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Experimental Analysis of Surface Tension Alteration by Salinity Change for Oil-Wet Rocks

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Abstract: Wettability of porous media is altered from preferential liquid-wetting to preferential gas-wetting. The present work is an insight that addresses the issue of wettability alteration by change in brine. Moreover, herein is presented the effect of reservoir water concentration on surface tension of oil. By means of contact angle measurements, a Berea sandstone core was saturated with crude oil and used as reservoir rock. Not only the spreading was found to be dependent of the contacting fluid properties, but also the surface tension increased significantly with the concentration in brine. Moreover, the spreading on the core, which to an extent accesses the performance of waterflooding, was seen to be altered by chemical composition of the brine.

Keywords: *Wettability; Surface tension; Salinity; Crude oil.*

1. Introduction

Waterflooding remains the preferred method to recover residual oils from an oil reservoir after the primary stage. The efficiency is reported to range from 10 - 20% of the original oil-in-place (OOIP) [1].Its principle relies upon the injection of fluid (water) in the depleted reservoir, which subsequently increases the volume of the oil. Injection of water develops within the reservoir interactions with the formation rocks including water-wet, oil-wet and mixed wet (Fig. 1). The matter is still matter of investigations [2]–[4]. When two immiscible liquids contact are a surface, the tendency of each to adhere or spread to the surface is known as wettability [2].

Wettability appears to be greatly affected by several factors including (1) reservoir rock formation, (2) water salinity and (3) type of crude oils. In immiscible state in the reservoir, oil and brine formed with grain a mixed wet system [6], which equilibrium depends primarily on the surface tension between each pair [7]. Each surface tension acts upon its respective interface and defines the angle θ at which the liquid contacts the surface [8], [9]. Anderson (1986) reported that wettability is dependent of the fluids distributions and is affected core analyses [2]. Also, extensive works have highlighted the effect of the brine on surface tension [7], [10]–[12]. In sandstone cores, ionic strength along with the acidity/alkalinity were found to alter formation permeability which subsequently influenced fine migration and drastic damage [13], [14]. Fines migration occurs when loosely attached particles are mobilized by fluid drag forces caused by the motion of fluid within the pore space. Also, Xu (2005) reported a dilution of reservoir brine increased the value of IFT compared to the original reservoir brine IFT result [15].

The aim of this paper is to give an insight of the mechanism occurring when reservoir water is contacted with an oil wet core. It highlights the effects of saline water concentration on surface tension; surface tension being a key factor to access oil recovery.

2. Materials and Methods

2.1. Materials

Oil - A dead heavy crude oil was used to saturate the core samples. With an API of 11.6, the crude oil has a specific gravity and kinematic viscosity of 0.988, 874 cSt at 15^{o}C and 30^{o}C.

Brines – The composition of synthetic formation water used in this study are listed in Table 1.

Porous medium - The core material is Berea sandstone core. 7 cm long with a diameter of 3.8 cm, this core has a porosity of 12% with permeability of 200 mD.

2.2. Methods

Core saturation – Using a clean core, a fluid saturation method described by Seil et al (1940) [16] was used in this work.

Spreading - Literature reports several methods to measure contact angle hysteresis, thus to compute interfacial tension (IFT). A simple test to determine contact angle (and thus wettability) is known as the sessile drop method. Among them, contact angle measurements using goniometer has gained prominence in oil industry [17], [15], [18], [19]. A drop of petroleum fluid, equal in size for each measurement (1-µl), was deposited on a virgin site of core. The spreading was recorded through a camera and the data were averaged for each surface–liquid combination. The experiments were carried out at ambient conditions.

3. Results and discussions

3.1. Physicochemical Parameters

Fig. 2 shows the spreading of different saline waters on oil wet rock. It could be seen a linear decrease over the contacting time. Similar observations were reported by Zekri et al. (2003) who found a decrease of the advancing angle while oil and water were contacted [20]. Such behavior may suggest that by altering the salinity of the reservoir during water injection, a change in contact angle is expected. The trend is thought to be associated to the free pore throats.

Fig. 3 illustrates the spreading rate of brine on an oil-wet core. On the same virgin surface, it could be seen an increase of the spreading with the salinity concentration beyond a concentration of 4wt. % NaCl. Below which, wetting phase spread faster at rate. The surface of the core behaves as if the addition of divalent ions inverted the trend. In fact, it is believed that ionic particles, to a certain degree, favored sandstone pore blocking [21]. Also, a possible chemistry involving the polar group of crude oil and the ionic water may explain plausibly wettability alteration [22]. Reservoir water, among the parameters that alter wettability [18], [3], [7], [12] was investigated in this study by the means of ionic strength which is defined as the measure of the concentration of dissolved chemical constituents in an aqueous solution. Obviously, the more concentrated is a solution, the higher the ionic strength. The surface tension was plotted then versus the aqueous ionic strength as shown in Fig. 4. The results of the experiment revealed that the concentration in salt of the injection water will increase the surface tension of the oil trapped within the pore of the cores. In other words, adding salt to water increases its ability to maintain its shape over water with no salt. Rao (2003) and Vijapurapu (2002) reported similar results. Therefrom, it was sought that water will only spread on the surface if and only if the surface tension falls below a critical value termed as critical spreading tension [23], [24].

4. Conclusions

Surface tension computed from contact angle measurements carried out on oil-wet core demonstrated that the surface tension alteration during waterflooding is a result of a series of physicochemistry mechanism occurring at the surface of the core. The concentration of reservoir water as well as the presence of divalent ions was found to react with polar group of the crude oil which subsequently alters the surface tension. Moreover, salinity and the ratio of divalent-to-monovalent ions by altering the polarity of crude oil were found promoted pore blocking.

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Table 1 *Composition of reservoir waters.*

Component	B1	B2	B3	B4
Sodium (Na+)	20	40	65	100
Calcium (Ca^{2+})	-	20	40	70
Magnesium (Mg^{2+})	-	-	10	50
Chloride (Cl^{-})	20	70	300	470

[a]*concentration are given in mg/l; TDS: Total Dissolved Solid.*

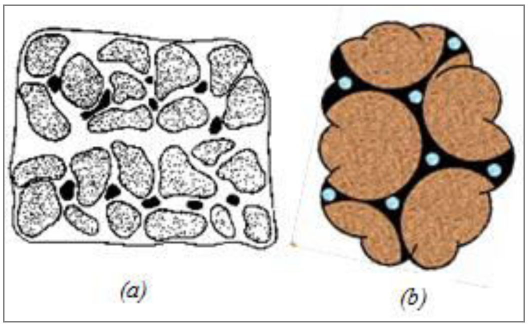

Fig.1. *Schematic of water-wet rock (a) and oil-wet core (b); Modified from reference* [5]

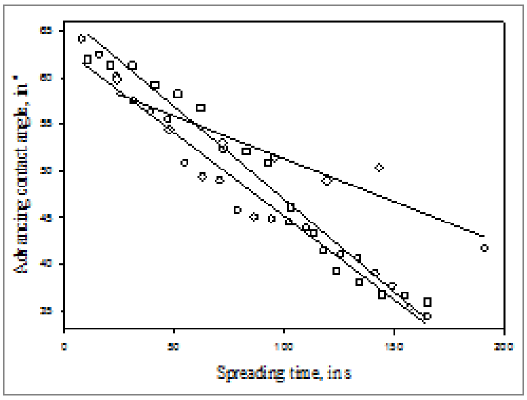

Fig.2. *Dynamic contact angles of different solution brines (○) B1; (□) B2; (◇) B4*

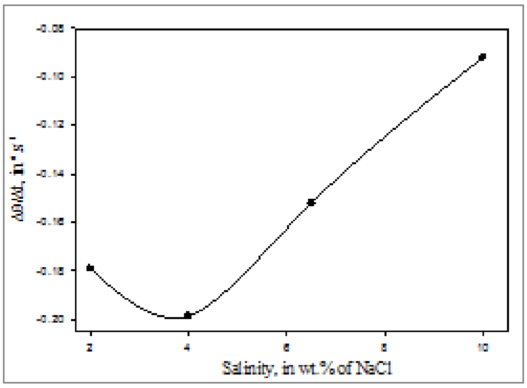

Fig.3. *Rate of change of spreading in respect of reservoir salinity*

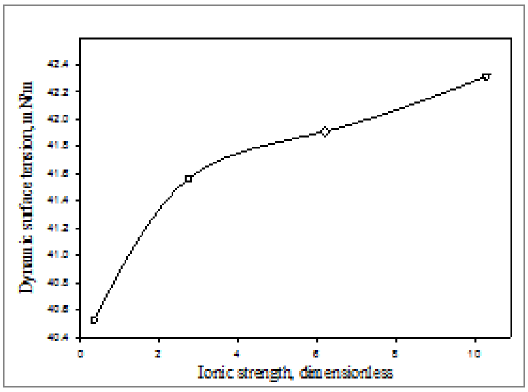

Fig.4. *Effect of water salinity on IFT (○) B1 (□) B2; (◇) B3; (▽) B4*