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Effect of wettability on oil recovery and breakthrough time for immiscible gas flooding

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ABSTRACT

The effect of wettability on oil recovery at higher water saturation is still not fully understood, especially in the case of mixed wettability. This study was conducted to examine the effects of wettability on oil recovery and breakthrough time through experiments for two wettability conditions (water-wet and mixed-wet) and three water saturations (20%, 40%, and 60%). Clashach sandstone core with a porosity of 12.8% and a permeability of 75 md was utilized as the porous media. Immiscible gas flooding was performed by injecting nitrogen gas into the core at room temperature and pressure. The results showed 54.3% and 48.8% of the initial oil in place (IOIP) as the ultimate oil recovery at 40% water saturation from mixed-wet core and water-wet core respectively. In contrast, the water-wet core displayed better results (32.6% of the IOIP) in terms of breakthrough time compared to the results of water-wet core (10.6% of the IOIP) at the same water saturation. In conclusion, oil recovery was found highly dependent on water saturation while breakthrough time was mainly affected by the wettability of the cores.

KEYWORDS
Breakthrough time; enhanced oil recovery; immiscible gas flooding; wettability; water saturation

1. Introduction

The amount of water flooding residual oil recovered by immiscible gas flooding depends on how well understood the parameters that control the oil recovery by immiscible gas flooding such as wettability, gas/oil viscosity contrast, water saturation, and mobility ratio are. In tertiary recovery by immiscible gas flooding process, wettability is considered to be the most prominent parameter controlling the microscopic and macroscopic displacement efficiencies (Emami Meybodi et al., 2011a; Emami Meybodi et al., 2011b; Mehranfar and Ghazanfari, 2014). It plays a major role in determining the location, flow, and distribution of fluids inside the reservoir. Wettability in its generic term aptly describes the preference of a particular solid—making up the reservoir rocks—to be in contact with a particular fluid rather than another. An accurate determination and solid knowledge of the wettability is fundamental to understanding the behavior of fluids in multiphase flow. Reservoir wettability can be classified into water-wet, neutral-wet, intermediate wettability, mixed wettability, fractional wettability, or oil-wet (Abdallah et al., 1986; Suicmez et al., 2008b; Zahoor et al., 2009; Sharma and Mohanty, 2013; Bassioni and Taha Taqvi, 2015; Chaudhary et al., 2015). The water-wet condition is a wetting state where only water is in contact with the reservoir rocks. Similarly, the oil-wet condition is a wetting state where only oil is in contact with the reservoir rock. Where the reservoir rocks neither imbibe the water phase nor the oil phase a

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neutral-wet condition exists. On the other hand, nonuniform wettability is wetting state that has different wetted areas in the same system that can be characterized as either water-wet or oil-wet areas. A few of early studies on the effect of wettability on oil recovery were based on the simplistic assumption that the wettability is nonuniform throughout the reservoir. However, this assumption was challenged by many authors who postulated the presence of heterogeneity in the wettability of rocks (Fernø et al., 2007; Bognø, 2008; Haugen et al., 2007; Haugen, 2010; Cao et al., 2015). For instance, Suicmez et al. (2008a) investigated the effects of wettability and pore-level displacement on hydrocarbon trapping. It was found that low residual oil saturation is due to the presence of nonuniform wettability condition in which water-wet and oil-wet conditions occur at the same time. Several studies have been conducted on the effect of wettability on the oil recovery by immiscible gas flooding (Oren and Pinczewski, 1994; Vizika and Lombard, 1996; Wylie and Mohanty, 1997). For instance, Oren and Pinczewski conducted a study on 2D glass micromodel to investigate the mobilization and the oil recovery of water flooding residual oil by immiscible gas flooding under strongly water-wet and oil-wet conditions. It was found that oil recovery under water-wet condition is less than that for oil-wet condition. These results contradict with those obtained by another work conducted by Vizika and Lombard, who studied the role of wettability on the oil recovery by immiscible gas flooding under gravity drainage for water-wet, mixed-wet, and oil-wet sand pack. Sand-pack with an average porosity of 35% and absolute permeability ranged between 10 to 14 darcy was used as the porous media. It was found that the highest oil recovery is obtained for both water-wet and mixed-wet at positive spreading coefficient. The experiments on water-wet and mixed-wet sand-pack were conducted under irreducible water saturation of 16.6% and 18%, respectively. Both previous and recent experimental results on the effect of wettability on the oil recovery for immiscible gas flooding on porous media point to the divergence in conclusions regarding to the best wetting conditions for maximum oil recovery. In addition, most of those experimental investigations have been conducted under low mobile or immobile water saturation conditions. It is clearly obvious that there is lack of studies on the effect of wettability on oil recovery at high water saturation levels.

2. Experimental

2.1. Setup

A low-pressure core flood apparatus was set up to conduct the gas flooding experiments. The entire core flooding system consisted of (a) cylindrical piston for injecting the fluid into the core, (b) Hassler type core-holder, (c) pressure gauge for measuring the pressure drop across the core during the core flooding process, (d) a measuring cylinder, (e) gas flow meter, and (f) vacuum pump. Two nitrogen gas cylinders were used in this experiment. The first cylinder was used for gas injection during the gas flooding experiments, as well as to operate the cylindrical piston that was used to inject the fluid into the core. The second gas cylinder was used to provide confining pressure for the core flooding experiments.

Clashach sandstone core was mounted horizontally inside a core-holder at pressure difference range of 1–2 psia and room temperature to eliminate the effect of gravity. Pressure gauge was used to measure the pressure difference across the porous media. Fluid injection such as oil and brine into the porous media was accomplished by means of injection piston using gas as the driving force. The injection rate was in a range of 0.1–1.0 cc/m while gas injection was 0.2 cm^3/min for all the gas flooding experiments. At the outlet, 50 mL graduated cylinders were used to collect the fluids and fluid volume was measured. Gas flow meter and liquid flow-meter were used to measure the amount of gas and liquid injected into the porous media. Vacuum pump was used to sack the air from porous media during the cleaning process.

2.2. Fluid system

The oil used in this study was a mixture of 50% n-heptane and 50% paraffin oil that was used to prepare low viscosity oil. Oil with 1.37 cp viscosity was obtained and used instead of crude oil. Formation brine

Table 1. Brine Composition used in the study.

Total salinity, ppm	Salt category	Chemical formulation	Salinity, ppm	Quantity, g	%
40000	Sodium chloride	NaCl	35000	35	87.5
	Calcium chloride Dihydrite	$CaCl_2.2H_2O$	5000	5	12.5

was designed to have 4.0% by weight total dissolved solid. It was prepared by dissolving 35 g of NaCl with 5 g of $CaCl_2.2H_2O$ in 1 L of distilled water. The density of the brine was 1.069 g/cm^3 and its viscosity was 1.09 cp. Table 1 shows the composition of artificial formation brine.

2.3. Design

Pure nitrogen was used as an injection gas in all the core floods. The gas flooding process was immiscible gas flooding process at a pressure difference ranged from 1 to 2 psia. Experiments conducted were secondary immiscible gas flooding at 20% water saturation, tertiary immiscible gas flooding at 40% water saturation and tertiary immiscible gas flooding at 60% water saturation. These three types of experiments were conducted in both water-wet and mixed-wet cores.

2.4. Creation of mixed-wet core

For the mixed-wet cases, a procedure that is similar to (Narahara et al., 1993) was followed to create the mixed-wet core. Normal heptane was mixed with Nemba crude oil at 100°F for 10 minutes and injected into core. The mixture was 20% n-heptane and 80% Nemba crude oil. The core was then aged with the mixture inside the pore space for three days. After three days of aging, the mixture used to create the mixed wettability is displaced by 20 cp white oil. Spontaneous imbibition and Amott test were used to make sure that the aging process was effective in changing the core wettability.

3. Results and discussion

3.1. Wettability measurements results

The core wettability state was determined by the Amott test, which is based on the principle of spontaneous and forced imbibition of oil and water into the cores (Alveskog et al., 1998). In this experiment, the Amott test was utilized to determine the wettability of the core before and after treating with crude oil/n-heptane mixture. Two experiments were conducted to test the wettability of the core. The results obtained from both tests are illustrated in Table 2. Wettability index for the first experiment conducted on the Clashach core before any treatment shows that the core is a water-wet core. According to Amott wettability test, the sample is water-wet when $+0.3 \leq I_w \leq 1.0$. The wettability index for the first experiment was 0.418. This wettability index value falls in the range proposed by the Amott test for water-wet sample. However, the obtained wettability index value does not show to be very strongly water-wet, it was concluded that the core is water-wet. The low value of wettability index was due to the short time for imbibition process. On the other hand, the result obtained after conducting the crude oil/n-heptane mixture treatment shows a slight change in the wettability of the core from water-wet to a wettability state that is a mixed of water-wet and oil-wet. This wettability change was recognized by the reduction of the wettability index to 0.189. According to (Cuiec, 1984) who further narrowed down the interpretation

Table 2. Amott spontaneous imbibition test results on Clashach sandstone core before and after treatment with crude oil/n-heptane mixture.

Core type	V_{wsp}	V_{wt}	V_{osp}	V_{ot}	I_w	Wettability
Clashach before treatment	0.1 cm^3	5.2 cm^3	2.3 cm^3	5.25 cm^3	0.418	W-W
Clashach after treatment	0.95 cm^3	4.7 cm^3	1.9 cm^3	4.85 cm^3	0.189	M-W

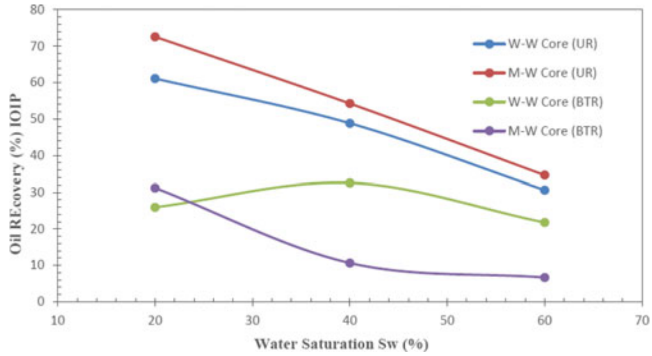

Figure 1. Ultimate and breakthrough oil recovery versus water saturation for water-wet and mixed-wet core.

of the wettability index by stating that the system is intermediate (or mixed) wet when $-0.3 \leq I_w \leq 0.3$. Based on this interpretation, it is clear that the wettability of the treated Clashach sandstone core was altered from completely water-wet to a nonuniform wettability condition in which water-wet and oil wet conditions occur at the same time.

Comparisons between the results obtained from both tests also support the presence of heterogeneous wettability in the treated core. For instance, the volume of brine displaced by oil (V_{wsp}) by spontaneous imbibition in core before any treatment was 0.1 cm^3, whereas in treated core the volume of brine displaced by oil was 0.95 cm^3. This increase in the volume of oil spontaneously embedded into the core clearly indicates the presence of some areas in the treated core that demonstrate an oil-wet state. These areas are believed to be the large pore spaces of the core due to the fact that oil phase used to change the wettability can only enter the large pores easier than the small pores due to high capillary entry pressure (Haugen et al., 2010; Fernø et al., 2011).

3.2. Effect of wettability on oil recovery

The gas flooding experiments conducted on water-wet and mixed-wet Clashach sandstone core at different water saturations showed that oil recovery varies with the wetting state of the core. The experiments were carried out using nitrogen as the injected gas and 1.37 cp oil at room temperature and a pressure that ranged from 1 to 2 psia. The gas flooding process was conducted as a secondary process for the core with 20% water saturation and as tertiary recovery process after water flooding for both cores with 40% and 60% water saturation respectively. Figure 1 shows the results of the gas flooding experiments on water-wet and mixed-wet core. The results clearly depict that the ultimate oil recovery for mixed-wet core is higher than that for water-wet core. In contrast, the results also show that the breakthrough recovery for mixed-wet core was less than that that for water-wet core. For instance, the ultimate oil recovery for mixed-wet core at 40% water saturation was 54.3% of the IOIP, while in water-wet core with the same water saturation it was 48.8%. In contrast, breakthrough recovery of water-wet was higher than that for mixed-wet at the same water saturation with 32.6% and 10.6% of the IOIP, respectively. Unlike the water-wet core, large amount of the oil recovered in mixed-wet core occurs after the breakthrough of nitrogen at high water saturation. In addition, higher water production was observed from mixed-wet core than that of water-wet core. At a water saturation of 60%, the water production at the ultimate oil recovery was 3.7 cm^3, while for water-wet core it was 2.5 cm^3.

3.3. Effect of water saturation on oil recovery

3.3.1 Mixed-wet core

The effect of water saturation on the ultimate oil recovery from mixed-wet core appeared to be similar to that in water-wet core. Low water saturation was characterized by higher oil recovery, whereas high water saturation resulted in low oil recovery. Figure 2 shows the effect of different water saturation on

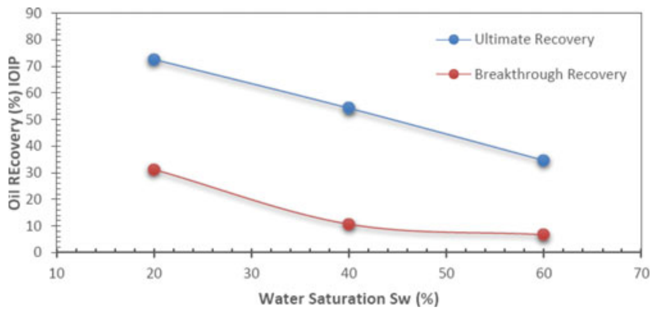

Figure 2. Effect of water saturation on the oil recovery for mixed-wet core.

the ultimate oil recovery for mixed-wet core. As observed from Figure 2, approximately 72.6% of the oil in place was recovered by gas flooding as a secondary recovery method at 20% water saturation. As water saturation increased from 20% to 40%, ultimate oil recovery has declined by 18.3%. The ultimate oil recovery at 40% water saturation was 54.3% of the oil initially in place. Further increase in water saturation resulted in gradual decline in the ultimate oil recovery. For instance, when the water saturation has been increased to 60%, the ultimate oil recovery declined to 34.6% of the IOIP. This result is consistent with those reported by Tang and Firoozabadi (2001).

3.3.2. Water-wet core

Figure 3 shows the results obtained from the gas flooding process conducted on water-wet Clashach sandstone core. The gas flooding was conducted at a gas flow rate of 0.2 cm^3/min on Clashach sandstone core with three different water saturation of 20%, 40%, and 60%. At 20% water saturation—where water is considered immobile—high oil recovery was obtained from the water-wet core. In this process gas was injected as a secondary recovery process. Figure 3 shows that the oil recovery at 20% water saturation was 61.1% of the oil initially in place. However, as water saturation increased to 40%, oil recovery decreased to 48.8%. Similarly, at high water saturation such as 60%, only 30.6% of the oil was recovered. A similar trend was observed by Zhou et al. (2000) in which breakthrough recoveries and final oil recovery by water flooding increased with decrease in water wetness.

3.4. Effect of wettability on the breakthrough time

The experimental study on water-wet and mixed-wet Clashach sandstone core with different water saturation shows that the wetting state of the core affects the breakthrough time for the gas injected. Figure 4 illustrates effect of wettability on the breakthrough time for mixed-wet and water-wet at three different water saturations. It is clearly shown that the breakthrough of nitrogen gas is faster in mixed-wet core than water-wet core. In water-wet core with 20% water saturation, the gas breakthrough time was 1.16 min whereas in mixed-wet core, the gas breakthrough time was 0.64 s. The results also have shown

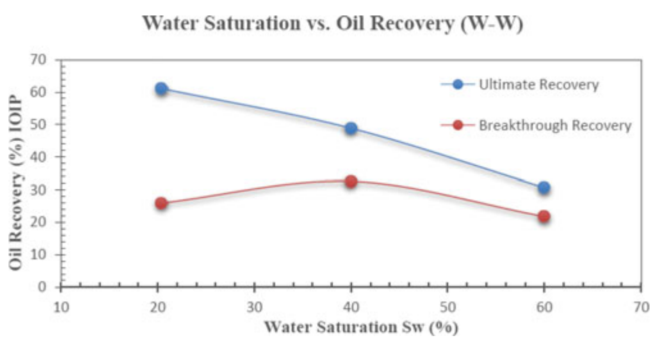

Figure 3. Oil recovery versus water saturation for water-wet core.

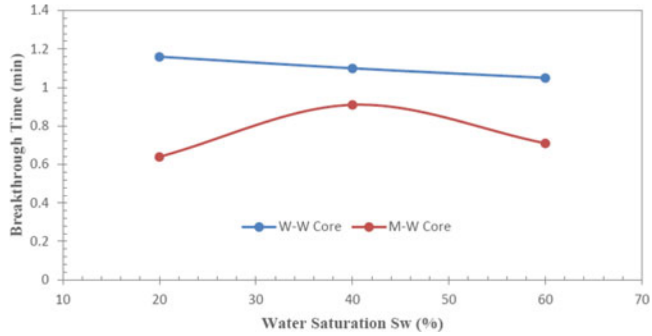

Figure 4. Two types of wettability states and its corresponding breakthrough time for three water saturations.

that, for all the water saturations used in these experiments, the breakthrough time for mixed-wet was less than that for water-wet cores. This observation is further supported by Valvatne and Blunt (2004).

4. Conclusion

The optimum wettability condition for this study that results in higher ultimate oil recovery was mixed-wet state compared with water-wet state. For instance, the ultimate oil recovery at 20% water saturation for mixed-wet core was 11.5% higher than that for water-wet core. Ultimate oil recovery for mixed-wet core was higher than that for water-wet core for all the three different water saturations. However, breakthrough recovery for water-wet core was higher than that for mixed-wet core. The effect of water saturation on the oil recovery for both water-wet and mixed-wet cores was almost the same. It was shown that as water saturation increases, the oil recovery decreases for both water-wet and mixed-wet cores.

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