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Experimental Improvement of Nano-Enhanced Oil Recovery Using Nano-Emulsions

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Abstract Water injection is used for increasing the recovery factor as well as the reservoir's life time. Although this method improves the production efficiency, however, its performance has been enhanced using some procedures. One of these methods is surfactant injection into the oil reservoirs by the water injection process. In this study, the flow rate of the produced oil was improved by injection of amphoteric surfactant (coco amido propyl betaine) at different concentrations (1,000, 2,500, 5,000 and 7,500 ppm). Next, the morphology of water and surfactant was screened on the sand-packed matrix using spiral CT-scanner. According to that CT images, the in situ phenomena during water or surfactant injection were captured. The FTIR-ATR tests were performed on the samples of the process of water and surfactant injection. The experimental results revealed that the injection of the above-mentioned surfactant (at concentration of 1,000 ppm) increased the recovery factor up to 40 %. Likewise, the injection of the above-mentioned amphoteric surfactant reduced the interfacial tension of oil and reservoir's rock, leading to more oil recovery. The extraction time was increased in the presence of the above-mentioned surfactant owing to the postponed stage of water breakthrough. The above-mentioned surfactant in the process of water injection improved the oil production from the sand-packed matrix.

Keywords Nano-enhanced oil recovery · Water flooding · Surfactant · Amphoter

الخلاصة

يستخدم حقن الماء لزيادة معامل الاستخلاص ، ووقت حياة الخزان. وعلى الرغم من أن هذه الطريقة تحسن كفاءة الإنتاج، إلا أنه تم تعزيز أدائها باستخدام بعض الإجراءات. وإحدى هذه الطرق هي حقن مواد فعالة سطحيا في خزانات النفط بوساطة عملية حقن الماء. وفي هذه الدراسة، تم تحسين معدل التدفق من النفط المنتج عن طريق حقن مادة فعالة سطحيا مذبذبة الشحنة (كوكو أميدو بروبيل البيتين) بتراكيز مختلفة (1000 ، 2500 ، 5000 و 7500 جزء في المليون). وتم بعد ذلك فحص مورفولوجية الماء والمادة الفعالة سطحيا على مصفوفة رمال معبأة باستخدام ماسحة التصوير المقطعي الضوئي المحوسبة واللولبية. ووفقا للصور المقطعية، فقد تم التقاط الظواهر المكانية خلال حقن الماء أو المادة الفعالة سطحيا. وأجريت الاختبارات مطيافية الأشعة تحت الحمراء المعالجة بفوريه ـ الانعكاس الكلي الموهن على عينات من عملية حقن الماء والمادة الفعالة سطحيا. وأظهرت النتائج التجريبية أن حقن المادة الفعالة سطحيا المذكورة أعلاه (بتركيز 1000 جزء في المليون) يزيد من معامل الاستخلاص بنسبة تصل إلى 40 ٪. وبالمثل، فإن حقن المادة الفعالة سطحيا مذبذبة الشحنة المذكورة أعلاه يؤدي إلى خفض التوتر البيني للنفط وصخور الخزان، مما يؤدي إلى المزيد من استخراج النفط. وازداد وقت الاستخراج في وجود المادة الفعالة سطحيا المذكورة أعلاه نظرا للمرحلة المؤجلة من اختراق الماء. وحسنت المادة الفعالة سطحيا المذكورة أعلاه في عملية حقن الماء من إنتاج النفط من مصفوفة الرمال المعبأة.

1 Introduction

Improvement of oil recovery from crude oil reservoirs has always been an important issue because it helps to meet ever growing energy demand. The capabilities in nanotechnology are rapidly expanding in many fields such as enhanced oil recovery (EOR). Enhanced recovery processes for crude oil are mainly including miscible and immiscible gas injection (for light oil reservoirs): thermal, solvent-based and cold methods (for heavy oil reservoirs). In thermal methods such as steam-assisted gravity drainage (SAGD), combustion overhead gravity drainage (COGD), cyclic steam stimulation (CSS) and in situ combustion (ISC) or toe-to-heel air injec-

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tion (THAI), the viscosity is reduced by heating the reservoir, but the major problem is the heat loss into the adjacent formations [1].

Water flooding is one of the most economical methods to increase the oil recovery [2]. It was first practiced for the pressure maintenance of reservoirs after primary depletion and has since become the most widely adopted improved oil recovery (IOR) technique [3]. Water injection is known as a secondary recovery in order to maintain reservoir pressure; however, water injection in combination with other substances (in order to sweeping the oil bank) is known as a tertiary recovery method. Chemical flooding is a general term for injection processes that uses special chemical solutions. Micellar, alkaline and soap-like substances are used to reduce the surface tension between oil and water phases in the reservoir, whereas polymers (such as polyacrylamide or polysaccharide) are employed to improve the sweeping efficiency. The chemical solutions are pumped through specially distributed injection wells to mobilize the oil left behind after the primary or the secondary recovery. Chemical flooding is a major component of EOR processes and is subdivided into micellar–polymer flooding, alkaline flooding and surfactant flooding. The surfactant reduces the interfacial tension (IFT) between the brine and the residual oil, and therefore, it increases the capillary number [4]. The surfactant-based chemical flooding processes are normally employed to recover the trapped, residual oil after the water flooding [5].

Recently, a lot of flooding systems, especially surfactant-enhanced alkaline systems, have been reported [6–9]. Surfactant flooding (such as tertiary oil recovery) has been employed for more than 35 years. The proper surfactant formulation and its controlled flow lead to achieve the maximum oil recovery [10].

Gogoi et al. [11] studied the effect of didodecyl dimethyl ammonium bromide (DDAB) and sodium ligno suffocate (SLS) surfactants on the recovery factor. Thigpen et al. [12] added surfactant in the alkaline solution to reduce the oil/water interfacial tension. Rudin et al. [13] investigated the effect of added surfactant on the interfacial tension and spontaneous emulsification in alkali and acidic oil systems. Many papers have focused on the study of interfacial tensions between surfactant systems and crude oils [14,15]. One factor that has been known to degrade the oil recovery is the preferential channeling of flow largely caused by viscosity- driven instability and variable permeability (heterogeneity). Viscosity-driven instability, also known as the Saffman-Taylor instability, is the cause of what is known as the fingering phenomenon, which leads to early breakthrough, thereby degrading oil recovery even in homogeneous reservoirs [16]. Li et al. [17] studied the effect of anionic surfactant sodium oleate (NaOA) solutions in the presence of sodium phosphate (Na_3PO_4) on the oil recovery factor. Jennings et al. [18] performed caustic flooding core flood tests on preserved core samples using heavy oil. Okandan conducted core flood tests by injecting surfactant slugs [19]. Alkaline/surfactant/polymer (A/S/P) flooding technology, as an important technology of tertiary oil extraction, has been found to enhance the oil recovery more than 20 % and hence, it has been used thoroughly in the Daqing oil field [20]. Standnes proved that cationic surfactants have higher efficiencies than anionic surfactants [21]. Batanoneney et al. [22] studied the effect of surfactant mixtures. Asphaltenes are classified as another class of natural surfactants [23].

In this paper, the effect of surfactant (coco amido propyl betaine) injection was investigated at different concentrations (1,000, 2,500, 5,000 and 7,500 ppm). They create nano-size aggregates such as nano-emulsions. The optimum concentrations were determined, and it was revealed that the maximum produced oil achieved at 1,000 ppm of surfactant.

2 Experimental Method

In this study, five experiments were conducted, the first was the water injection and the four others were the surfactant injection with different concentrations (1,000, 2,500, 5,000 and 7,500 ppm). All of the experiments were conducted at the same reservoir's conditions including porosity (35 %), permeability (15–18 D), etc.

2.1 Materials and Tools

The flow diagram of the setup is schematically illustrated in Fig. 1. The core holder was a three-dimensional cylindrical

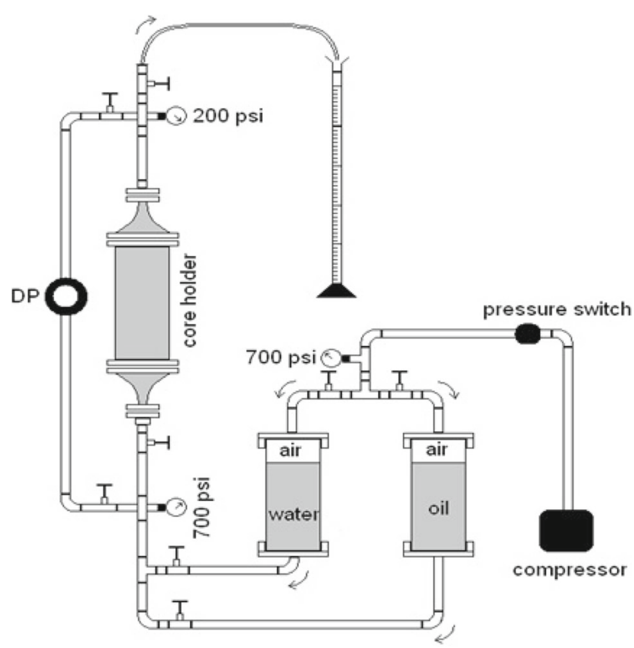


Fig. 1 Flow diagram of the setup

Table 1 Physical and chemical properties of CAPB

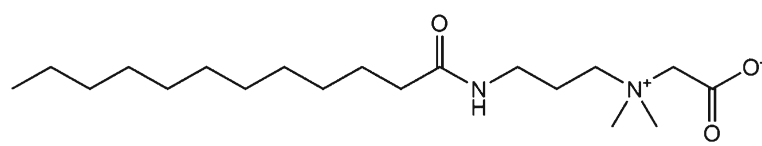
Characters	Amounts
Molecular weight (g/mole)	342.52
Ionic nature	Amphoteric surfactant
Appearance and form	Light yellow, liquid
Bubble point (°C)	600–700
pH (5 wt% aques)	4.5–5.5
Salt (wt%)	5.5–6.5
Safety conditions	In 3–25 °C, out of direct sunlight and in polyethylene drums

model as a symbol of the reservoir cross section, with 30 cm length, 7.5 cm inner diameter and 1,325 cm^3 volume, containing two topside flanges. The topside pressures were monitored using two gauges (Indumart, p11t4, range of pressure: 1–60 bar, accuracy: 1 bar, Canada) at the top and bottom. Also, a gauge from stainless steel was used for reading the pressure difference (ΔP) of topsides. Crude oil and seawater were sampled from Bangestan formation in Shadegan oil field and Persian Gulf, respectively. The sands diameter and porosity were 70–100 μm and 35 %, respectively. Cocamidopropyl betaine (CAPB) surfactant was used in this study, and its physical/chemical characteristics are presented in Table 1 and Fig. 2, respectively.

2.2 Setup and Procedures

At the first, the core holder was installed on the setup and the system was examined by air for testing the leakage at pressure 2 bars. The core holder was packed uniformly with silica glass beads by shaking the sand-pack model. Subsequently, the sand-pack model was saturated with crude oil at 1 bar pressure. Afterward, water (or aqueous mixtures) was/were injected into the injection well located on the bottom of the model. The pressure of injected water was measured using a calibrated gage. Then, water was injected into the model at pressure 1 bar, and the oil was produced from top of the model (production well). In this step, the time and the difference pressure (ΔP) were monitored and noted for every 1.0 ml of the produced oil. The graph of volume versus time was plotted, and the amount of produced oil was determined.

Fig. 2 The chemical structure of surfactant



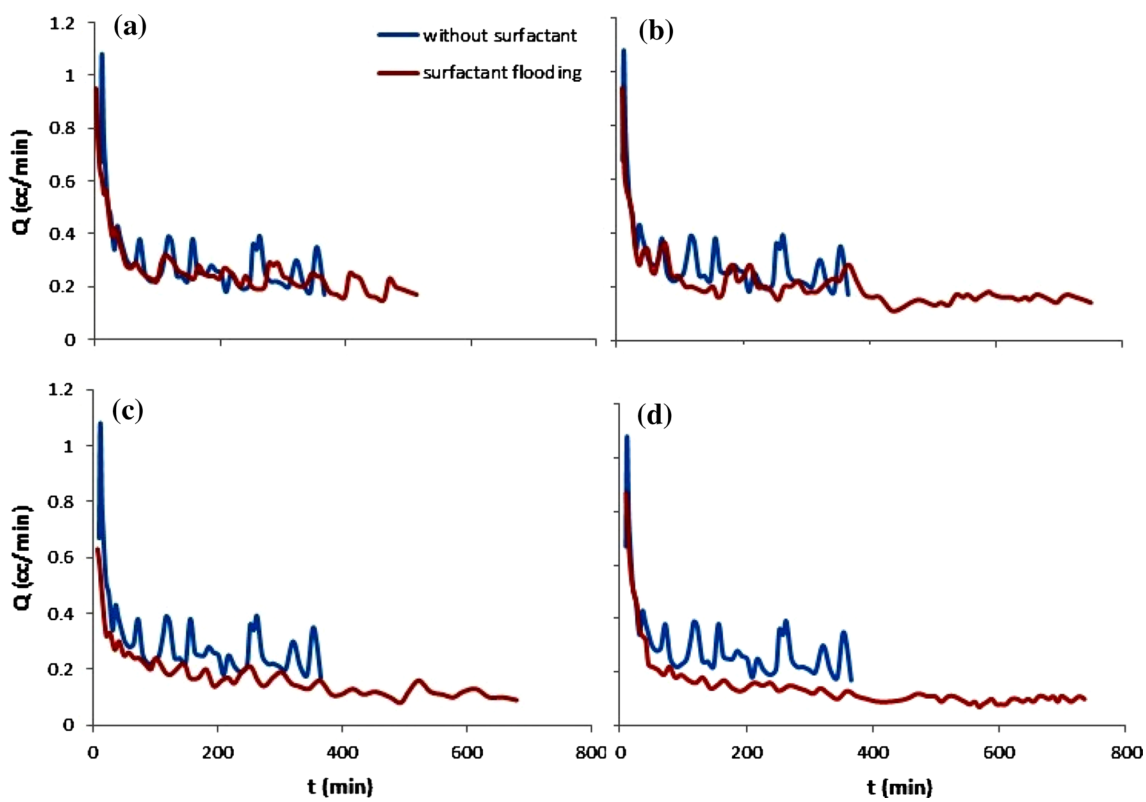
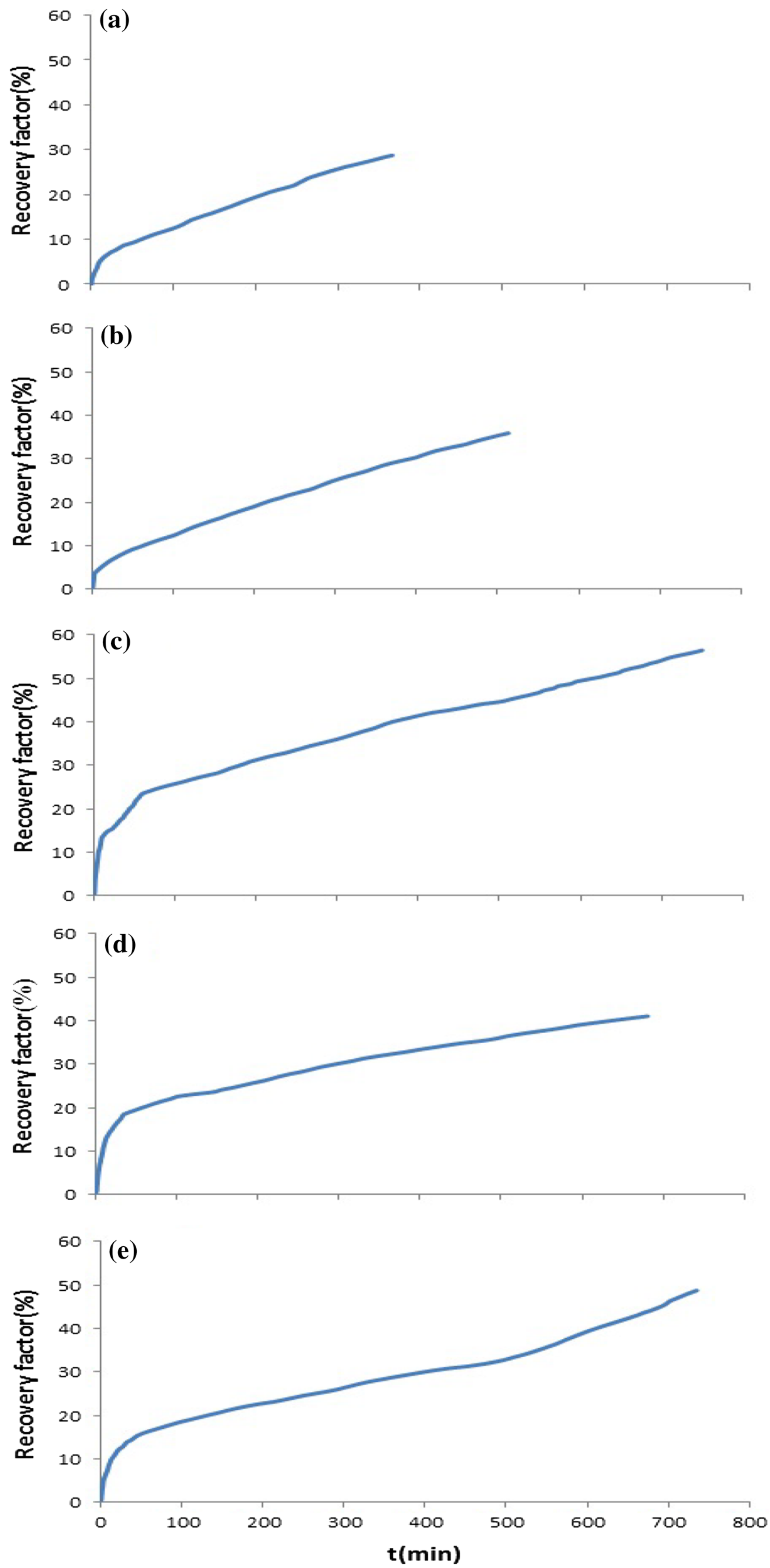


Fig. 3 Effect of the surfactant concentration on the flow rate of produced oil. **a** 0.75 % v, **b** 0.50 % v, **c** 0.25 % v, **d** 0.10 % v

Fig. 4 Recovery factor versus time graph for surfactant injection at different concentrations **a** 0.00 % v, **b** 0.75 % v, **c** 0.50 % v, **d** 0.25 % v, **e** 0.10 % v



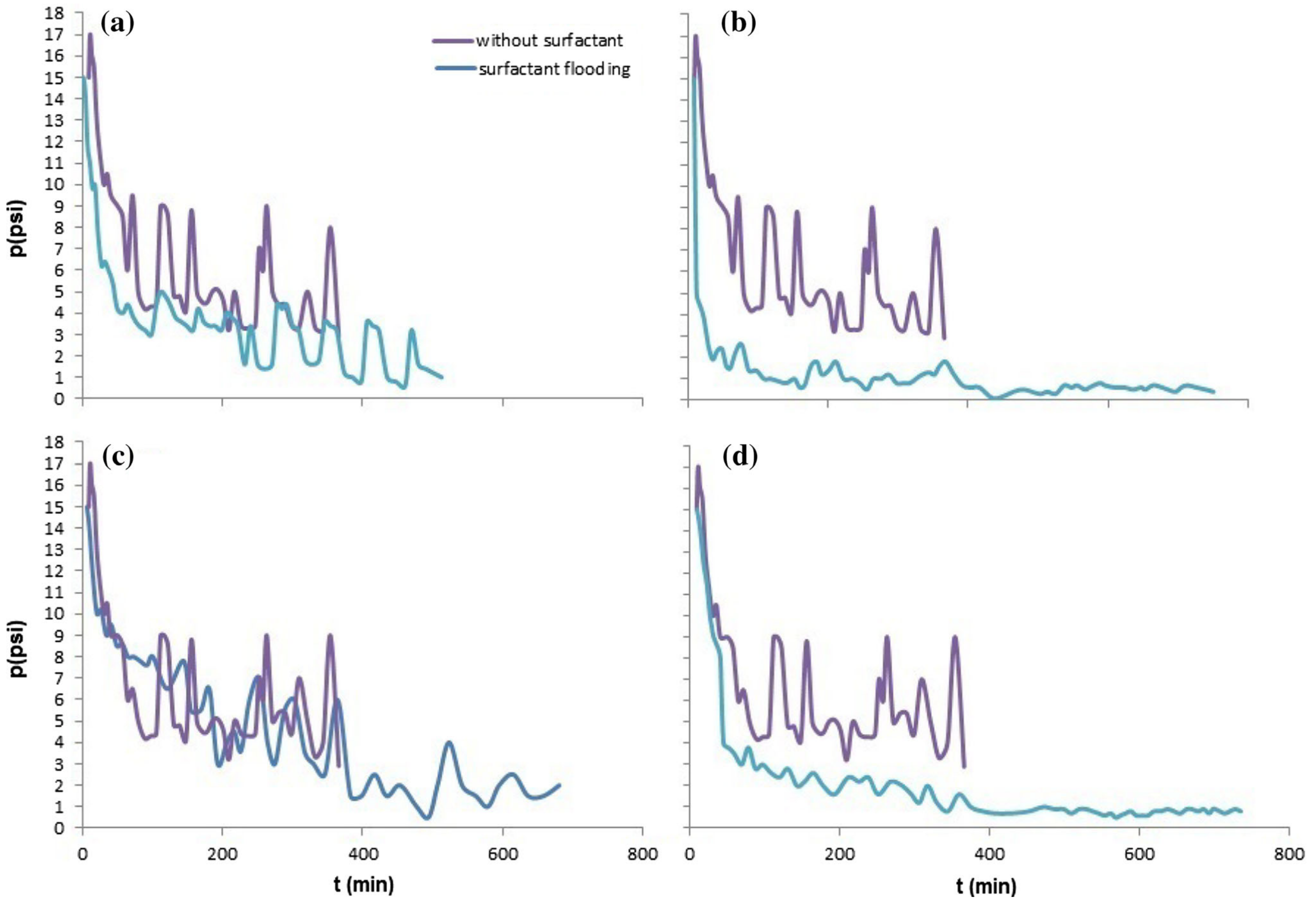


Fig. 5 Pressure drop versus time graph through surfactant injection at different concentrations. **a** 0.75 % v, **b** 0.50 % v, **c** 0.25 % v, **d** 0.10 % v

The experiments were conducted at 15 bar pressure and room temperature. At the end of the experiments, the system was depressurized and the core holder was scanned by a CT-scanner (circular Philips Brilliance 64 Slice, Germany). After depressurization, the glass beads were sampled from 5-6 locations of core holder, and attenuated total reflectance fast Fourier transform infrared spectroscopy (ATR-FTIR, perkin elmer spectrum 65, USA) analysis was carried out on each sample.

Based upon the Darcy's low, the permeability of systems was determined to be in the range of 15–18 D. The injection rate was fixed at 0.33 mL/min, and the backpressure was 15 bars. The viscosity of crude oil and water samples was 21.2 and 2.9 cp., respectively.

3 Results and Discussion

3.1 Effect of the Surfactant Concentration on the Flow Rate

Figure 3 shows the flow rate of the produced oil in the water flooding system (in the presence and the absence of CAPB). In the experiments using CAPB (0.0 and 0.75 % v), the amount of the produced oil was measured to be 112 and 140 cm^3, respectively. Using CAPB (0.50 % v), the amount of the produced oil was determined to be 220 cm^3. This reveals that the maximum produced oil achieved at certain contents of CAPB. Further tasks were performed to find the optimal concentration of CAPB using 0.25 (160 cm^3 produced oil) and 0.10 % v (190 cm^3 produced oil) of CAPB.

Obviously, the fluctuations depicted in Fig. 3d are less than those in Fig. 3a–c. The results showed that water flooding is a suitable method for tertiary oil recovery; however, it suffers from some inherent limitations mainly the limited operation time (caused by breaking through of injected water into the production oil wells). Surfactant is a key factor that solves the aforementioned problems. Figure 4 depicts the recovery data versus time. Figure 5 shows the pressure drop versus time graph through surfactant injection with different concentrations. Figure 6 shows the cumulative oil produced against PV of fluid injected.

Also, they are much effective at low concentrations leading to more economic efficiency. Table 2 represents the results of the surfactant injection tests.

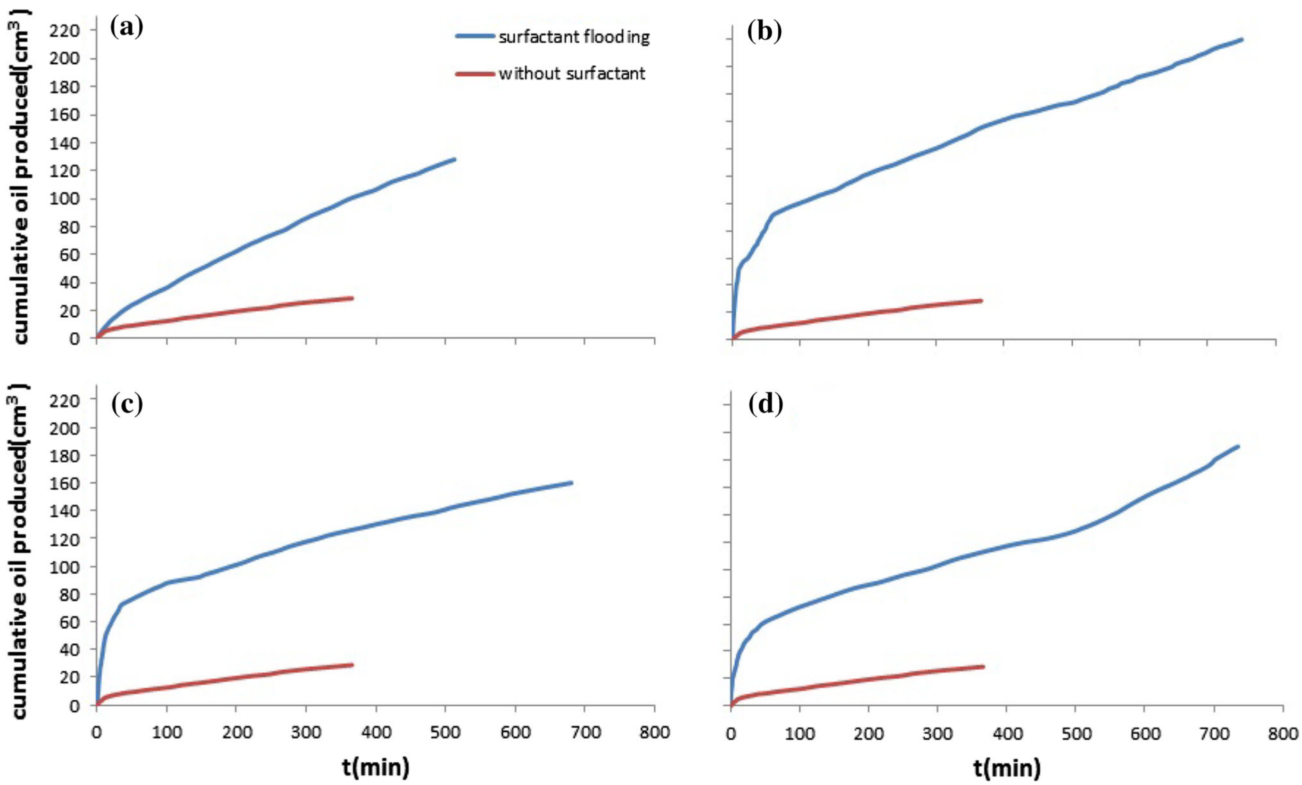


Fig. 6 The cumulative oil produced versus time graph for surfactant injection at different concentrations. **a** 0.75 % v, **b** 0.50 % v, **c** 0.25 % v, **d** 0.10 % v

Table 2 Summary of data through the experiments

Test	Reservoir's volume (cm^3)	Produced oil (cm^3)	Time of recovery (min)	Porosity (%)	Recovery factor (%), before breakthrough
Water injection	1,299.056	112	366	30	29
Surfactant injection (7,500 ppm)	1,299.056	140	513	30	36
Surfactant injection (5,000 ppm)	1,299.056	220	750	30	56
Surfactant injection (2,500 ppm)	1,299.056	160	680	30	41
Surfactant injection (1,000 ppm)	1,299.056	190	735	30	49

3.2 ATR Spectra Interpretation

Figure 7 shows the spectra of residual hydrocarbons (on the surface of glass beads) after the tests of water flooding and surfactant (0.75, 0.50, 0.25 and 0.10 % v) injection. In this figure, the signals 1 and 2 correspond to the polar compounds of crude oil. Obviously, surfactant injection caused decreasing the signals intensity. This reveals that the residual hydrocarbons decreased dominantly. The signals 3 and 4 correspond to the nonpolar compounds of crude oil. The surfactant injection caused decreasing the intensity of signals 3 and 4. The maximum decrease in the signals' intensity achieved at CAPB (0.10 % v).

3.3 Photographs of CT-Scan

The photographs in Fig. 8 show a snapshot after the experiment for water flooding and surfactant (0.10 % v) injection at five sections of the core holder. Black color represents the oil region in the reservoir; white and gray shows the water and the mixture of water/oil region, respectively.

Analyzing Fig. 8W_1 (section 1) reported that the percent of black (oil region), white (water region) and gray (oil and water region) color's area is 11, 13 and 76, respectively. In Fig. 8S_1 (section 1), the percent of these colors are 1, 26 and 73 for black, white and gray pixels, respectively. In Fig. 8W_2 (section 2), the percentages of the colors are 9, 6 and 85 % for

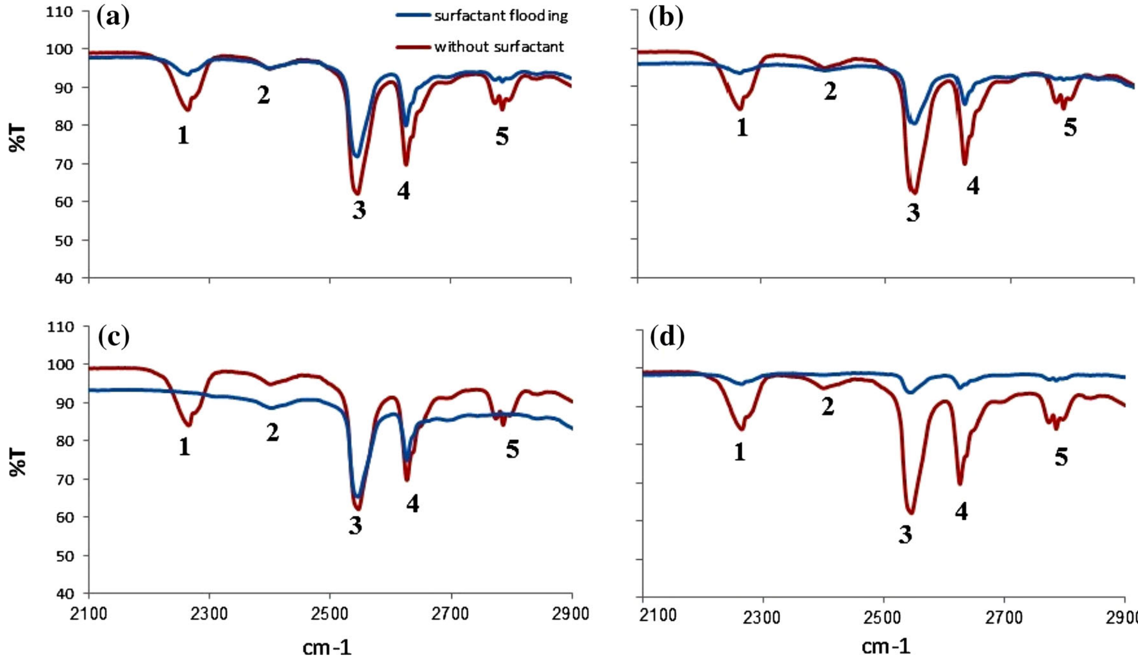


Fig. 7 ATR-IR spectra of residual hydrocarbons on the glass beads after the tests of water flooding and surfactant injection with different concentrations. **a** 0.75 % v, **b** 0.50 % v, **c** 0.25 % v, **d** 0.10 % v

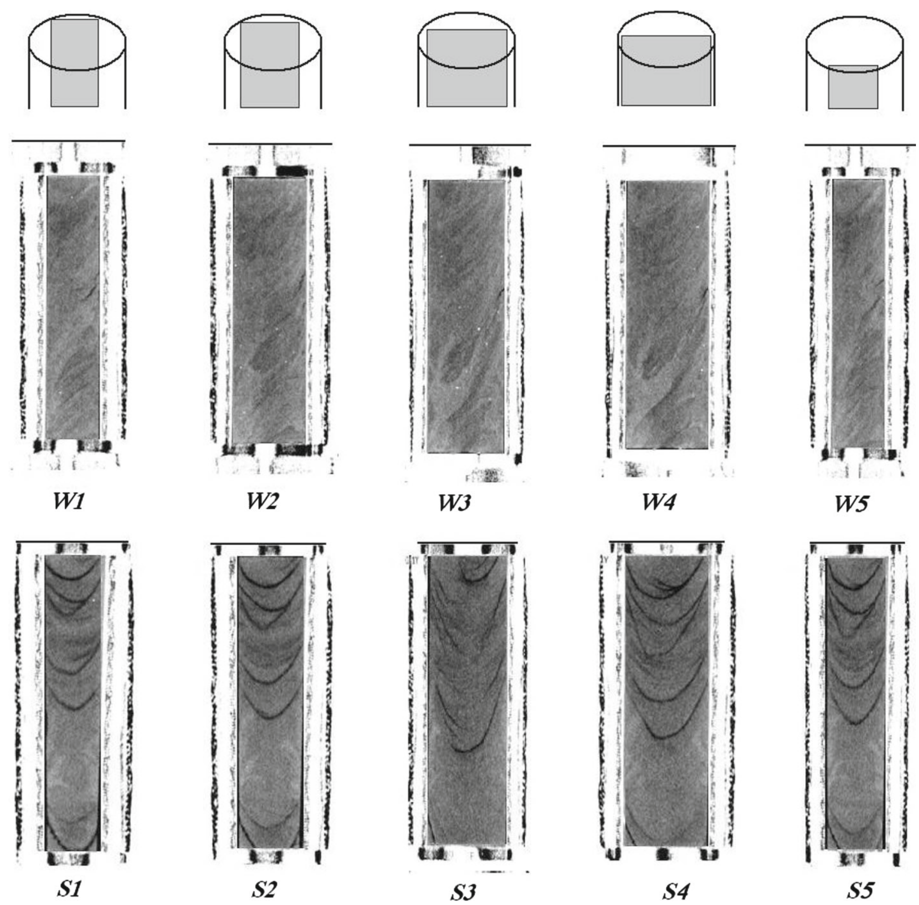


Fig. 8 Photographs of CT-scan. *W* water injection, *S* surfactant injection

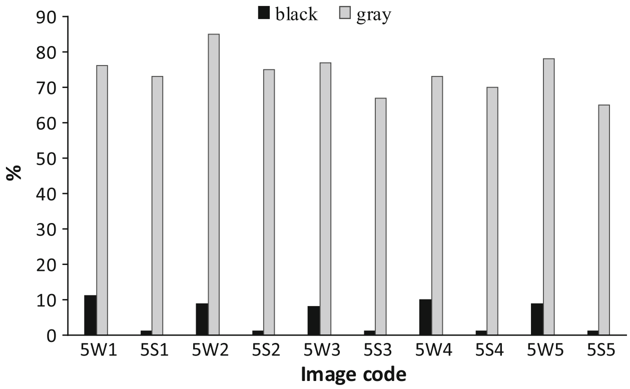


Fig. 9 The *bar chart* representing the colors percentage

black, white and gray pixels, respectively, and for Fig. 8S_2 (section 2), these values are 1, 24 and 75 %. Analyzing the Fig. 8W_3 (section 3) reported that the percents of colors are 8, 15 and 77 for black, white and gray pixels, respectively, and these values for Fig. 8S_3 (section 3) are 1, 32 and 67 %. The percent of black, white and gray color areas are 10, 17 and 73 %, respectively, in Fig. 8W_4 (section 4). Also, these values for Fig. 8S_4 (section 4) are 1, 29 and 70 %. In Fig. 8W_5 (section 5), the percentages of the colors are 9 % for black, 13 % white and 78 % gray pixels. These values for Fig. 8S_5 (section 5) are 1, 34 and 65 %, respectively. Figure 9 shows the bar chart representing the color percentage.

Comparison of colors percentage compositions depicts that the black color area at five sections in water injection is more than surfactant injection. Also, white color area in water injection is less than surfactant injection. Then, the amount of produced oil in water injection is not too considerable, and water does not wash the entrapped crude oil at more regions.

3.4 Mechanism of Recovery Process

Oil recovery mechanism through CAPB injection including four steps: (1) At the first step, CAPB is dissolved in the injected water. Dissolution of surfactants in the injected saline water follows the relevant equations. (2) The injected water (CAPB solution) makes an emulsion at the crude oil interface. (3) The produced emulsion reduces the oil:water interfacial tension and (4) an inverse emulsion is formed, and the water droplets move to crude oil media. By fast and accelerated dispersing of the water droplets in the oil media, the dispersed droplets of water move to the surface of matrix and form a thick water film. This phenomenon increases the water saturation of matrix and improves its oil permeability and mobility. The mobility of the inverse emulsion is less than that of the residual crude oil. Therefore, the recovery factor and the production rate increase.

The production rate increases by injection of CAPB in concentrations less than 0.50 % v. However, the complementary date (ART) revealed that the maximum recovery factor was achieved at 0.10 % v CAPB. The maximum emulsification is achieved at critical micelle concentration (CMC). The CMC of CAPB in saline injected water was determined at 0.10 % v. At lower and higher concentrations of CAPB, the maximum emulsification cannot be achieved.

4 Conclusions and Suggestions

The water flooding process is a suitable method for tertiary oil recovery; however, it suffers from some inherent limits mainly the short operation time caused by breaking through of injected water into the production oil wells. Surfactant is a key factor that solves the aforementioned problems. Surfactant injection has higher efficiency than water flooding owing to creating the nano-size aggregates. Surfactants are much effective at low concentrations leading to more economic efficiency. The maximum produced oil achieved at certain contents of CAPB (0.10 % v). Based upon the ATR-FTIR data, the injection of surfactant caused decreasing the polar and nonpolar compounds of crude oil and the maximum decreasing the signals intensity achieved at CAPB (0.10 % v). The photographs taken from CT-scan at five sections of the core holder in water injection test show that water does not wash the entrapped crude oil at more regions. Comparison of the color percentage compositions reported that the black color area at five sections in water injection is more than surfactant injection. Also, white color area in water injection is less than surfactant injection. Then, the amount of produced oil in water injection is not too considerable.

Some side researches are needed to complete the previous investigations at EOR fields. Nanoparticles and water flooding are new technologies; thereby, there are many questions and unknown problems in this field, for example: (1) Using amphoteric surfactant for enhancing oil recovery in fractured reservoirs. (2) Using anionic and amphoteric (mixed) surfactants. (3) Studying on injecting water and reservoir water consistency. (4) Studying at injecting pressure field. (5) Using CAPB in fractured reservoirs.

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