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Review Article

Foam flow in porous media: Concepts, models and challenges

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ABSTRACT

This paper aims to elaborate foam concepts and foam flow modeling approaches in porous media. Furthermore, this review summarizes and compares all existing foam models approaches including Mechanistic, Semi-Empirical and Empirical. Finally, it discusses foam models in different reservoir simulators in detail and presents different approaches for obtaining models' parameters in simulators. The comparison results showed that Emprical models are more suitable for simulation study due to less required paramters and faster calculation; however, these models might not be a appropriate in transient foam flow. Moreover, the challenges about he results of this review provide an valuble insight about foam behaiviour.

1. Introduction

Recently, gas flooding became one of the most accepted and widely used methods for enhanced oil recovey (EOR) (Franklin and Orr, 2007). Fig. 1 illustrates the 38.4% and 68.4% contribution of gas flooding methods in the worldwide enhanced oil recovery. The gas injection phases are nonhydrocarbon gases such as flue gas, nitrogen, carbon dioxide, and even hydrogen sulfide and hydrocarbon gases such as methane and mixture of methane to propane (Mohamed El Gohary, 2012).

There are two different schemes for gas injection process; miscible gas flooding and immiscible gas flooding. In the first scheme, the governing mechanisms for oil production are swelling the oil phase as well as reducing the oil viscosity. This mechanism leads to an increase in the microscopic efficiency compared to water flooding (Lake, 1989). Generally, the hydrocarbon gases and carbon dioxide are utilized as the gas phase for miscible gas injection. In the second scheme, only a small portion of the gas phase is dissolved in the oil and the main purpose of this method is to increase the reservoir energy (Green and Willhite, 1998). This mechanism increases the macroscopic efficiency which is usually is less than water flooding. The nitrogen gas is a good candidate for the immiscible process because it is hard to achieve the miscibility point at common reservoir pressures.

The adverse mobility ratio of gas during gas displacement is considered as the crucial problem of gas flooding (Hanssen et al., 1994; Liu et al., 2011; Farzaneh and Sohrabi, 2013; Rossen et al., 2014; Farajzadeh et al., 2016). Mobility ratio is the mobility of the displacing fluid divided by that of the displaced fluid ($M_{displacing}/M_{displaced}$). The favarable mobility ratio is one or less than one to make a piston like displacment; however, the mobility ratio for gas flooding is between 10 and 100 which is considered as unfavorable mobility ratio (Displacement Efficiency of Immiscible Gas Injection, 2013). This poor mobility ratio arises from the significant difference between the viscosity of gas and oil compared to the viscosity of water and oil. This difference in viscosity results in higher mobility of gas to oil, consequently, leads to an unfavorable mobility ratio.

This unfavorable mobility ratio results in viscous fingering phenomena and premature breakthrough of the gas phase, eventually, poor sweep efficiency (Boeije and Rossen, 2015). The poor sweep efficiency increases the cost of gas injection and recycling process (Krause et al., 1992). This situation becomes worse in heterogeneous reservoir since gas channeling phenomena occurs through the higher permeable layers and the gas bypasses the oil (Chang et al., 1990). Furthermore, normally the gas density is less than one-third of oil density at reservoir condition (Jamshidnezhad et al., 2008), this large difference brings another disadvantage. It causes phase segregation and gas overriding to the top of the reservoir (Rossen et al., 2014). The segregation phenomenon also decreases the sweep efficiency of gas flooding, consequently, the huge amount of oil phase will be bypassed by the gas phase. Fig. 2 illustrates these gas flooding mobility issues.

One of the common methods to reduce the gas mobility as well as increase the sweep efficiency is water-alternating-gas (WAG) injection. The WAG was introduced by Caudle et al., in 1957 to mitigate the gas mobility problem (Dyes et al., 1954). The microscopic displacement of the oil by water is less that by gas due to higher interfacial tension between water and oil. On the other hand, the macroscopic

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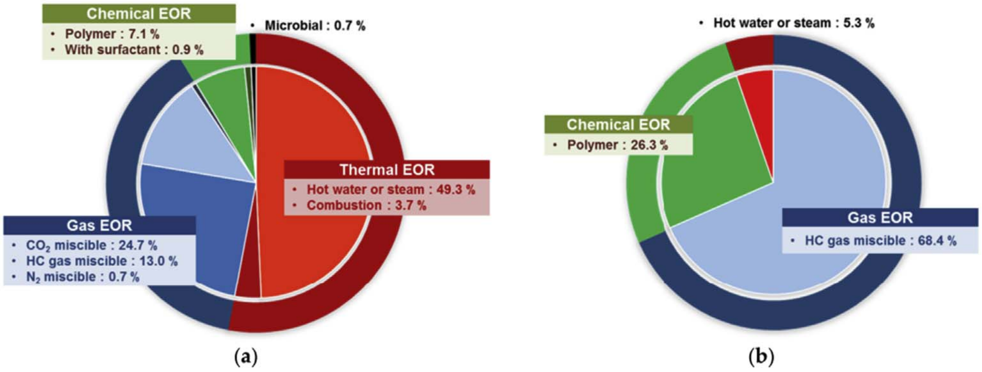

Fig. 1. The contribution of different EOR methods in the world for onshore and offshore fields in 2016. (a) Onshore fields; (b) Offshore fields (Kang et al., 2016).

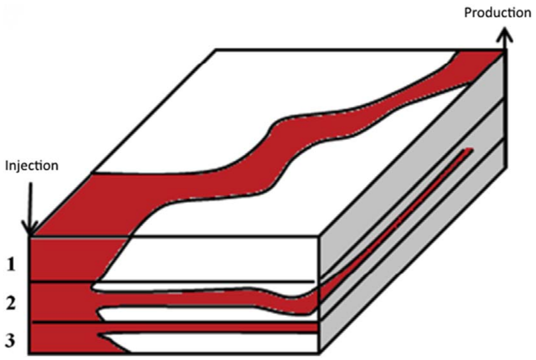

Fig. 2. Poor sweep efficiency of gas flooding issues listed as; (1) viscous fingering, (2) gas channeling, and (3) gas overriding (Hanssen et al., 1994).

displacement of the oil by water is better than by gas due to lower mobility of the water. Therefore, the combination of these two methods improves the recovery due to the reduction of gas mobility (Christensen et al., 1998). However, the pilot test for WAG application and simulation studies shows only a modest reduction in gas mobility; the segregation and viscous fingering reoccur (Surguchev et al., 1995; Righi et al., 2004; Sohrabi et al., 2000; Christensen et al., 1998).

The foam assisted process is a potential solution to tackle all the mentioned problems in gas flooding as well as WAG (Bond and Holbrook, 1958; Kovscek et al., 1995; Farajzadeh et al., 2008; Wang and Li, 2016). Foam is able to control the gas mobility properly, by ceasing a large amount of gas phase through the porous media and increase the apparent viscosity of gas phase (Bernard et al., 1980; Hirasaki and Lawson, 1985). Wang and Li also showed that mobility reduction by SAG was much higher than by WAG Method while flowing surfactant solution and propane alternately through glass beadpack. They also observed that higher SAG ratio resulted in greater mobility reduction. (Wang and Li, 2016).

Adebayo, Kamal, & Barri conducted a series of laboratory experiment on rock samples in both vertical and horizontal flow directions to compare the effects of water alternating gas (WAG) and surfactant alternating gas (SAG) as mobility control methods versus continuous gas injection method with respect to pressure drop and trapped gas saturation. Their results showed that the SAG method significantly increased trapped gas saturation for both horizontal and vertical flows while WAG method showed opposite behavior (Rasheed et al., 2017).

Foam also reduces the relative permeability of gas drastically. Bond and Holbrook (1958) defined the concept of foam application for gas mobility reduction for the first time. This reduction is shown by mobility reduction factor (MRF) which is the mobility ratio of foam divided by gas mobility. The MRF can be calculated by dividing the pressure drop of foam flooding by pressure drop of gas flooding ($MRF = \Delta P_{foam}/\Delta P_{gas}$) (Nguyen et al., 2000).

There are various examples of foam's field application for EOR such as Kern River and Midway Sunset fields in the US (Hirasaki, 1989; Patzek and Kolnls, 1990; Friedmann et al., 1994), Snorre field in Norway (Tore et al., 2002; Aarra et al., 2002), Prudhoe Bay field in the US (Krause et al., 1992), San Andres field in the US (Prieditis and Paulett, 1992), and Oseburg field in Norway (Aarra and Skauge, 1994; Hoefner et al., 1995). These implementations, results in significant increase of recovery factor, for instance in San Andres using foam–assisted process improve an oil production by 10%–30% (Prieditis and Paulett, 1992). The mode of foam application would depend on the nature and source of the problem (Turta and Singhal, 2002).

In the field application, foam is injected in different ways which are more diverse compared to that in the laboratory (Turta and Singhal, 2002). There are fives types of foam injection methods in the field and laboratory applications;

- Pre-formed foam injection: In this method, foam is generated outside the porous media. Foam can be generated either at the surface via a foam generator or through the tubing during downward flow (Turta and Singhal, 2002). The potential of controlling the foam injection quality and foam's strength are the feature of this method.
- Co-injection foam: In this method, foam is formed inside the formation few meter from the injector well by injecting both phases of gas and surfactant solution. This method is also called “in-situ foam” generation. Two tubing strings are required for this method, one for gas phase and second for surfactant solution (Turta and Singhal, 2002).
- Surfactant-Alternating-Gas (SAG) foam injection: Foam is formed inside the porous media by consecutive injection of gas and surfactant solution in this method. During SAG foam process, a surfactant solution is drained by the gas phase, therefore, this method is also called “drainage foam” injection. The foam under this method is not limited to entry zone but wherever the gas has the contact with invaded surfactant solution, the foam can be generated (Rossen and Boeije, 2013).
- Dissolved surfactant foam injection: according to several studies, some surfactants are able to dissolve in carbon dioxide under the supercritical condition (Le et al., 2008; Ashoori et al., 2010). In this method, only one phase is injected into the reservoir and the foam is generated once it meets the formation water.
- Simultaneous different layers foam injection where the gas phase and surfactant solution phase are injected simultaneously but in different sections of the well. This method can be performed in both vertical and horizontal wells. The gas is injected from the lower section/lower horizontal well and the surfactant is injected from upper section/upper horizontal well. Because of gravity segregation phenomena, the gas and surfactant phase can meet each other and generate the foam inside the formation (Stone, 2004; Rossen et al., 2010).