RESEARCH ARTICLE - PETROLEUM ENGINEERING

Effects of Surfactant-Polymer Formulation and Salinities Variation Towards Oil Recovery

Aizuddin Supee · Ahmad Kamal Idris

Abstract Surfactant-Polymer (SP) formulation is a crucial part when dealing with SP flooding. Different formulations using different types and concentrations of combination of surfactant and polymer result in different interfacial tension (IFT) and viscosity obtained and it will affect the amount of oil recovered. Salinity also affects the efficiency of SP flooding. High salinity causes polymer viscosity reduction and optimal salinity results in low IFT. This research is conducted to design SP formulation, select an optimum SP formulation by core flooding tests and to determine the effect of salinity (NaCl) variations towards optimum SP formulation. Nine different SP formulations in constant salinity are designed by using different concentrations of Hydrolized Polyacrylamide (HPAM) and anionic surfactant (Alpha Olefin Sulfonate-AOS). The formulations were characterized in terms of viscosity and IFT. Artificial heterogeneous porous media were used in core flooding tests and only six SP formulations with lowest IFT value were tested. Three different salinities were used for optimum SP formulation with maximum incremental oil recovery after water flood to determine the effects of salinities on polymer viscosity, surfactant IFT, incremental oil recovery after water-flood and also phase behavior. For combination of HPAM and AOS in SP flooding, IFT was only affected by the concentration of surfactant used whereas viscosity is solely dependent on polymer concentration. Core flooding tests performed in heterogeneous porous media shows that there exist an optimum polymer viscosity

and surfactant IFT in SP flooding which can maximize incremental oil recovery and increasing in salinity also results in poor incremental oil recovery.

Keywords Surfactant-Polymer (SP) formulation · Optimum polymer viscosity and surfactant IFT · Incremental oil recovery · Salinity

الخلاصـة

إن تركيبة البوليمر ـ المادة الفعالة سطحيا (SP) هي جزء حاسم عند التعامل مع فيضانات SP. وتؤدي التركيبات المختلفة باستخدام أنواع وتراكيز مختلفة من مزيج المادة الفعالة سطحيا والبوليمر إلى الحصول على توتر بيني مختلف (IFT) ولزوجة مختلفة، وسوف تؤثر في كمية النفط المسترجع. وتؤثر الملوحة أيضا في كفاءة فيضانات SP. وتؤدي الملوحة العالية إلى خفض لزوجة البوليمر ونتائج الملوحة المثلى في التوتر البيني المنخفض. وقد أجري هذا البحث من أجل تصميم تركيبة البوليمر ـ المادة الفعالة سطحيا، وتحديد تركيبة البوليمر ـ المادة الفعالة سطحيا المثلى عن طريق اختبارات الفيضانات الأساسية وتحديد أثر اختلاف الملوحة (كلوريد الصوديوم) والاختلاف نحو تحديد تركيبة البوليمر ـ المادة الفعالة سطحيا المثلى. وقد صممت تسعة تركيبات SP مختلفة في ملوحة ثابتة باستخدام تراكيز مختلفة من بوليمر البولي أكريل أميد المحلل (HPAM) و المادة الفعالة سطحيا ذات الشحنة السالبة AOS (ألفا أولفين ـ سلفونيت) . وتم توصيف التركيبات بالنسبة إلى اللزوجة و التوتر البيني. واستخدمت وسائط منفذة غير متجانسة اصطناعية في اختبارات الفيضانات الأساسية وتم فقط اختبار ستة تركيبات SP مع أدنى قيمة تحويل غير رسمية. واستخدمت ثلاث ملوحات مختلفة لتركيبة SP المثلى مع الحد الأقصى لإسترجاع النفط الإضافي بعد فيضانات المياه لتحديد آثار الملوحة في لزوجة البوليمر، والتوتر البيني السطحي، واستخراج النفط الإضافي بعد فيضانات المياه وأيضا سلوك الحالة. ولمزيج من HPAM و AOS في فيضانات SP، يتأثر التوتر البيني فقط بتركيز المادة الفعالة سطحيا المستخدمة في حين أن اللزوجة تعتمد فقط على تركيز البوليمر. وأظهرت اختبارات الفيضانات الأساسية التي أجريت في الوسائط المنفذة غير المتجانسة على وجود لزوجة بوليمر مثلى و توتر بيني سطحي أمثل في فيضانات SP التي يمكن أن تعظم استخراج النفط الإضافي وتؤدي زيادة الملوحة أيضا إلى استخراج نفط إضافي فقير.

A. Supee (✉) · A. K. Idris
Faculty of Petroleum and Renewable Energy Engineering (FPREE),
Universiti Teknologi Malaysia (UTM),
81310 Johor Bahru, Johor, Malaysia
e-mail: aizuddin@petroleum.utm.my

A. K. Idris
e-mail: kamal@petroleum.utm.my

1 Introduction

An essential requirement for effective oil recovery with Surfactant-Polymer (SP) flooding is SP formulation used must propagate at optimal conditions [1–7]. Optimal conditions means that the interaction between SP formulation with reservoir condition such as salinity and heterogeneity and also surfactant and polymer interactions must be suit each other to achieved maximum oil recovery.

Salinity used in SP formulation affects polymer viscosity and surfactant IFT. Changes in salinity will lead to the changes in surfactant ability to reduce IFT [3] and polymer viscosity ability to displaced oil bank created by surfactant IFT. Ultra-low surfactant IFT can be achieved by optimum salinity [7], whereas high salinity either by monovalent ion or divalent ions will reduce polymer viscosity [2,4,5]. Reduction in polymer viscosity is due to the charge screening effect [4,8,9] and divalent ions such as Ca^{2+} and Mg^{2+} have a severe impact on polymer viscosity compared to the monovalent ion (Na^+) because more effective shielding occurs [5].

Reservoir heterogeneities also affect oil recovery achieved by a specific SP formulation in SP flooding. In homogeneous reservoir, SP formulation with highest polymer viscosity and ultra-low surfactant IFT are required to obtain maximum oil recovery, but it differs when heterogeneities come into consideration. There exist an optimum polymer viscosity and surfactant IFT where the polymer viscosity is high but not the highest possible value, and surfactant IFT is at lowest but not the lowest possible value. This optimum value will result in balance in displacement and sweep efficiency and lead to the maximum oil recovery [1].

In addition, surfactant and polymer interactions are other factors that influence oil recovery, and the interactions involved are described by previous works conducted [7,10–15]. It is better if surfactant and polymer used in SP formulation for at least did not give negative effect in term of viscosity and IFT. For combinations of HPAM and anionic surfactant in SP formulation, surfactant only has a minor impact on HPAM viscosity [11,12] whereas polymer has a little effect on surfactant IFT [13]. In other words, this combination did not sacrifice polymer viscosity and surfactant IFT and thus it may lead to the maximum oil recovery.

There is much research conducted to determine the optimum condition for SP formulation in heterogeneous formations especially in lab scale approach [1,16–18]. Tabary et al. [16] and Shiau et al. [17] consider phase behaviour studies in their experiment whereas Bataweel et al. [18] and Wang et al. [1] did not mention it. Phase behaviour study will indicate the amount of optimum surfactant with or without polymer concentration and optimal salinity required in SP flooding by visual observation. Salinity variation is also being used in an experiment except by Wang et al. [1] who use only

one value of salinity. Surfactant performance is more dependent on salinity variation compared to the polymer. However, there exists an optimal salinity that can produce maximum oil recovery where the surfactant IFT is at the lowest value and this phenomenon is due to the nature of types of phase behaviour formed during salinity variation [3,19].

HPAM and AOS in SP formulation exhibit that IFT only affected by the concentration of surfactant used whereas viscosity is solely dependent on polymer concentration. Core flooding tests performed in heterogeneous porous media shows that the optimum SP formulation that produced maximum incremental oil recovery after water flooding is not the highest polymer viscosity and lowest surfactant IFT, and increasing salinity results in decreasing polymer viscosity and increasing surfactant IFT and lead to poor incremental oil recovery.

2 Experimental Description

2.1 Chemical Solution

Brine was prepared by adding NaCl to de-ionized water with a concentration of 20,000 ppm. Its density was 1.012 g/ml at 28.3 °C and its viscosity was 1.3 cp at 30 °C. Paraffin was used as an oil phase and its density was 0.869 g/ml at 28.3 °C and its viscosity was 16.8 cp at 30 °C. The details of paraffin used are listed in Table 1. Anionic surfactant C14–16, Alpha Olefin Sulfonate (AOS) supplied by Stepan Company (USA) and Hydrolized Polyacrylamide (HPAM) supplied by TIANJIN ZHONGXIN CHEMTECH CO. LTD. (China) were used in SP formulation. Table 2 lists the SP formulation designed. Different salinities (40,000 and 60,000 ppm) in optimum SP formulation also prepared as same manner as 20,000 ppm.

2.2 Viscosity Measurement

Brookfield Viscometer DV-III Model was used to determine the viscosity of the brine, oil and SP formulation. Temperature was set to 30 °C during the viscosity measurement at various shear rates.

Table 1 Paraffin details

Details/properties	Description
Supplier	QReC
Purification	Extra pure
Kinematic viscosity at 37.8 °C	Not more than 30cS
Density at 60 °F	0.8421 g/ml
API gravity at 60 °F	36.45° API
Specific gravity at 60/60 °F	0.8425

Table 2 Surfactant-polymer (SP) formulation in constant salinity (20,000 ppm NaCl)

Surfactant (AOS) (% weight)	HPAM concentration (ppm) / Formulation No.		
	200	400	600
0.00	Benchmark	Benchmark	Benchmark
0.05	*1	*4	*7
0.10	*2	*5	*8
0.15	*3	*6	*9

2.3 IFT Measurement

KRUSS Tensiometer K6 Model (ring method) was used to determine the IFT of oil-water and oil-SP formulation. Temperature was set to 28.3 °C and measurement procedure and reading correction was done according to the ASTM D971-99a (2004).

2.4 Phase Behavior Observation

Phase behavior of oil and optimum SP formulation were determined by mixing both liquids into the different test tubes for each formulation at 28.3 °C. The solution was shaken for 10 min and was left for 7 days to allow the reaction between the liquids to be stable before phase behavior was recorded.

2.5 Artificial Heterogeneous Porous Media

Glass bead model consisting of two different ranges of glass bead sizes (125 µm to <355 µm and 850 µm to <1.18 mm) with volume ratio 1:1 was used as artificial heterogeneous porous media for core flooding tests. No treatment done to the glass bead and the wettability of the glass bead was water-wet. The diameter of the core was 3.6 cm and the length was 33 cm. Dry packing method was used to pack the glass bead inside the core. The glass bead inside the core holder was designed in the form of layer. Initially bigger glass bead size (850 µm to <1.18 mm) was inserted into the core holder until quarter of the core length. Next, another half of the core length was filled with smaller glass bead size (125 µm to <355 µm) and bigger glass bead size (850 µm to <1.18 mm) was used to filled the last quarter of the core length. The core was vacuumed using a vacuum pump for 4 h before conducted liquid saturating method for porosity (ϕ) determination. The permeability (k) was determined by using Darcy linear flow equation. The porosity and permeability of the core were 38 % and 2 Darcy respectively.

2.6 Core Flood Tests

Core flood tests were conducted at 28.3 °C and only six from nine SP formulations were selected based on the lowest IFT value. Water flooding was conducted first to determine water flood recovery followed by SP flooding for incremental oil recovery. Injected pore volume (PV) designed was 1.5 PV for water flood, 0.3 PV for SP formulation and lastly 1.5 PV for water flood. The flow rate used was 0.5 ml/min and 20,000 ppm NaCl was used as displacing fluid in water flood.

2.7 Core Cleaning and Preparation for Core Flood Test

A single core was used for core flooding tests and the core was cleaned up by injection of 2 PV of toluene and followed by 3 PV of 20,000 ppm NaCl. Flow rate set for both fluids was 5 ml/min. It was followed by vacuumed the core for 4 h and then saturated it with 20,000 ppm NaCl. The process was repeated before proceed with next core flooding test.

3 Results and Discussion

3.1 Porosity and Permeability

The result of the porosity of the core was 38 % whereas the average permeability was 2 Darcy. Even though the value of permeability was higher than reservoir condition which is normally in miliDarcy unit [20], however the setup core still can be used in rough estimation of SP flooding performance prediction because the value of permeability still falls under reservoir criteria which is favorable for SP flooding [20–22]. During permeability measurement, the differential pressure (ΔP) value was fluctuated between 0.17 and 0.19 bar and average ΔP was considered in permeability calculation. Different results observed when same dimension of homogeneous core was used. The homogeneous core which consist of 125 µm to <355 µm glass bead size results in almost constant ΔP (0.21 bar). These fluctuation in pressure confirmed that the core was heterogeneous due to the variation in permeability.

3.2 Effect of Shear Rates on HPAM and SP Formulation Viscosity

Figure 1 shows the effect of shear rates on HPAM, brine and oil whereas Fig. 2 illustrate the effect of shear rates on nine SP formulation. HPAM and SP formulation exhibit non-Newtonian effects where at higher shear rates, the viscosity decrease. This trend also shows a similarity with previous works conducted [4,23,24]. Higher shear rates will result in
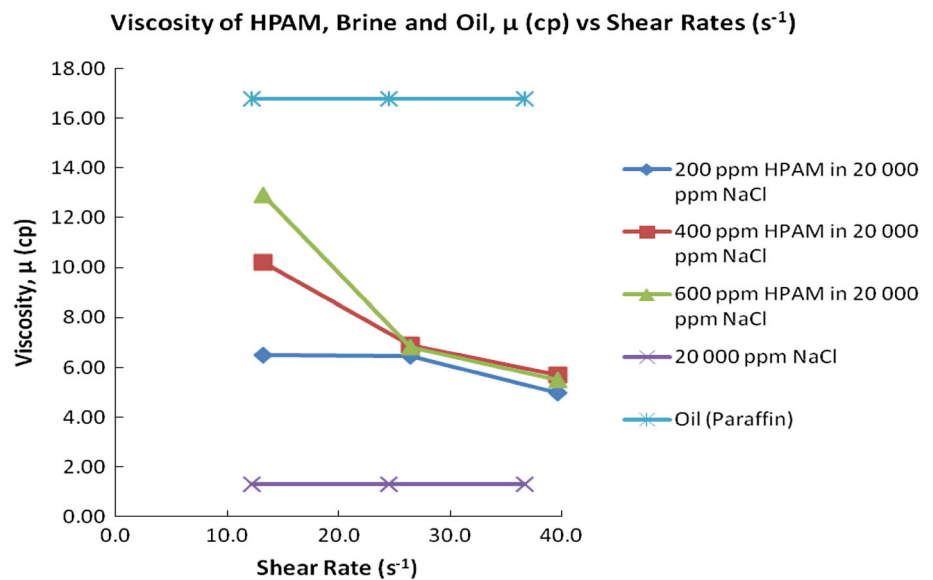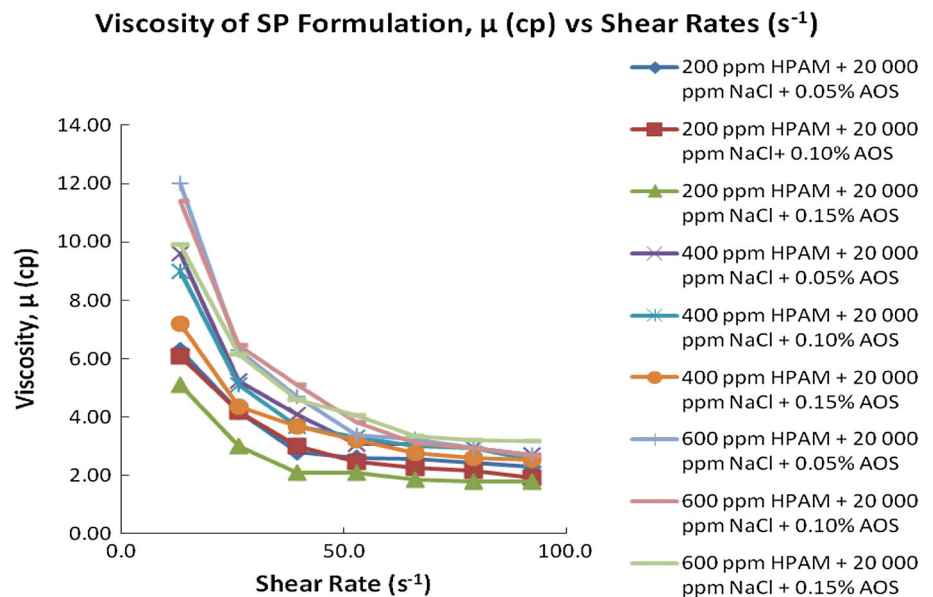
viscosity reduction for polymer solution caused by molecular mechanism [25]. If very low shear rates applied to a solution, the random ground state remains undisturbed and thus the viscosity produced remains constant for some shear rate range. When the shear reaches a critical value at which random ground state is being disturbed, the molecules arrange themselves in a way as to present the least resistance to flow. Polymer chains exhibit alignment along the flow lines created by the shear field and viscosity decreases as the shear rate increases. The second Newtonian range starts when all the molecules are aligned but the value of viscosity is less than first Newtonian range. Brine and oil are Newtonian fluids where the viscosity of solution is independent on shear rates.

3.3 Effect of HPAM Concentration on Viscosity and AOS IFT

Viscosity of HPAM was dependent on polymer concentration and it is depicted in Fig. 3. Adding more concentration of HPAM from 200 to 600 ppm will lead to the increase in viscosity of polymer solution. The results obtained was in agreement with the results produced by previous researchers where increasing in polymer concentration will caused in increasing polymer viscosity [2,8,26,27].

AOS IFT was not affected by HPAM concentration. Polymer in SP solution normally stays in the most aqueous phase and it differs with surfactant which can stays in different phases [14,15]. The effect of HPAM concentration on sur-

factant IFT is shown in Fig. 4. The changes in IFT for the surfactant were small and can be neglected even though polymer concentration was increased from 200 to 600 ppm. Changes in IFT for HPAM solution was only due to the concentration of surfactant used and not due to the polymer concentration. This trend also observed by previous works conducted where only a little difference in IFT values with and without polymer [7,10,13].

3.4 Effects of AOS Concentration on IFT of SP formulation and HPAM Viscosity

Surfactant concentration plays a vital role in IFT reduction of HPAM solution. Below the critical micelle concentration (CMC), increasing surfactant concentration will lead to the IFT reduction of solution whereas above CMC, increase in surfactant concentration only results in increasing micelle

Viscosity of polymer (HPAM) 20 000 ppm NaCl, μ (cp) vs polymer concentration (ppm)

Fig. 3 HPAM viscosity as a function of polymer concentration measured at shear rate 13.2 s^{-1}

Fig. 4 Effect of polymer (HPAM) concentration on surfactant (AOS) IFT

concentration without give significant reduction in IFT [24]. The value of CMC and surface tension of AOS alone in aqueous solution was found to be 5 % surfactant concentration and 36.9 mN/m respectively, however temperature used during measurement was not mentioned [28]. Figure 5 illustrate the effect of AOS concentration on IFT of SP formulation. IFT for HPAM alone for different concentration (200, 400 and 600 ppm) was dropped significantly when 0.05 % surfactant concentration used. However, when the concentration of surfactant increased from 0.05 to 0.15 %, only small changes in IFT noticed for SP formulation. Lowest IFT value was obtained for 200 ppm HPAM in 20,000 ppm NaCl at 0.15 % surfactant concentration which is 4.92 mN/m.

The effect of AOS concentration on HPAM viscosity is shown in Fig. 6. Only small changes noticed which can be neglected when different concentration of surfactant used for different HPAM concentration (200, 400 and 600 ppm). The trend produced also have a similarity with previous works conducted [11,12,29]. However, different result produced when the anionic surfactant concentration added to the HPAM prepared in de-ionized water [30]. The viscosity of HPAM reduced significantly when anionic surfactant concentration increased and they concluded that it is due to the charge shielding mechanism. Salinity effect may be the major factor contributing to these different trends. Normally, SP flooding will use produced water which is saline water in formulate SP formulation [16,31].
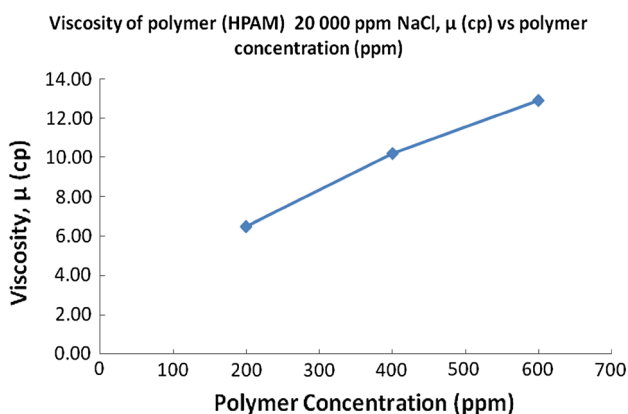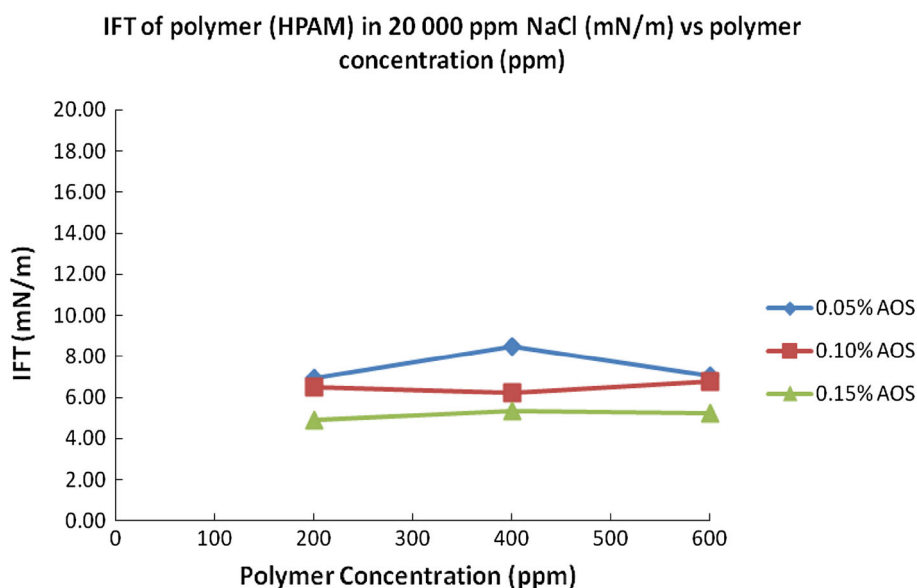
3.5 Core Flood Results for SP Formulation in Constant Salinity (20,000 ppm NaCl)

From nine SP formulations designed, six SP formulations were selected based on the lowest IFT value for SP flooding.

IFT of polymer (HPAM) in 20 000 ppm NaCl (mN/m) vs polymer concentration (ppm)

Fig. 5 IFT of SP formulation at different surfactant (AOS) concentration

IFT of SP formulation (mN/m) vs surfactant (AOS) concentration (%)

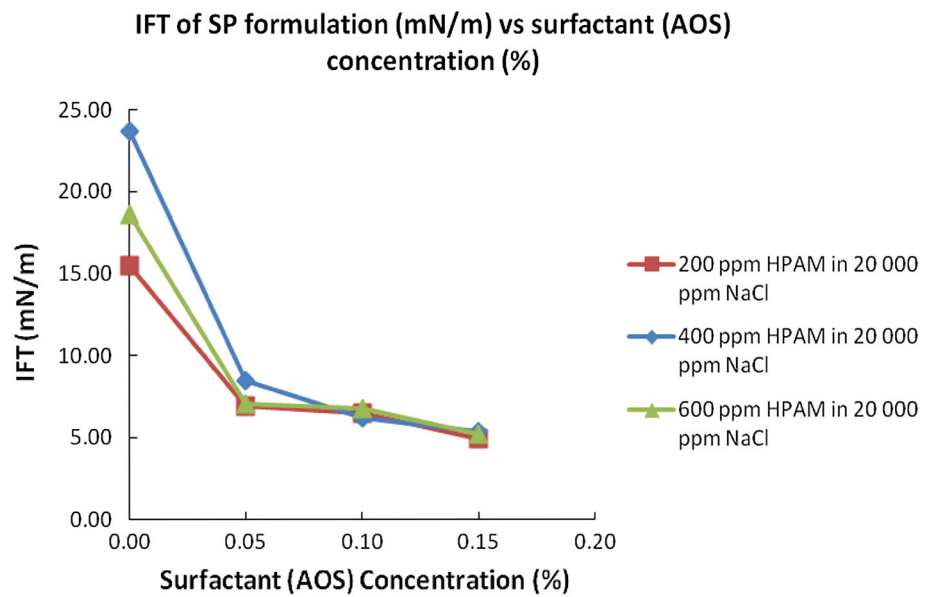Fig. 6 Effect of surfactant (AOS) concentration on HPAM viscosity

Viscosity of SP formulation, μ (cp) vs surfactant (AOS) concentration (%)
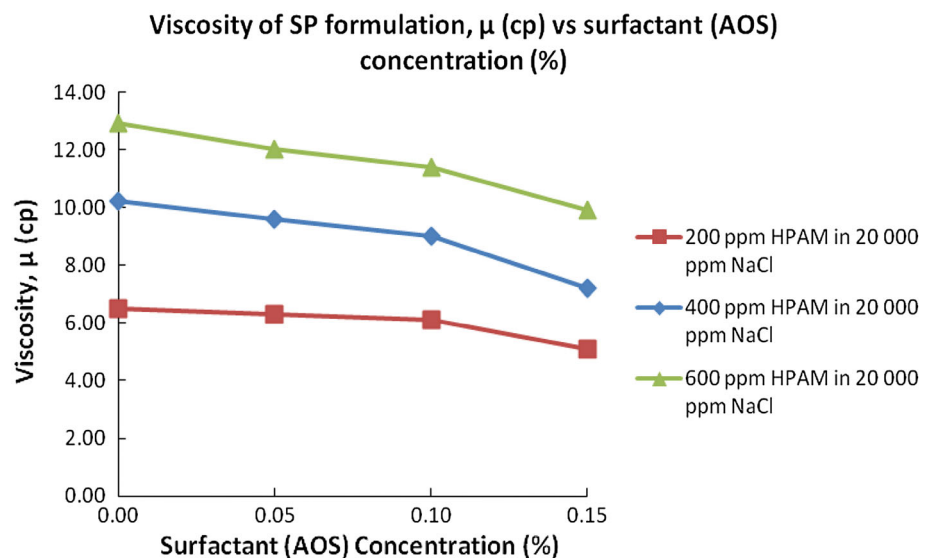

Table 3 Core flood results for SP formulation in constant salinity (20,000 ppm NaCl)

SP formulation No.	Water flood recovery (%)	Incremental oil recovery by SP formulation (%)	Total oil recovery (%)
2	69.65	5.36	75.01
3	65.00	9.17	74.17
5	68.42	5.26	73.65
6	70.59	15.68	86.27
8	68.52	9.26	77.78
9	66.67	7.41	74.08

Table 3 list core flood results whereas Fig. 7 shows the plots of SP formulation from core flooding tests towards incremental oil recovery. From Fig. 7, highest incremental oil recovery

obtained was not SP formulation which has lowest IFT value which is 200 ppm HPAM prepared in 20,000 ppm NaCl and 0.15 % AOS but the SP formulation was 400 ppm HPAM prepared in 20,000 ppm NaCl and 0.15 % AOS. Highest viscosity of SP formulation which is 600 ppm HPAM prepared in 20,000 ppm NaCl and 0.15 % AOS also results in low incremental oil recovery. The properties of optimum SP formulation which give highest incremental oil recovery were not the lowest IFT value or highest viscosity, but the value was an optimum value which is 7.20 cp at shear rate 13.2 s^{-1} and 5.34 mN/m.

The reason of an optimum value of SP formulation was due to the core heterogeneity such as permeability variation. Permeability was varied due to the different ranges of glass bead sizes (125 μm to <355 μm and 850 μm to <1.18 mm)

used. The results obtained have a similarity with results produced by previous researchers when they considered permeability variation in their research [32]. Wang et al. [1] also shows that permeability variation results in maximum incremental oil recovery for optimum SP formulation. In their works, they found that for homogeneous core ($k = 2\,\mu m^2$), the highest incremental oil recovery (28.85 %) was achieved under the condition of highest polymer viscosity (21 mPa s) and ultra-low IFT (5.843×10^{-4} mN/m). However, different results obtained when the highest polymer viscosity and ultra-low IFT was used in heterogeneous core with three different permeabilities ($k = 0.5\,\mu m^2$, $k = 1.0\,\mu m^2$, $k = 2.0\,\mu m^2$). There exist an optimum SP formulation that resulted in highest incremental oil recovery (18.7 %). The properties of this optimum SP formulation was not the highest polymer viscosity and ultra-low IFT but it was at an appropriate value which are 8.28 mPa s and 1.865×10^{-2} mN/m. They also conduct visualized model experiments to investigate the possible mechanism for the existence of this optimum SP formulation and they found that larger emulsified oil droplet produced by low IFT (1.511×10^{-2} mN/m) compared to the ultra-low IFT (3.749×10^{-3} mN/m). This larger emulsified oil droplet proved that sweep efficiency was improved and thus results in highest incremental oil recovery. Based on the results obtained and similarity between previous researchers, it can be concluded that in heterogeneous formation which varied in permeability, it is the best to have balance sweep efficiency and displacement efficiency to achieve maximum oil recovery and this can be done by SP formulation which has optimum polymer viscosity and surfactant IFT. The viscosity of the polymer solution is high but not the highest possible value and surfactant IFT is low but not the lowest possible value.

Surfactant-polymer interactions also contribute to this optimum value factor. Anionic type of surfactant (AOS) used only affect reduction in IFT and has a small effect on SP formulation viscosity which can be neglected. The trend produced also has a similarity with previous works conducted by Li [11] and Kang [12]. SP formulation viscosity only affected by HPAM concentration. Optimum HPAM and AOS concentration used results in an ideal reaction between SP formulation and heterogeneous formation. There are no undesired effects and the ability of SP formulation to displace and sweep the oil is remains high and unaffected.

3.6 Effects of Salinities Variation on Optimum SP Formulation Viscosity and IFT

Salinities also affect the viscosity and IFT of SP formulation. In this case only monovalent effect (Na^+ in NaCl) was considered even though the effects of other cations also affected SP formulation [2,5]. Figure 8 described the effects of NaCl concentration on optimum SP formulation measured at various shear rates. Increasing in salinity from 20,000 to 60,000 ppm NaCl will reduced optimum SP formulation viscosity and the trend also observed at various shear rates measured. 60,000 ppm NaCl exhibit poor SP formulation viscosity reduction which is dropped from 7.20 cp at 20,000 ppm NaCl to 4.50 cp at 60,000 ppm NaCl.

The phenomena of viscosity reduction with increasing salinity was due to the charge screening effects. A polymer like HPAM, when it is exposed to the different type of saline water, its anionic and cationic in the water would have attraction/repulsion to the polymer chain, and make it compressed or stretched. As the concentration of Na^+ in NaCl

Fig. 7 Plots of different SP formulation towards incremental oil recovery

Incremental Oil Recovery (%) vs Pore Volume Injected, PV (ml)

Legend:
- 200 ppm HPAM + 20 000 ppm NaCl + 0.10% AOS
- 200 ppm HPAM + 20 000 ppm NaCl + 0.15% AOS
- 400 ppm HPAM + 20 000 ppm NaCl + 0.10% AOS
- 400 ppm HPAM + 20 000 ppm NaCl + 0.15% AOS
- 600 ppm HPAM + 20 000 ppm NaCl + 0.10% AOS
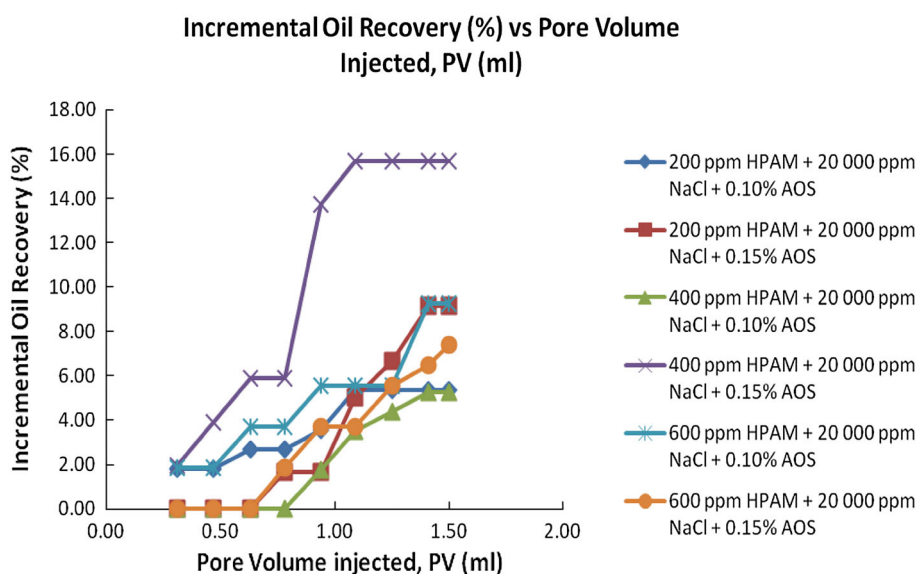- 600 ppm HPAM + 20 000 ppm NaCl + 0.15% AOS

Fig. 8 Effects of salinities variation on optimum SP formulation viscosity

Fig. 9 Effects of salinities variation on optimum SP formulation IFT

Fig. 10 Phase behaviour of optimum SP formulation in different salinities
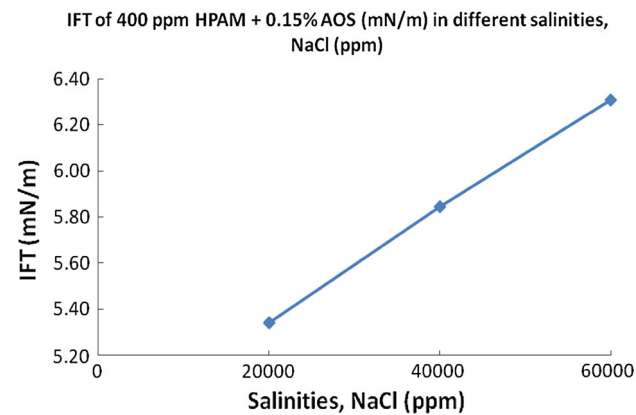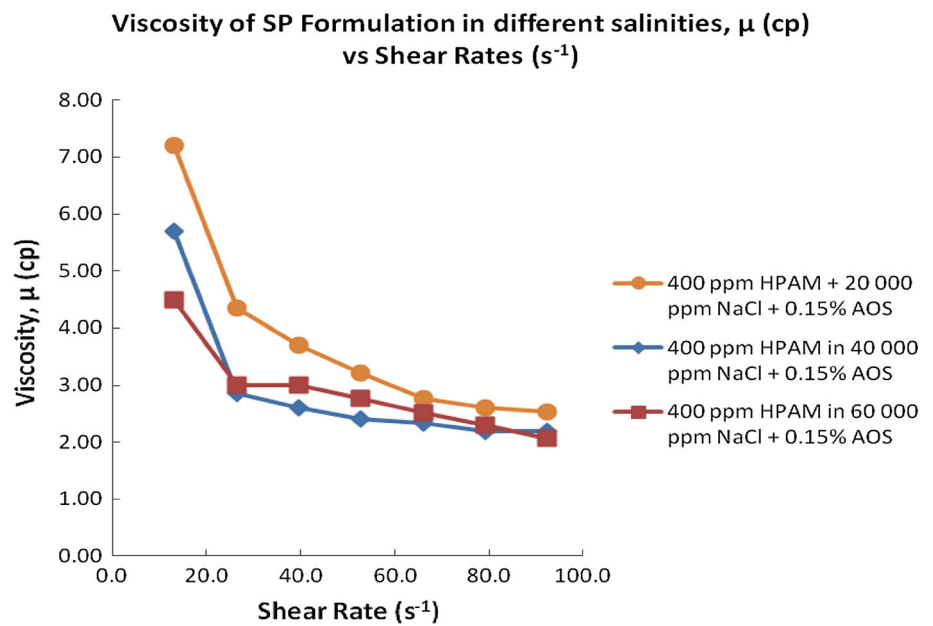
solution increases, the repulsive forces within the polymer chain decrease due to the charge screening effects and the chain coils up. This change in the polymer chain conformation causes the hydrodynamic radius of the chain to decrease and the degree of polymer chain entanglement to diminish. Both factors cause the polymer solution viscosity to decrease [4]. However, when all the charges on the polymer chain are completely shielded with cation, increasing NaCl concentration further will not change the polymer chain configuration and as a result, viscosity of polymer solution remain constant [8,9].

IFT of optimum SP formulation at different salinities is depicted in Fig. 9. Increasing in salinity from 20,000 to 60,000 ppm NaCl will increase optimum SP formulation IFT from 5.34 to 6.31 mN/m. In high brine salinity, the ability of surfactant solubility in the aqueous phase is reduced by electrostatic forces of the brine. As a result from that, the ability
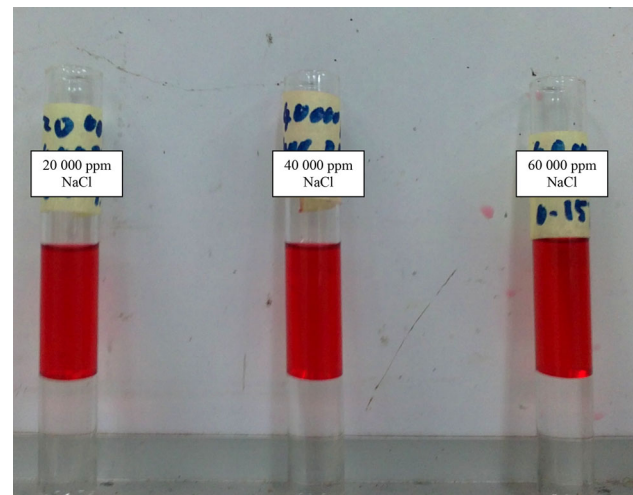
of surfactant in solution to reduced IFT also decreased [3, 24]. This is the reason why optimum SP formulation exhibit increasing IFT value with increasing salinity.

3.7 Phase Behavior Observation for Optimum SP Formulation in Different Salinities

Salinity will controls the type of micro-emulsion phase system generated by a typical surfactant in solution [3, 24]. This type of micro-emulsion phase can be categorized into three types which are Type II(−) or Winsor Type I (lower-phase micro-emulsion), Type II(+) or Winsor Type II (upper-phase micro-emulsion) and Type III or Winsor Type III (middle-phase micro-emulsion). Phase behavior was observed after

leaving the oil in SP formulation for 7 days. The red colour indicates oil (paraffin) and the clear one indicated SP formulations. Figure 10 shows phase behavior of optimum SP formulation in three different salinities.

Phase behavior for optimum SP formulation shows two phases formed. No different in term of phase behavior observed for optimum SP formulation in different salinities, however, optimum SP formulation IFT increase and viscosity decrease as salinities increase. This system is called as Type II(+) system or Winsor Type II because increasing in salinity will lead to increasing optimum SP formulation IFT [3]. In high brine salinity, there will be two phases can form near oil-brine interfaces which are an excess brine phase and an oil external micro-emulsion phase containing surfactant and some solubilised brine.
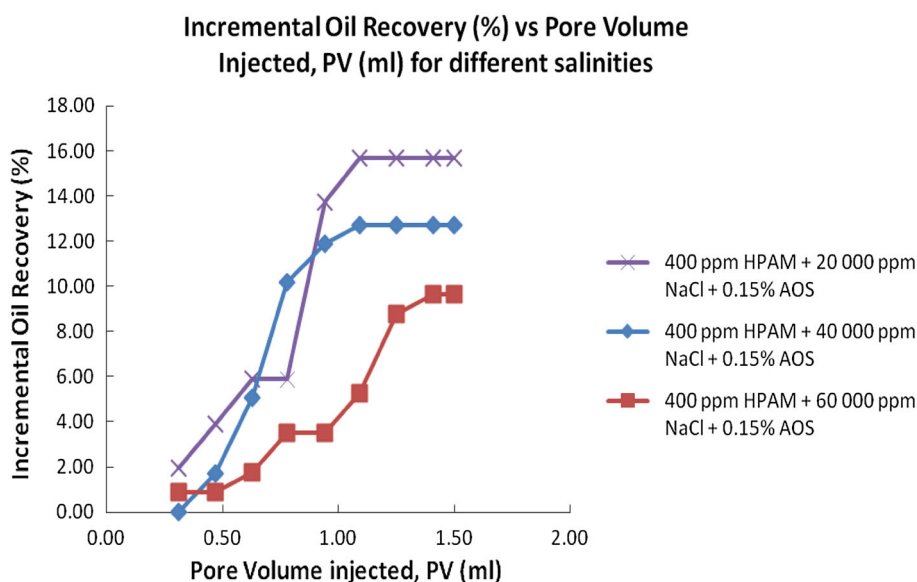
3.8 Core Flood Results for Optimum SP Formulation in Different Salinities (20,000, 40,000 and 60,000 ppm NaCl)

Table 4 list core flood results whereas Fig. 11 shows incremental oil recovery for optimum SP formulations in different salinities. Incremental oil recovery was decreased from

Table 4 Core flood results for optimum SP formulation in different salinities

Salinity (ppm NaCl)	Water flood recovery (%)	Incremental oil recovery by SP formulation (%)	Total oil recovery (%)
20 000	70.59	15.68	86.27
40 000	69.49	12.71	82.20
60 000	71.93	9.65	81.58

15.68 to 9.65 % when the salinity in optimum SP formulation increased from 20,000 to 60,000 ppm NaCl.

This is due to the salinity effects which reduce the ability of SP formulation to perform well in term of viscosity and IFT. When the viscosity reduced, sweep efficiency is the main issue where the ability of SP formulation to sweep the oil reduced. Displacement efficiency also becomes poorer with increasing salinity because the ability of surfactant in SP formulation to mobilized trapped oil decreased. Similar trend also produced by previous researchers regarding to the viscosity reduction with increasing salinity [2,4,5] and IFT increase with increasing salinity [3,24].

4 Conclusions

Experiments were conducted to determine the effects of SP formulation and salinity on oil recovery. Based on the research done, the conclusions are as followed:

1. SP formulation exhibits a viscosity increasing trend when the concentration of HPAM in SP formulation increases. The IFT of SP formulations also decreases with increasing anionic surfactant (AOS) concentration.
2. Core flooding test based on six formulations with lowest IFT indicate that there exist an optimized polymer viscosity and surfactant IFT in SP formulation that can lead to the maximum oil recovery. Higher viscosity and ultra-low IFT is not necessary when heterogeneity come into the consideration.
3. Salinity affects SP formulation viscosity, IFT and phase behavior. Even though same phase behavior observed at salinities used, high salinity reduces the SP formu-

Fig. 11 Incremental oil recovery after water flood for optimum SP formulation in different salinities (NaCl)

Incremental Oil Recovery (%) vs Pore Volume Injected, PV (ml) for different salinities

- 400 ppm HPAM + 20 000 ppm NaCl + 0.15% AOS
- 400 ppm HPAM + 40 000 ppm NaCl + 0.15% AOS
- 400 ppm HPAM + 60 000 ppm NaCl + 0.15% AOS

lation viscosity and increases the SP formulation IFT. As a consequences, oil recovery becomes poorer due to un-mobilized oil and un-swept oil.

New database regarding to the formulation, phase behavior observation, surfactant IFT and polymer viscosity will be developed and can be applied to the field scale which has the same condition and parameters. The amount of oil recovered for field implementation can be roughly estimated by using the developed database.

References

1. Wang, Y.; Zhao, F.; Bai, B.: Optimized surfactant IFT and polymer viscosity for surfactant-polymer flooding in heterogeneous formations. In: SPE Improved Oil Recovery Symposium 2010, Society of Petroleum Engineers, Tulsa (2010)
2. Aluhwal, O.K.H.: Simulation study of improving oil recovery by Polymer Flooding in a Malaysian Reservoir. In: Department of Petroleum Engineering, Universiti Teknologi Malaysia, p. 212, (2008)
3. Zolotukhin, A.B.; Ursin, J.R.: Introduction to petroleum reservoir engineering. Høyskoleforlaget, Norwegian Academic Press, (2000)
4. Nasr-El-Din, H.A.; Taylor, K.C.: Rheology of water-soluble polymers used for improved oil recovery, Chap 24. In: Nicholas, P.C. (ed) Advances in Engineering Fluid Mechanics: Multiphase Reactor and Polymerization System Hydrodynamics. Gulf Professional Publishing, Burlington, p. 615–668, (1996)
5. Ryles, R.G.: Chemical stability limits of water-soluble polymers used in oil recovery processes. SPE Reserv. Eng. 3(1), 23–34 (1988)
6. Sharma, A.K.; Pithapurwala, Y.K., Shah, D.O.: Selection criteria and formation of a surfactant slug for high-temperature, moderate salinity reservoir conditions. In: SPE Oilfield and Geothermal Chemistry Symposium. 1983 Copyright 1983 Society of Petroleum Engineers, Denver (1983)
7. Healy, R.N.; Reed, R.L.; Stenmark, D.G.: Multiphase Microemulsion Systems. Soc. Petroleum Eng. J. 16(3), 147–160 (1976)
8. Sun, Y.; Saleh, L.; Bai, B.: Measurement and impact factors of polymer rheology in porous media. In: Vicente, D.J.D. (ed) Rheology, InTech., p. 187–202 (2012)
9. Lee, S., et al.: Development of a comprehensive rheological property database for EOR polymers. In: SPE Annual Technical Conference and Exhibition. Society of Petroleum Engineers, New Orleans (2009)
10. Hongyan, W., et al.: Development and application of dilute surfactant–polymer flooding system for Shengli oilfield. J. Petroleum Sci. Eng. 65(1–2), 45–50 (2009)
11. Li, H.-B.: Advances in alkaline-surfactant-polymer flooding and pilot tests. Science Press, China (2007)
12. Kang, W.-L.: Study of chemical interactions and drive mechanisms in Daqing ASP flooding. Petroleum Industry Press, Beijing (2001)
13. Pope, G.A., et al.: The effect of several polymers on the phase behavior of micellar fluids. Soc. Petroleum Eng. J. 22(6), 816–830 (1982)
14. Nelson, R.C.: Further studies on phase relationships in chemical flooding. In: Shah, D.O. (ed) Surface phenomena in enhanced oil recovery, Plenum Press, New York, p. 73–104 (1981)
15. Szabo, M.T.: An evaluation of water-soluble polymers For secondary oil recovery—Parts 1 and 2. SPE J. Petroleum Technol. (5), p. 553–570 (1979)
16. Tabary, R., et al.: Design of a surfactant/polymer process in a hard brine context: a case study applied to Bramberge reservoir. In: SPE EOR Conference at Oil and Gas West Asia. Society of Petroleum Engineers, Muscat (2012)
17. Shiau, B.J.B., et al.: Designing alcohol-free surfactant chemical flood for oil recovery. In: SPE EOR Conference at Oil & Gas West Asia. 2010, Society of Petroleum Engineers, Muscat (2010)
18. Bataweel, M.A.; Shivaprasad, A.Y.; Nasr-El-Din, H.A.: Low-tension polymer flooding using amphoteric surfactant in high salinity/high hardness and high temperature conditions in Sandstone Cores. In: SPE EOR Conference at Oil and Gas West Asia. Society of Petroleum Engineers, Muscat (2012)
19. Winsor, P.A.: Solvent properties of amphiphilic compounds. Butterworths Scientific Publications, London (1954)
20. Goodlett, G.O., et al.: The role of screening and laboratory flow studies in EOR process evaluation. In: SPE Rocky Mountain Regional Meeting. 1986 Copyright 1986, Society of Petroleum Engineers, Billings (1986)
21. Gao, P., et al.: Integrated evaluation of surfactant-polymer floods. In: SPE EOR Conference at Oil & Gas West Asia. 2010, Society of Petroleum Engineers, Muscat (2010)
22. Taber, J.J.; Martin, F.D.; Seright, R.S.: EOR screening criteria revisited Part 2: applications and impact of oil prices. SPE Reserv. Evaluation Eng. (3), p. 199–206 (1997)
23. Sheng, J.J.: (2011) Introduction, in modern chemical enhanced oil recovery, Chapt 1. Gulf Professional Publishing, Boston, p. 1–11 (2011)
24. Lake, L.W.: Enhanced oil recovery.: Englewood Cliffs, N.J. : Prentice Hall. p. 550 (1989)
25. Lenk, R.S.: A generalized flow theory. J. Appl. Polymer Sci. 11(7), p. 1033–1042 (1967)
26. Buchgraber, M., et al.: The displacement of viscous oil by associative polymer solutions. In: SPE Annual Technical Conference and Exhibition., Society of Petroleum Engineers: New Orleans (2009)
27. Unsal, E., et al.: Solution properties of mobility control Polymers. In: SPE Eastern Regional Meeting. 1977 Copyright 1977, American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., Pittsburgh (1977)
28. Abdul, A.; Gibson, T.; Rai, D.: Selection of surfactants for the removal of petroleum products from shallow sandy aquifers. Ground Water 28(6), p. 920–926 (1990)
29. Sheng, J.J.: Chapter 9—Surfactant-Polymer Flooding. In: Modern Chemical Enhanced Oil Recovery., Gulf Professional Publishing, Boston. p. 371–387 (2011)
30. Nasr-El-Din, H.A.; Hawkins, B.F.; Green, K.A.: Viscosity behavior of alkaline, surfactant, polyacrylamide solutions used for enhanced oil recovery. In: SPE International Symposium on Oilfield Chemistry. 1991, Anaheim (1991)
31. Zhenquan, L., et al.: A successful pilot of dilute surfactant-polymer flooding in shengli oilfield. In: SPE Improved Oil Recovery Symposium. 2012, Society of Petroleum Engineers: Tulsa (2012)
32. Yuan, S., et al.: Effects of important factors on Alkali/Surfactant/Polymer Flooding. In: SPE International Oil and Gas Conference and Exhibition in China. 1998 Copyright 1998, Society of Petroleum Engineers Inc.: Beijing (1998)