Journal of Petroleum Science and Engineering 169 (2018) 416–420

Contents lists available at ScienceDirect

Journal of Petroleum Science and Engineering

journal homepage: www.elsevier.com/locate/petrol

Effect of the rock dimension on surfactant imbibition rate in the Middle Member of Bakken: Creating a model for frac design

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ARTICLE INFO

Keywords:
Oil recovery
Cores
Length
Surface areas
Imbibition
Model
Frac design

ABSTRACT

As an unconventional energy resource, the Bakken Formation has long been considered an important source rock for oil in the Williston Basin. The naturally fractured Bakken Formation consists of thin shale and silty carbonate sequences, capable of producing oil at economic rates when completed using hydraulically fractured horizontal wells. However, because of its low permeability and oil-wet characters, the primary recovery values are still low.

As part of our effort to assess the potential for imbibition to recover oil from tight rocks, we performed spontaneous imbibition experiments using brine and surfactant for different dimensions of cores from the Middle Member of the Bakken Formation in North Dakota. The effect of length of the core on imbibition rate in the cores was measured for brine and surfactants. The purpose of this study is to create a model which can be basis for development of design of hydraulic fracturing of the formation. These cores from Bakken were silt stone, limestone, and shale interlayers in lithology. To the point of scaling the dimension of the core from laboratory to a field application, the large area of fluid contact will promote higher imbibition rate and faster oil recovery from the rock.

Although oil recovery was low during brine imbibition into the oil-wet cores, alkali/surfactant solution recovered approximately 30–45% of the oil based on the laboratory results. We found higher oil recovery factor was achieved from surfactant imbibition more than just used brine. As would be expected, a given level oil recovery was reached faster in shorter cores than in longer cores in same diameters. The shorter core has a larger ratio of surface area to volume. A model which describes the relationship between Peak Oil recovery and surface areas for cores was derived.

1. Introduction

A saline brine imbibed effectively into oil saturated Pierre cores yielding recovery values up to 41% OOIP (Wang et al., 2011a,b). Ten surfactant tests provided EOR values up to 25.40% OOIP in Bakken cores (Wang et al., 2012).

Spontaneous imbibition of water is the capillary suction of water by reservoir rock matrix and simultaneous expelling of the oil (Chilingar and Yen, 1983). This imbibition is only efficient in water-wet matrix blocks (Zhou et al., 1995). Treiber et al. (1972) and Chilingar and Yen (1983) show that most carbonate reservoir are mixed-to oil-wet. This makes the recovery from waterflooding of fractured carbonate reservoirs to be low. The process can be made more effective by diluting the solutions of surfactants which have been dissolved in the injected water and injecting into the reservoir with the target of changing the wettability of the reservoirs to a more water-wet state hence enhancing the spontaneous imbibition process and producing higher recovery of oil being released into the fracture network.

In recent years, chemical imbibition (using surfactant -brine formulations) is considered as a new method in enhanced oil recovery by improving displacement efficiency in ultra-low permeable tight rocks. The idea behind this method is to introduce diluted surfactant solution (0.1–25% in active concentration) to stimulate the recovery (Wang et al., 2011a,b, 2012). As part of investigations of aqueous liquid imbibition to stimulate oil recovery from shale, Wang et al. (2016) studied the recovery processes using an optimal surfactant formulation at reservoir conditions. The results show better oil recoveries using surfactant solutions.

Mirzaei and DiCarlo (2013) said that imbibition of surfactant solution into oil wet fractured cores is gravity dominated, the surfactant solution imbibes from the bottom and sides of the core, with higher imbibition close to the bottom of the core.

In this study, we performed spontaneous imbibition experiments using brine and surfactant for different dimensions of cores. The purpose of the study is to determine how different imbibition solutions affect oil recovery in Bakken formation and how the dimensions of the

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https://doi.org/10.1016/j.petrol.2018.05.075
Received 6 March 2018; Received in revised form 5 May 2018; Accepted 29 May 2018
Available online 01 June 2018

core i.e. lengths, surface area to volume ratio influence oil recovery in the formation.

2. Experimental

2.1. Spontaneous-imbibition experiments

2.1.1. Materials

2.1.1.1. Oil and brine. Cores were saturated with crude oil from the Bakken Formation of the Willinston Basin in North Dakota. The average API gravity of the Bakken crude was 42.48° in API, oil density was 0.82 g/cm^3, and oil viscosity was 4.2 cp at 25 °C There were four main cations (Na^+, K^+, Ca^{2+}, Mg^{2+}) present (as chlorides) in the Bakken brine. Beyond of the formation salinity of Bakken (20–30%), a total salinity of the brine water we used here was 10% by weight based on optimal salinity for surfactant imbibition (Wang et al., 2011a,b).

2.1.1.2. Surfactant. The surfactant used for preparation was an Alcohols Ethoxylated nonionic surfactant with 0.1% concentration.

2.1.1.3. Porous media. The rock plugs tested for spontaneous imbibition from the Middle Member of the Bakken Formation in North Dakota. Core samples are described as limestone, light gray color, fine grained in lithology. Table 1 shows the permeability and porosity values for the core samples (NDIC, 2013.).

The dimensions of the cores in experiments is shown in Table 1.

There are two sets of cores used for surfactant and brine spontaneous imbibition tests. Cores in native status (cores 1–57 and 1–59), never had chemical treatment before oil saturation. The average initial water saturation of these native cores was 62.5% and 33.6% respectively (NDIC, 2013).

Cores labelled 1–61 and 1–68 were cut into 10 mm and 20 mm, approximately respectively. The core 1–61 was used for brine imbibition, while the core 1–68 was used for surfactant imbibition. The cores 1–57 and 1–68 were used as supplied with average length of 40 mm approximately for each. All the cores were argillaceous limestone, dense with no visible porosity (NDIC, 2013).

2.2. Experimental procedure

Two set of experiments was carried out. In the first set, cores of 1–61 and 1–68 (all cleaned) and 1–57 and 1–59 (both native cores) were used. Cores of 1–61 and 1–68 were cleaned with toluene, methanol for 48 h. The Dean stark equipment was used to clean the cores. The cores were then dried in oven at temperature of 105 °C for 24 h.

They were placed in vacuum bottles connected to a vacuum pump, and vacuumed for 2 h to remove entrapped gases. The initial water saturation for these cores was zero.

For the second set cores, no chemical treatment before oil saturation.

2.2.1. Oil saturation

The cores for oil saturation were weighed and measured values recorded. An ISCO Model 100DX syringe pump which has low flow rate capability was used to oil saturation. The distilled water was pumped into the ISCO pump first with a flow rate of 500 ml/h, we then ran the distilled water from a pump into a transfer cylinder with the same flow rate. Crude oil was pumped into the transferred cylinder. (The oil occupied the upper part, whereas the water stays in the lower part of the cylinder. The approximate volume of the cylinder is 250 cm^3 capacity).

The cores were put in Hassler's cell with injection pressure of about 800 psi and confining pressure of 1500 psi. The pressure changes were recorded.

After oil saturation, spontaneous imbibition experiments were conducted in the same time. Table 2 shows the cores used and imbibition solution in each of the two experiments. Six cores of approximate lengths of 10 mm in brine imbibition, 15 mm in brine imbibition, 40 mm in brine imbibition; 10 mm in surfactant imbibition, 19.518 mm in surfactant imbibition, 40 mm in surfactant imbibition) for 9 days, at 115 °C.

In the second experiment, the three cores of 1–61-A and 1–61-B were re-cleaned, re-vacuumed and oven dried, and re-saturated. These two cores in addition to core 1–61-C were used to imbibe oil with same surfactant, then the steps as described above were repeated.

In the spontaneous imbibition, the imbibition cells (Amott Cells) were immersed in a temperature bath at 115 °C. This is shown in Fig. 1. The cells were filled with a volume of aqueous solution of either surfactant or brine, then we put them in a temperature bath at reservoir temperature for 9 days to displace oil until oil production stopped. The oil rate and percent of OOIP oil recovery was calculated using volume of oil expelled. The pH of brine and surfactant solution was ranged from 6.7 to 6.76.

Table 2
Cores and Imbibition solution.

s/no	Cores	Cores	L (mm)	D (mm)	Area/ Vol. Ratio	Imbibition solution	
						First Experiment	Second Experiment
1.	1–61	1–61-A	12.945	38.093	0.07725	Brine	Surfactant
2.		1–61-B	11.673	38.208	0.085668	Surfactant	Surfactant
3.		1–61-C	10.938	38.045	0.091424		Surfactant
4.	1–68	1–68-A	15.985	38.075	0.062559	Brine	
5.		1–68-B	19.518	37.961	0.051235	Surfactant	
6.	1–57	1–57	40.610	38.100	0.024624	Brine	
7.	1–59	1–59	40.030	38.200	0.024981	Surfactant	

3. Results analysis and discussion

Fig. 2 shows the recovery of oil with time for cores of 1–61 with brine and surfactant solutions.

The peak oil recovery factor was reached at almost the same time for both solutions, but the peak for the base brine with surfactant solution was the highest. Wang et al. (2011a,b) reported similar observation in their experiment on surfactant formulation study for Bakken Shale Imbibition.

Fig. 3 shows oil recovery of cores of 1–68 with base brine and surfactant solution.

Table 1
The dimensions of the cores in different experiments is shown in Table 1.

s./no	Cores	Cores	L (mm)	D (mm)	Area/Vol. Ratio	Porosity (%)	Permeability (md)
1.	1–61	1–61-A	12.945	38.093	0.07725	7.1	0.072
2.		1–61-B	11.673	38.208	0.085668		
3.		1–61-C	10.938	38.045	0.091424		
4.	1–68	1–68-A	15.985	38.075	0.062559	2.4	0.084
5.		1–68-B	19.518	37.961	0.051235		
6.	1–57	1–57	40.610	38.100	0.024624	0.0014	6.3
7.	1–59	1–59	40.030	38.200	0.024981	0.017	3.3