive research work on the wettability of carbonate reservoir cores. Understanding the effect of wettability on SI is essential to prediction of reservoir production performances and enhanced oil recovery in oil-wet fractured reservoirs. Morrow and Mason (2001) made a review on the topic of control and measurement of wettability and SI under oil-wet condition. The subject of the effect of wettability on the SI is moving fast. In this section, we mainly focus on the wettability under reservoir conditions and the method of wettability alteration from originally oil-wet state to a more water-wet state for enhanced oil recovery.

### 6.1 Wettability for reservoir rocks

The investigation showed that the wettability of a solid surface depend on the outermost molecules (Morrow, 1990). The crude oil may contain much high-molecular-weight polar components, which can adsorb on the solid surface and alter the wettability of the solid surface from water-wet to more oil-wet state (Benner and Bartel, 1941; Anderson, 1986). The main mechanisms of wettability alteration by interaction between crude oil and rock surfaces include polar interactions (Clementz, 1982; Dubey and Waxman, 1991), surface precipitation, acid/base interactions (Morrow et al., 1973) and ion binding. The mechanism of wettability alteration for rock surface depends on composition of brine and the solvent quality of crude oil for its asphaltenes (Buckley et al., 1998). The initial water in rock also has an important effect on the adsorption of polar components onto the pore surface. The parts of the rock surface covered by initial water could be protected from adsorption, in which the rock surface may remain water-wet condition (Salathiel, 1973). The form of this wetting state was defined as mixed wettability. The mixed wettability may be the most common wetting state under reservoir conditions (Zhou et al., 2000).

The preparation of cores with different wettability conditions is the basic work for the investigation of effect of wettability on the SI. Since the wettability of rocks could be changed by adsorbing the polar components from the crude oil, the originally water-wet cores were usually saturated with crude oil and aged for different times at different temperatures to achieve various degree of wettability (Jadhunandan and Morrow, 1995; Graue et al., 1999). The components of crude oil have important effect on wettability alteration. Standnes (2000) reported that the wettability alteration is related with the amount of acidic components (high acid number) but not directly related to the amount of asphaltenes in the crude oil. Actually, since the components of crude oil are complex, the wettability alteration can be caused by combination of different adsorption mechanisms (Buckley et al., 1998). Yu and Buckley (1997) and Standnes (2000) reported that the adsorption of polar components onto dry solid surface is a fast process and is not strongly dependent on the aging time. However, the adsorption of polar components on the prewetted surfaces is strongly dependent on the aging time and it could be divided into two stages: initially fast adsorption and followed by slow rearrangement of adsorbate. In order to obtain uniform wet cores, the outmost layer of the aging core was usually removed (Standnes, 2000) or dynamic method was used (Fernø et al., 2010). The mixed-wettability is obtained by saturating the core with initial water saturation. The combined effect of polar components interaction and the distribution of initial water saturation could cause a wide range of wetting conditions

(Zhou et al., 2000; Morrow and Mason, 2001).

Contact angle test is the most commonly used method to quantitatively evaluate the wettability. However, measurement results of contact angle depend on the surface contamination, the heterogeneity of adsorption, the roughness of solid surface and measured methods (Anderson, 1986; Morrow, 1990). In addition, the contact angle could not take into account the mixed-wettability in porous media. Amott (1960) measured the average wettability of a core by combination of imbibition and forced displacement efficiency. The ratio of oil production by SI to the total oil production is defined as the wettability index to water, $I_w$; similarly, the ratio of water production by SI to total water production is defined as wettability index to oil, $I_o$. The difference between water and oil wettability index, $I_w - I_o$, defined as Amott index, $I_{AH}$, which is used to quantitatively evaluate the wettability of the core. USBM method is another method to quantitatively evaluate the average wettability of a core (Donaldson et al., 1969; Donaldson et al., 1980; Donaldson, 1981). In USBM method, the wettability index is defined as follows:

$$W = \log \frac{A_1}{A_2} \tag{5}$$

where $A_1$ and $A_2$ are the area under oil- and brine-drive capillary curves. The wettability index of USBM method is more sensitive than Amott method in neutral wettability. However, the Amott method has an advantage in determining whether a system is mixed wettability (Anderson, 1986).

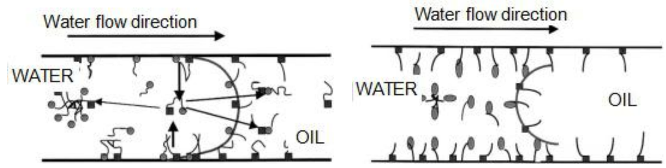
The SI in cores with various wetting conditions is quite complex. The wettability of the cores not only has serious effect on the rate of oil production but also on the final oil recovery and the shapes of imbibition curves (Zhou et al., 2000; Qiao et al., 2015). The rate of imbibition in weakly water-wet cores can be extremely slower than strongly water-wet cores. Oil production by imbibition decreases with the decrease of water-wet wettability, which is opposite to the oil recovery by waterflooding for decreasing water-wet wettability (Xie and Morrow, 2000; Zhou et al., 2000). The SI is more complex in cores with mixed wettability. Standnes and Austad (2000) reported that the imbibition rate was fast initially, however, decreased dramatically after producing 7% of original oil in place (OOIP). The fast oil production may be caused by the strongly water-wet parts of rock pores. The shape of imbibition curve for mixed-wet cores is different from the strongly water-wet cores. The imbibition data could not be scaled by a single parameter like wettability index or contact angle. For oil-wet cores, capillary pressure act in the negative direction and the rate of oil production can be very low or nonexistent. In order to improve oil production by SI from mixed- or oil-wet fractured reservoirs, the wettability of matrix blocks should be altered.

## 6.2 Wettability alteration for enhanced oil recovery

In mixed-wet and oil-wet fractured reservoirs, the capillary force for SI is weak or acting as the negative role, which causes that oil production from matrix system by SI is low or nonexistent (Freer et al., 2003; Hirasaki and Zhang, 2004; Hammond and Unsal, 2011). The oil production in oil- and mixed-wet fractured reservoirs by waterflooding is low due to the weak SI in matrix system. On average, about 80% of OOIP remains in fractured reservoirs after conventional water-flooding (Chen and Mohanty, 2013; Chen and Mohanty, 2015). The oil recovery from such reservoirs could be improved by altering the wettability of reservoir rocks to more water-wet state (Spinler et al., 2000; Adibhatla et al., 2005; Adibhatla and Mohanty, 2006; Kumar et al., 2008; Gupta and Mohanty, 2010).

Surfactant treatment is the most commonly used method to alter the wettability of reservoir from oil-wet to more water-wet state. Austad et al. (1997, 1998) conducted the SI in water-wet, mixed-wet and nearly oil-wet low permeable chalk by use of water and cationic surfactant. The experimental results showed that negligible extra oil was produced by use of surfactant after water imbibition for water-wet chalk (Austad et al. 1997). For nearly oil-wet chalk, the rate of oil production was extremely slow and oil recovery was very low (about 10% OOIP) by use of water. When the brine was substituted by cationic surfactant, oil was produced immediately from all surfaces of the core, which indicated that oil was produced by counter-current imbibition. In addition, no gravity segregation of oil saturation in core was observed by cutting the core, which confirmed that oil produced by counter-current imbibition. Therefore, the main mechanism of improving oil recovery can be that wettability of chalks was altered from oil-wet to preferentially water-wet condition by surfactant. Although the interface tension decreases, the rate of oil production increases by counter-current imbibition. It is implied that the increase of capillary pressure by wettability alteration compensated for the decreasing of interface tension.

Standnes (2000) and Standnes and Austad (2000) conducted SI experiments in low permeability oil-wet chalks by use of cationic and anionic surfactants, respectively. The experimental results showed that both cationic and anionic surfactant could improve oil recovery from oil-wet chalks by altering the wettability of chalks. However, the cationic surfactant performed much better than anionic surfactant. It is supposed that adsorbed anionic materials on rock surfaces, which made the rock surface oil-wet, could be stripped by generated an ion-pair between the cationic heads of the surfactant molecules and polar components. However, for anionic surfactant, it is supposed that the hydrophobic part of surfactant molecules adsorbed on the hydrophobic part of the polar components on the rock surface. The hydrophilic head groups of adsorbed surfactant may form a small layer covering the primarily oil-wet rock surfaces, which could alter the wettability of rocks from oil-wet to water-wet state. In order to verify the ion-pair mechanism of wettability alteration, Salehi et al. (2008) conducted the imbibition experiments with cationic and anionic surfactants by use of sandstones. Buckley et al. (1998) reported that the pore surface of carbonate rock is usually positively charged and adsorbs acidic components in the crude oil. The pore surface of sandstone is usually negatively charged and adsorbs basic components from the crude oil. Therefore, after the aging process in crude oil, the pore surface of carbonate is usually covered with negatively




(a) Cationic surfactant (b) Anionic surfactant

**Fig. 17.** Schematic illustration of mechanism for wettability alteration of oil-wet chalks by (a) cationic and (b) anionic surfactant (Standnes and Austad, 2000).

charged acidic components and the pore surface of sandstone is usually covered with positively charged basic components. If the ion-pair mechanism is correct, the anionic surfactant should perform better than cationic surfactant in the wettability alteration of sandstone from oil-wet to water-wet. The experimental tests showed that the rate of oil production is faster and oil recovery is higher for imbibition in sandstones by use of anionic surfactant than that by cationic surfactant. The further imbibition test by use of the anionic surfactant with two negative charges on the headgroup performed better than that with one negative charge. This is consistent with the hypothesis of ion-pair mechanism for wettability alteration because the ion-pair generation is controlled by the electrostatic interactions.

Hammond and Unsal (2009) presented a numerical model for the flow of surfactant solutions into an oil-wet capillary tube by adsorbing mechanism (surfactant adsorption in the oil-wet surface) of wettability alteration. The numerical results showed that the contact angle during the course of SI is close to $\pi/2$ and the advancing velocity of meniscus is quite slow by use of realistic values of bulk diffusion. The advancing velocity of meniscus is dominated by the resistance of convection of surfactant from the oil-water meniscus onto the walls of capillary across three-phase contact line at early times and is dominated by rate of surfactant diffusion in the aqueous phase. Some research groups reported that surfactant are not only adsorbed onto the solid surface behind the advancing meniscus but also are transported onto the solid surface ahead of the advancing meniscus through the three-phase contact line (Eriksson et al., 2001; Kumar et al., 2003; Kumar et al., 2008). Hammond and Unsal (2010) developed the numerical model on the basis of previous work by considering the mechanism of surfactant transported across the three-phase contact line. Their numerical results showed that advancing velocity of the meniscus is slower than this mechanism is not presented. This is because the adsorption of surfactant on the solid surface in the front of the advancing meniscus decreases the interface energy of solid surface and makes the contact angle larger. The surface is more oil-wet, the rate of imbibition is lower. In addition, they reported that there is a threshold concentration of surfactant below which the surfactant solution could not be drawn into the oil-wet capillary. On the basis of these work, Hammond and Unsal (2011) developed a numerical model by considering the ion-pair mechanism of wettability alteration. The numerical calculation showed that the advancing velocity of oil-meniscus increases dramatically when the wettability alteration of oil-wet solid surface is dominated by ion-pair mechanism. In addition, the threshold of surfactant concentration for SI is not existent. The stripping of adsorbed organic material off the solid surface is controlled by the surfactant molecules into the vicinity of the oil-water meniscus. So long as the surfactant molecules are existent in the aqueous phase, the ion-pairs could form and the wettability of oil-wet solid surface would be altered to more water-wet by stripping the organic material off the solid surface.

In addition to the simple cationic and anionic surfactant solutions, many other methods have been introduced to change the wettability of oil-wet cores to more water-wet condition. Somasundaran and Zhang (2006) reported that mixed surfactants were more effective in wettability alteration than single surfactants due to synergetic effects. A natural-based surfactant, which is low cost and environmental safety, was introduced to alter the wettability of carbonate rocks by Ahmadi et al. (2015). Zhang et al. (2007) found that the seawater was another important injection fluid to improve oil recovery from fractured carbonate reservoirs. They supposed that three determining ions: $Ca^{2+}$, $Mg^{2+}$ and $SO_4^{2+}$, have a significant effect on the wettability alteration of chalks from oil-wet to water-wet. Qiao et al. (2015) developed a numerical model which considering the interaction among ions in the aqueous phase ($Ca^{2+}$, $Mg^{2+}$ and $SO_4^{2+}$), crude-oil acidity and solid surface to predict the wettability alteration and enhanced oil recovery for chemical flooding in mixed-wet reservoirs. They reported that the concentration of sulfate have an important effect on wettability alteration, whereas the cations have relatively little effect on wettability alteration. Zhang et al. (2014) introduced the effect of nanoparticles on the wettability alteration of oil-wet carbonate rocks. Chen and Mohanty (2013, 2015) studied the performance of wettability alteration by cationic and anionic surfactant in harsh conditions (high temperature and high salinity). It is reported that the wettability of oil-wet carbonate rocks could be altered by cationic surfactants in harsh condition, whereas the wettability could be altered by anionic surfactant only when the brine salinity and concentration of divalent-ion are reduced. The effect of gravity on SI in oil-wet chalk by use of surfactant as the wettability modifier was investigated by Høgnesen et al. (2006) and Ravari et al. (2011).

The ultimate purpose of investigation of wettability alteration by surfactant is improved oil recovery from mixed- or oil-wet fractured reservoirs. In the field application, the environmental impacts, the cost of surfactant and the amount of improved oil production should be considered. The rate of SI should not be too slow for a practical process. Although the cationic surfactant performed better than anionic surfactant, the cationic surfactant is expensive. The adsorption of surfactant should be considered and the best concentration of the surfactant for field application can be higher than in the imbibition experiments. The numerical simulation of wettability alteration and improved oil recovery in mixed- and oil-wet fractured reservoirs should be investigated systematically by considering the mechanism of wettability alteration in porous media and fractured reservoirs.

## 7. Conclusions and future work

The study of SI is growing fast in the past few years. However, many questions are still confusing and controversial and much theoretical and experimental work needs to be done in the prediction of reservoir production performance and enhanced oil recovery.

Much insight into the fundamental physics mechanism of SI has been obtained from the idealized interacting tube model. The micromodels at pore scale could provide the patterns of entrapment of non-wetting phase and fluid distribution during the imbibition process. However, many questions still need to be answered. The mechanism of entrapment at different pore-throat structures and the effect of fluid viscosity on the entrapment of non-wetting may be observed through the micromodels. The pores for oil production, which is corresponding to the capillary back pressure, can be detected. The patterns of fluid displacement under various boundary conditions should be investigated.

Since the boundary conditions for matrix blocks in fractured reservoirs are diverse, oil production by SI under much more boundary conditions should be tested, especially for the partly water-covered boundary conditions. The characteristic length should take account of more variables, such as the water- and oil-connected area, the relative location of water- and oil-connected surface, the shape and size of the core. In addition, the shape of imbibition curves for different boundary conditions may be different. However, the consistent value of characteristic length, which is independent of the imbibition time, could not change the shape of imbibition curves. The development of the characteristic length that could change the shape of imbibition curves can be an important but hard work in the future.

The effect of fluid viscosity on oil production by SI should be studied by use of different types of porous media. The pore-throat structure and pore size distribution may have significant impact on the rate of oil production and the entrapment of oil for the SI. The effect of fluid viscosity on oil production and relative permeability can be different for different types of cores, which may have serious effect on the scaling results for variation in viscosity ratios.

The mechanism of SI under mixed- and oil-wet condition is far from completely understanding. The evaluation of wettability for mixed-wet cores is difficult, which causes the difficulty in quantitative evaluation of oil production by SI. The fluid distribution patterns and the entrapment of oil in the mixed-wet cores need to be studied. The two-dimensional micromodels at pore scale may be an attemptable choice. More types of surfactant should be tested in the efficiency of wettability alteration and enhanced oil recovery by use of different types of cores under different degrees of wettability conditions. In field application, more factors should be considered, including surfactant type, adsorption, optimized concentration, cost and environmental impact. The optimization of chemical flooding for a specific fractured reservoir is still a hard work. The numerical simulation of wettability alteration and enhanced oil recovery by chemical agent should be further studied. The combination of numerical simulation and experimental investigation can be a good choice for the optimization of chemical flooding in mixed- or oil-wet fractured reservoirs.

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