Arabian Journal of Geosciences (2018) 11: 260
https://doi.org/10.1007/s12517-018-3611-6

ICCESEN 2017

Effect of water salinity and rock components on wettability alteration during low-salinity water flooding in carbonate rocks

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Received: 3 January 2018 / Accepted: 17 May 2018 / Published online: 30 May 2018

Abstract

In this paper, contact angle measurements using crude oil, five carbonate rocks, and six brines were conducted to study the effect of water salinity and rock components on wettability alteration. The results showed that lowering water salinity results in wettability alteration of carbonate surfaces to more water-wet. And there exists an optimal salinity at which the maximum wettability alteration occurs. In addition, the optimal salinity tends to increase as the content of dolomite in the rock decreases gradually. When low-salinity water is kept the same, the lower dolomite content in the carbonate rock, the more water-wet the rock will tend to be.

Keywords Low-salinity water · Contact angle · Salinity · Carbonate rock

Introduction

Water flooding has been widely applied to supply energy support and enhance hydrocarbon production as a secondary oil recovery method (Morrow and Buckley 2011; Shehata et al. 2014; He et al. 2017a). However, limitations of conventional water flooding make it hard to improve oil recovery during the late development period or some kinds of reservoirs due to the formation heterogeneity (e.g., vugs and fractures), rock wettability, and water breakthrough (Shehata et al. 2014; He et al. 2017b). Low-salinity water flooding (LSWF) becomes a preferred choice to further improve the oil production as the tertiary recovery (Al-Shalabi et al. 2013).

Low-salinity water denotes that the salinity of the injected water is lower than that of formation water, which is believed to below 5000 mg/L in order to obtain optimal displacement performance. During the last decade, several laboratory and field studies have shown that lowering the salinity of the injected brine can improve oil recovery in carbonate reservoirs in a favorable way (Mohsenzadeh et al. 2016). The incremental oil recovery has been mainly attributed to wettability alteration of carbonate surfaces via mechanisms such as change of surface charge (Zhang and Austad 2006), anhydrite (Austad et al. 2012), dissolution of calcite (Yousef et al. 2011), or a combination of them (Al-Shalabi et al. 2014; Bouguerra and Labbani 2014).

Although the effect of LSWF has been widely recognized, the underlying mechanisms are still being questionable. The discrepancy in observations and explanation among researchers for justifying the results may be a result of their specific cases and test conditions (Anderson 1986). The LSWF experiment results with specific mineral component carbonate rocks (marble, lithographic limestone, calcite plate, etc.) cannot represent all carbonates under LSWF, which is ignored by previous studies in general. Until now, more specific cases of alteration from oil-wet to water-wet conditions for LSWF remain poorly understood.

In this paper, we investigated the wettability alteration on different component carbonate rocks with brine of different salinities. The outcome of this work will improve the understanding of the effect of water salinity and rock components on wettability alteration during LSWF in a comprehensive and systematic manner.

This article is part of the Topical Collection on *Geo-Resources-Earth-Environmental Sciences*

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Table 1 Properties of rock samples

Formation	Brine permeability (mD)	Porosity (%)	Diameter (cm)	Length (cm)
Cambrian	0.05~0.1	1~2	2.54	7.5 ± 0.5

Table 2 Fractions of carbonate minerals estimated by X-ray diffraction analysis

Rock samples	Mineral concentration (%)			
	Quartz	Feldspar	Calcite	Dolomite
A	0	0	0	100
B	0	0	27.4	72.6
C	0	0	53.9	46.1
D	2.5	1	80.8	15.7
E	1.7	0	98.3	0

Experimental materials and methodology

Rock samples

The rocks were drilled from Xiaweidian Cambrian strata outcrop formation in Beijing, China. The properties of rock samples are shown in Table 1. X-ray powder diffraction (XRD) technique was used to determine the mineralogy of the rock samples, as shown in Table 2.

Crude oil

A crude oil sample was used in this study, which was selected from a carbonate reservoir system in the Middle East. The basic properties (measured at atmospheric pressure and room temperature) of the crude oil are listed in Table 3.

Brines

A variety of synthetic brines with different salinities were used in this study. They were prepared by dissolving reagent-grade salts with distilled water. Table 4 depicts the composition, concentrations, and properties of the brines. FW-20, FW-50, FW-100, FW-200, and FW-500 respectively represent diluting formation water (FW) with distilled water for 20, 50, 100, 200, and 500 times.

Methodology

In this study, the captive bubble method was utilized to measure the wetting angle of oil/water on carbonate rock surfaces. Figure 1 shows the schematic of captive bubble method measurement instrument for this study. Contact angle measurement was performed through the digital camera and computer every 5 h until the angle was no longer changed.

Table 3 Crude oil properties

Crude oil	Density (g/cm^3)	Viscosity (cp)	Asphaltene content (%wt)	Resin content (%wt)	TAN (mg KOH/g)	TBN (mg KOH/g)
ME	3.273	1.834	0.460	3.771	0.758	0.152

Table 4 Brine composition and concentration

	LSW-1 (FW)	LSW-2 (FW-20)	LSW-3 (FW-50)	LSW-4 (FW-100)	LSW-5 (FW-200)	LSW-6 (FW-500)
Na^+ (mg/L)	75,009.6	3750.5	1500.2	750.1	375.0	150.0
K^+ (mg/L)	1170.9	58.5	23.4	11.7	5.9	2.3
Ca^{2+} (mg/L)	13,626.8	681.3	272.5	136.3	68.1	27.3
Mg^{2+} (mg/L)	1748.0	87.4	35.0	17.5	8.7	3.5
Cl^- (mg/L)	145,134.9	7256.7	2902.7	1451.3	725.7	290.3
SO_4^{2-} (mg/L)	1116.7	55.8	22.3	11.2	5.6	2.2
HCO_3^- (mg/L)	422.7	21.1	8.5	4.2	2.1	0.8
TDS (mg/L)	238,460.5	11,923.0	4769.2	2384.6	1192.3	476.9
Ionic strength (mol/L)	4543.5	227.2	90.9	45.4	22.7	9.1

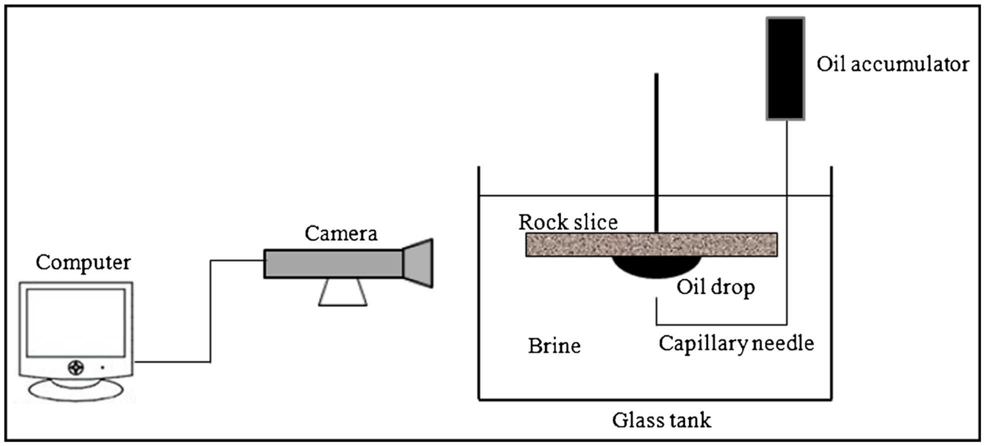

Fig. 1 Schematic of captive bubble method measurement instrument

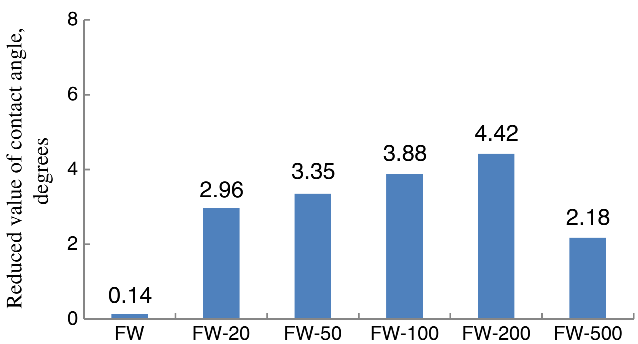

Fig. 2 Comparison on reduced value of contact angle for sample A in presence of each brine

Results and discussion

A total of 30 experiments were carried out in a rock/oil/brine system to measure the contact angles by using captive bubble method. The results show that the contact angles decrease in varying degrees when the rocks were in presence of low-salinity water. The maximum change of contact angle for samples A~E was compared under different conditions, as shown in Figs. 2, 3, 4, 5, and 6.

For sample A, the content of dolomite is 100%. Figure 2 indicates the contact angle changes when the rock was in presence of brines. The contact angle hardly changes when it was in presence of FW. Relatively obvious changes occur when the salinity is lowered. And with the decrease of salinity, the reduced value of contact angle increases first and then decreases. The maximum change of contact angle (4.42°) occurs when the brine is FW-200, whose salinity is 1192.3 mg/L. That is to say, for sample A, the effect of brine on the rock wettability is the strongest when the salinity of brine is about 1192.3 mg/L.

From sample A to E, the content of calcite in the rock increases while the content of dolomite decreases gradually. Figures 3, 4, 5, and 6 show the contact angle changes when the rocks of sample B to E were in presence of brines. We can clearly see that there are no appreciable changes in contact angle when the rocks were in presence of FW, just like sample A. And each sample has an optimum water salinity that altering rock wettability to more

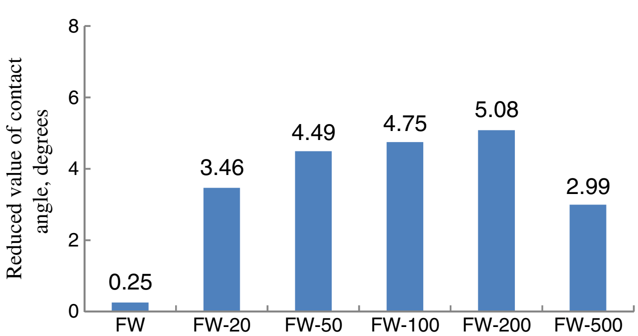

Fig. 3 Comparison on reduced value of contact angle for sample B in presence of each brine

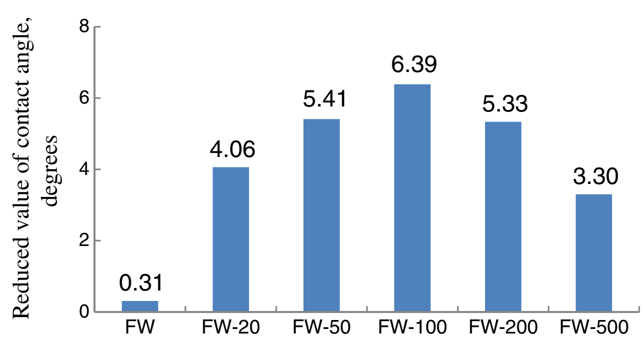

Fig. 4 Comparison on reduced value of contact angle for sample C in presence of each brine

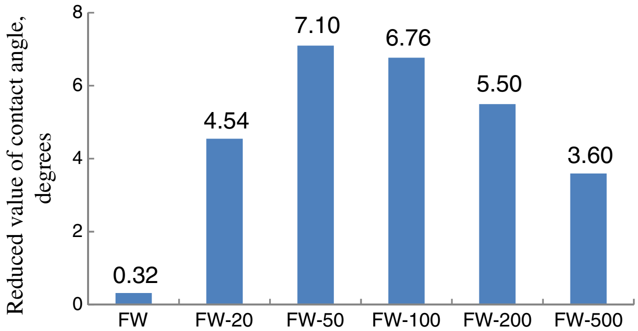

Fig. 5 Comparison on reduced value of contact angle for sample D in presence of each brine

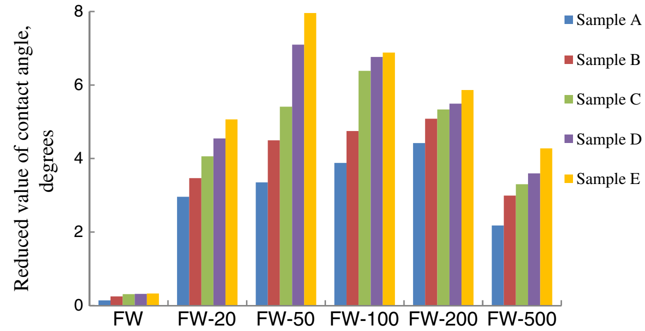

Fig. 7 Comparison on reduced value of contact angle for samples A~E in presence of each brine

water-wet. For samples B~E, the optimum salinity is 1192.3, 2384.6, 4769.2, and 4769.2 mg/L respectively. As it is, the salinity value, which maximizes the change of contact angle for samples A to E, tends to increase as the content of dolomite in the rock decreases gradually.

Figure 7 shows the comparison of the maximum change of contact angle among samples A to E in presence of each brine. It is obvious that when low-salinity water is kept the same, the change of contact angle is increasing from sample A to sample E. In other words, the lower dolomite content of the carbonate rocks, the greater change of contact angle. This phenomenon can be attributed to the different types and contents of cations on the surface of dolomite and calcite. The charge on the dolomite ($CaMg(CO_3)_2$) surface tends to be more positive than calcite ($CaCO_3$), which will cause a stronger adhesion between dolomite and oil. When it is in presence of saline, the oil on the dolomite surface is more difficult to be substituted. As a result, the lower dolomite content in the rock, the easier the oil be substituted by the ions (mainly Mg^{2+} and Ca^{2+}) in the brine, and then the more water-wet the rock will tend to be.

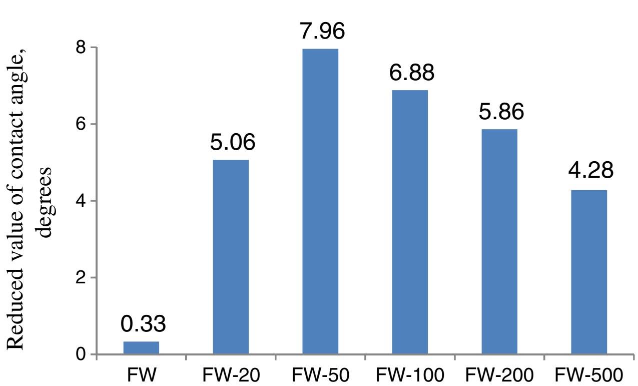

Fig. 6 Comparison on reduced value of contact angle for sample E in presence of each brine

Conclusions

Lowering salinity of the brine results in wettability alteration of carbonate surfaces to more water-wet. And there exists an optimal salinity at which the maximum wettability alteration occurs. In addition, the optimal salinity tends to increase as the content of dolomite in the rock decreases gradually. When low-salinity water is kept the same, the lower dolomite content in the carbonate rock, the more water-wet the rock will tend to be.

Funding information The study was financially supported by the National Natural Science Foundation Project(No. 51374222), the National Major Project(No. 2017ZX05032-004-002), the National Key Basic Research and Development Program(No. 2015CB2509005), and the Major Project of PetroChina(No. 2017E-0405).

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