Petroleum 5 (2019) 123–127

Contents lists available at ScienceDirect

Petroleum

journal homepage: www.keaipublishing.com/en/journals/petlm

Application of Lauryl Betaine in enhanced oil recovery: A comparative study in micromodel

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ARTICLE INFO

Article history:
Received 24 July 2017
Received in revised form
3 September 2017
Accepted 6 September 2017

ABSTRACT

Micromodel flooding is a cost-effective method to investigate enhanced oil recovery. In this study, we apply Lauryl Betaine as an amphoteric surfactant to the injected fluids into the micromodel and compare the results with conventional EOR techniques such as water flooding, solvent flooding, and micro-emulsion flooding. First, we determined the optimal flow rate of injected fluid into the micromodel to represent fluid flow in the formation. Next, we did water flooding with varying salinities. Next, we did solvent flooding with two different ratios of solvents. Condensate and hexane are the solvents we applied. Next, we did surfactant flooding using Lauryl Betaine. Surfactant flooding tests are conducted using different salinity and surfactant concentration (C_s). Finally, we did microemulsion flooding. The results show that surfactant flooding at high salinity using Lauryl Betaine leads to highest oil recovery among all tested EOR methods. Besides, the results indicate that addition of Lauryl Betaine to the injected brine leads to higher breakthrough time (BT).

1. Introduction

Enhanced oil recovery is the center focus of energy industry to improve recovery factors (RF) for hydrocarbon productions at field scales [1]. Production decline from the wells has lead researchers to develop more efficient enhanced oil recovery methods in conventional and unconventional reserves [2,3]. Researchers have developed different numerical and experimental approaches to study various pore-level physics with regards to multiphase fluid flow in porous media [4,5]. Since early stages of oil discovery and production, water injection into injection wells was used to maintain pressure and enhance production from producing wells [6]. Availability of water resources, high-performance water pumps and modest sweep efficiency has made water flooding a cost effective technique for increasing oil recovery in secondary oil recovery from zones of interest [7]. Improving sweep efficiency is one of the methods to enhance oil recovery through water flooding [8]. Adding chemicals such as surfactants and polymers to injecting fluid is one of the current methods to achieve higher sweep efficiency in water flooding [9].

There are different types of surfactants: ionic, non-ionic and amphoteric. This variety of surfactants originate from particular structure of surfactants which has a polar component and a nonpolar component. The polar component is either ionic or nonionic [10]. The polar component is called the head, and the nonpolar part which is a hydrocarbon chain is known as the chain of the surfactant [11]. The head tends to be solubilized in aqueous solvents such as brine and the chain in organic solvents such as oil. Hence surfactants stabilize in the interface between oil and brine [12]. Such placement of surfactant in between two phases is called solubilization and lowers the interfacial tension between oil and brine [13–15]. Introducing surfactants into immiscible organic-aqueous mixture leads to the formation of micro emulsion [16]. Unlike emulsion mixtures, micro emulsions are homogeneous mixtures and are thermodynamically stable. Formation of the micro emulsion is highly advantageous in water flooding since the micro emulsion lowers the interfacial tension between oil and

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Peer review under responsibility of Southwest Petroleum University.

Production and Hosting by Elsevier on behalf of KeAi

http://dx.doi.org/10.1016/j.petlm.2017.09.004

water and leads to higher mobility ratio [17]. Numerous parameters affect reaching a stable micro emulsion in a water-oil-surfactant solution. Surfactant type, salinity of the brine, oil type and operating pressure and temperature impact stability of the solution [18]. Optimizing the operation parameters can lead to the formation of a heterogeneous stable micro emulsion which ultimately results in lowering interfacial tension in the oil-brine-surfactant mixture and finally reaching higher oil recovery by brine-surfactant flooding [19].

Micromodels have been widely used in laboratory settings to mimic flow and oil recovery under certain operating conditions and design parameters in porous media [20–23]. Furthermore, micromodels provide a robust bed frame for visualizing sweeping of oil by injecting fluid [24]. By knowing the dimensions of the micromodel and through image processing techniques, relevant relative permeability curves under different saturations can be calculated [25]. Flexibility in a design of micromodel parameters such as injection/production layouts, scaling injection and production data and running sensitivity analysis under different operating conditions makes them unique to investigate a broad array of experiments to find out the most optimum set of parameters to achieve highest oil recovery. Numerous enhanced oil recovery techniques have been tested on glass micromodels. Nanoparticle flooding [26], alkaline flooding [27,28] and polymer flooding [29–31] experiments have been tested on glass micromodels.

EOR techniques have been tested on micromodels to find out most optimum parameters to enhance oil recovery. The role of cationic surfactant injection to increase oil recovery has been investigated [32]. Flooding micromodels with fractures embedded in them showed higher oil recovery compared with intact micromodels [33]. Further tests with micro emulsion flooding of micromodels showed the increase in oil recovery factor [34]. Also, controlling parameters such as temperature, salinity, and alkalinity of the injected fluids affect oil recovery from the micromodels [34]. In other studies, a mixture of cationic and non-ionic solutions was tested on high saline solutions to improve oil recovery from micromodels [35].

In this work, we introduce a novel amphoteric surfactant solution and conduct comparative EOR tests to investigate the efficiency of the surfactant solution to enhance oil recovery from micromodel. Water flood, polymer flood, surfactant flood and micro emulsion flood are among the applied techniques on the prepared micromodel. Oil recovery and breakthrough times are continuously measured and periodically visualized and recorded. Furthermore, we investigate the role of varying salinity of injected synthesized surfactant solutions on oil recovery.

2. Materials

We used reservoir oil to saturate. Oil properties are listed in Table 1. We used NaCl to prepare the brine. NaCl was purchased by Merck Co, Germany. Lauryl betaine is used as the amphoteric surfactant. Table 2 presents the physical and chemical properties of the materials used in this work, Table 3 shows the specifications of the amphoteric surfactant, and Fig. 1 demonstrates the chemical formula of Lauryl betaine.

Table 1
Sample oil properties.

Bubbe point pressure (psia)	API	Viscosiy (cP)	Dead oil viscoisty (cP)
2124.8	41.7	0.573	4.73

2.1. Micromodel preparation

To prepare a micromodel from the formation core plugs, we use Corel draw software to etch the pore network pattern of the plugs onto a glass sheet with a laser beam. The pore-network pattern obtained from thin section is designed using Corel draw software. A second glass is attached on top of the etched glass to create pore-network channels. The micromodel is then placed in an oven with programmed temperature control. The oven is cooled down from 700 0 °C down to room temperature. Two inlet and outlet holes are drilled into the micromodel to inject fluid and recover oil from the micromodel, respectively. Fig. 2 shows the micromodel pattern and Table 4 lists the petro physical characteristics of the micromodel. The experimental setup is composed of micromodel, quizix pump, light source, digital camera, image processor and a fluid collector as shown in Fig. 3.

To saturate and inject fluid into the micromodel, we use precise low-injection-rate Quizix pump (10–5 and 10–2 cm^3/min). Sudan red is added to the reservoir oil to distinguish the injected fluid from oil. We use an Eldex pump with three cleaning fluids: water, toluene and alcohol to clean the micromodel after finishing each step and before starting next stage of experiments. We conduct all experiments with the micromodel placed horizontally to neglect the effect of gravity.

2.2. Critical micelle concentration (CMC)

To find out the critical micelle concentration (CMC) of the selected surfactant, we synthesize aqueous surfactant solutions with varying surfactant concentrations ranging from 100 to 1000 ppm. Surface tension of each synthesized solution is measured using a tensiometer (model Kruss K10) through a ring method at 25 °C. The temperature is kept constant using a thermostatic bath. All experiments are conducted five times, and their mean values are selected. Fig. 4 shows the surface tension versus concentration for an aqueous solutions of Lauryl betaine. Surface tension of the synthesized solutions reach constant at critical micelle concentration. CMC for Lauryl betaine is 320 ppm.

3. Results and discussions

3.1. Optimum flow rate

Before doing micromodel flood tests, we need to find the optimum flow rate of the injecting fluid. First, we saturate the micromodel, and then we inject water at different flow rates. Oil recovery factor at the breakthrough time and oil recovery at one pore volume of injected fluid for three different rates of injected fluid are presented in Table 5.

According to the results at lower flow rates, oil displacement is slower. At higher flow rates due to fingering phenomena oil recovery lowers as well. Since we need to choose one flow rate for all injecting fluids, we choose test number 2 to be the optimum flow rate.

According to Table 5, 0.0008 cc/min is the optimum value. We apply this flow rate in all flooding tests. This rate is a representative rate of fluid flow in the zone of interest. Furthermore, injecting fluids at this rate reduces fingering and lowers the final oil residue in the micromodel post flooding.

3.2. Role of salinity of water

To investigate the role of water salinity on water flood efficiency, we run three waterflood tests at different salt concentrations. First, we saturate the micromodel with reservoir oil. Next, we inject

Table 2
Physical and chemical properties of material.

Material	Source	Formula	Initial Purity	Molecular Weight (g/mol)	Purification Method
Sodium Chloride	Merck	NaCl	>99.5%	58.44	None
Sudan black	Merck	C29H24N6	~99%	456.55	None
Toluene	Merck	$C_6H_5CH_3$	>99%	92.14	None

Table 3
Physical and chemical properties of Lauryl Betaine.

Surfactant characteristics	Amount
Molecular weight (g/mole)	271.44
Ionic nature	Amphoteric
Appearance	Yellow
Form	Liquid

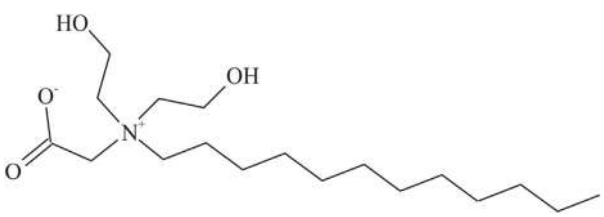

Fig. 1. Chemical formula of lauryl betaine.

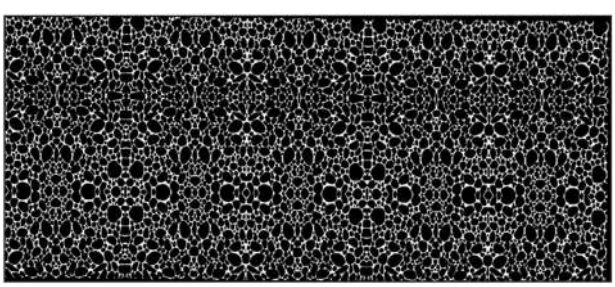

Fig. 2. Schematic of glass micromodel pattern.

water with different salt concentrations while keeping flow rate of injecting water at 0.0008 cc/min. We add Sudan Red to the brine to distinguish oil and brine. Table 6 shows the results. Recovery factor at break-through time (BT) is defined as the percentage of recovered oil in micromodel when the first droplet of injected fluid is recovered. RF at 1 pore volume (PV) is defined as the percentage of recovered oil after injection of enough injected fluid equivalent to the total pore volume of the micromodel. According to the results increasing the salinity of the injecting water leads to higher oil recovery from the micromodel. The reason is that higher salt concentration leads to higher brine viscosity. The Higher viscosity of injecting fluid leads to higher displacement of initial saturated oil and subsequently higher oil recovery from micromodel higher viscosity of the solution with highest salt concentration leads to a higher breakthrough time of injecting fluid. Table 5 shows breakthrough time of fresh water and brine with three different salinities.

Table 4
Physical and Hydraulic characteristics of glass micromodel.

Pattern Characteristic	Amount
Length (cm)	11
Width (cm)	3
Average depth (cm)	0.006
Pore Volume (cm3)	0.117
Porosity (%)	0.37
Absolute Permeability (D)	2.47

3.3. Role of solvent

In this section, we investigate a role of adding co-solvent to the injecting solvent during the solvent flooding of the micromodel. We mix the two solvents, hexane and condensate with different weight percentages. First, we synthesize a solvent with 30 wt% hexane and 70 wt% condensate. Next, we synthesize the second solvent with 70 wt% hexane and 30 wt% condensate. We inject the two solvents into the micromodel in two different runs. We keep the flow rate of the injecting solvent at 0.0008 cc/min. Table 7 shows that oil recovery from solvent flooding of the two tests is similar to each other. The results indicate that adding solvents to the micromodel does not affect the oil recovery factor. This can be the result of high API of the initial saturated oil of the micromodel.

3.4. Surfactant flooding

In this section, we investigate the role of the surfactant and their concentrations on oil recovery from the micromodel. We tested amphoteric surfactant.

3.4.1. Type of surfactant

First, we make three brine solutions 0, 5 and 10 wt% respectively. Next, we add a surfactant to the brine solutions to investigate the role of surfactant concentration in the injected fluid on oil recovery from the micromodel. Three surfactant concentrations of 0.3, 0.5 and 0.8 wt% are added to each brine solution. Overall, 9 solutions with varying salinity and surfactant concentrations are synthesized for each selected surfactant.

Overall we run 9 tests. For each test, we inject the synthesized solutions into the oil saturated micromodel. Breakthrough time, oil recovery factor at the breakthrough time are presented in Table 8. According to the results, increasing surfactant concentration leads to higher oil recovery and subsequently higher breakthrough time from the micromodel. This is due to lower interfacial tension of the solutions with higher surfactant concentration. Furthermore, the results indicate that increasing salinity of the injected solution into the micromodel leads to higher oil recovery and higher breakthrough time from the micromodel. Table 8 presents the experimental results of Lauryl betaine flooding. Figs. 5 and 6 shows the micromodel pattern after and before surfactant flooding.

3.5. Microemulsion flooding

In this section we investigate role of microemulsion injection on oil recovery from the micromodel.

3.5.1. Type of microemulsion

Adding surfactants into oil-water mixtures lead to formation of the microemulsion phase. Microemulsion phase is stable and can

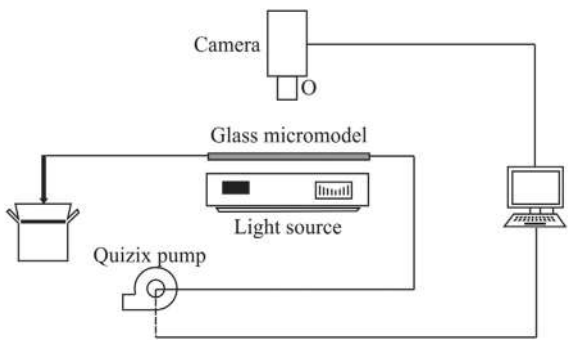

Fig. 3. Experimental procedure for Micromodel flooding.

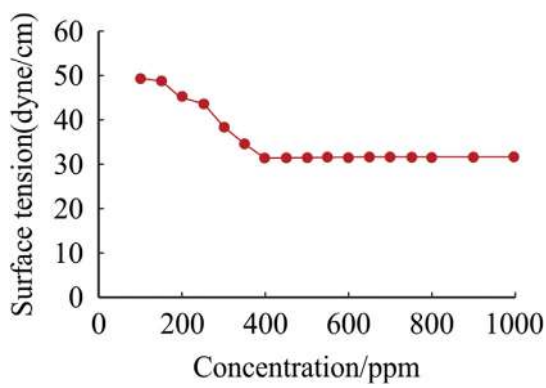

Fig. 4. Critical micelle concentration.

Table 5
Role of fluid flowrate on oil recovery factor.

Test No.	T(°C)	Q(cc/min)	BT(sec)	RF at BT	RF at 1 PV
1	25	0.0006	2462	37.3	37.8
2	25	0.0008	1686	27.6	28.1
3	25	0.0001	1087	19.2	19.8

be separated mechanically from oil and water phase. We separate the microemulsion phase of the two tested surfactants from the previous phase and inject them into the oil saturated micromodel. We keep the injection rate constant at 0.0008 cc/min. Table 9 shows the results from microemulsion injection into the micromodel. According to the results, amphoteric microemulsion leads to higher oil recovery and higher breakthrough time due to lower interfacial tension.

Table 6
Role of salinity concentration on oil recovery factor.

Test No.	T(°C)	Brine(ppm)	BT(sec)	RF at BT
4	25	1000	1743	28.3
5	25	10000	1862	32.1
6	25	100000	2038	34.8

Table 7
Role of type of solvent on oil recovery factor.

Test No.	T(°C)	Solvent Type	BT(sec)	RF at BT	RF at 1 PV
7	25	1	1320	57.3	58.2
8	25	2	3300	59.4	59.8

Table 8
Role of surfactant concentration.

Test No.	T(°C)	Cs Wt %	Salinity Wt%	BT (min)	RF at BT	RF at 1 PV
9	25	0.3	0	1927	30.16	32.10
10	25	0.5	0	2162	35.21	37.95
11	25	0.8	0	2345	39.64	41.83
12	25	0.3	5	2284	42.18	44.35
13	25	0.5	5	2468	45.37	47.29
14	25	0.8	5	2642	49.61	50.25
15	25	0.3	10	2403	50.61	53.81
16	25	0.5	10	3127	54.71	57.32
17	25	0.8	10	3487	64.41	68.49

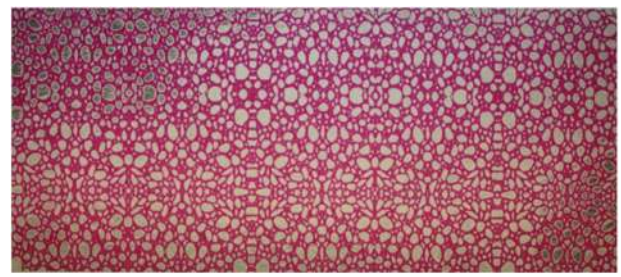

Fig. 5. Oil Saturated Micro model.

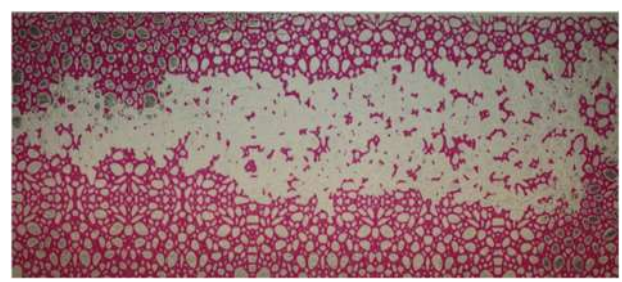

Fig. 6. Micro model after surfactant flooding.

4. Conclusions

In this paper, we investigated the role of Lauryl Betaine in enhanced oil recovery from micromodel. The glassy micromodel is designed and built based on a thin section from core plugs of the formation. The micromodel is saturated with reservoir oil and flooded with brine, solvent, surfactant, and microemulsion, respectively. Before do flooding, the optimal flow rate of the injected fluid is measured as 0.0008 cc/min to represent fluid flow in the reservoir. Water flooding results indicate that increasing salinity leads to the higher breakthrough time of injected brine and higher oil recovery from the micromodel. Solvent flooding results indicate oil recovery from the micromodel does not vary significantly by changing the ratio of the injected blend of solvents. Surfactant flooding results indicate that higher Lauryl betaine concentration in the injected brine leads to the higher breakthrough time of injected fluid and higher oil recovery from the

Table 9
Role of microemuslion flooding on oil recovery factor.

Test No.	T(°C)	BT(min)	RF at BT	RF at 1 PV
18	25	2853	51.81	54.62

micromodel. This is due to low interfacial tension between oil and injected fluid at higher surfactant concentrations. Finally, microemulsion flooding results show higher oil recovery compared with water flooding and solvent flooding and lower compared with surfactant flooding. Overall, the results indicate that surfactant flooding using high Lauryl Betaine concentration at high salinity leads to the highest oil recovery among all tested methods.

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