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Novel Nonylphenol Polyethoxylated Based Surfactants for Enhanced Oil Recovery for High-Mineralization Carbonate Reservoir

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Abstract: Surfactant flooding can mobilize trapped oil and change the wettability of the rock to be more hydrophilic, which increases the oil recovery factor. However, the selection of surfactants is difficult in the case of high salinity conditions. In this work, we synthesized three novel anionic-nonionic surfactants based on widely used nonionic surfactant nonylphenol polyethoxylated (NPEO) and evaluated their efficiencies for enhanced oil recovery (EOR) in high salinity water (20% NaCl). The modified surfactants showed a decrease in interfacial tension (IFT) up to 10 times compared with the nonionic precursor. All surfactants had changed the wettability of rock to be more hydrophilic according to contact angle measurements. The effectiveness of surfactants was proved by spontaneous imbibition experiments, in which the synthesized surfactants showed a better displacement efficiency and increased oil production by 1.5–2 times. Filtration experiments showed an increase in oil recovery factor by 2–2.5 times in comparison with the nonionic NPEO. These promising results prove that the synthesis of new surfactants by modifying NPEO is successful and indicate that these novel surfactants have a great potential for EOR in high salinity reservoirs.

Keywords: surfactants; surfactant-flooding; EOR; high-salinity; carbonate reservoirs

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1. Introduction

The use of enhanced oil recovery (EOR) methods can extend the production lifetime of mature oilfields in traditional production regions as the oil reservoir becomes depleted and more difficult to recover [1,2]. The use of novel surfactants created for individual reservoir conditions can significantly increase oil recovery and affect the wettability of rock and decrease the interfacial tension (IFT) between oil and water [3–8].

Over half of the world-known oil reserves are in carbonate reservoirs [9,10]; the majority of them are heterogeneous and have complicated pore structures. Additionally, most of these carbonate formations contain formation water with a high salinity [11]. Salinity has a significant impact on the surfactant performance and the formation of microemulsion. There are several works conducted to evaluate the effect of salt concentration on the solubility of surfactants in water [12,13]. The increase in salts content in the formation water decreases the solubility of surfactants. In microemulsions with high salt concentration, the IFT between the two phases (oil and water) rises as salt content increases [14]. Additionally, it was observed that wettability alteration from oil-wet/mixed-wet to water-wet becomes more difficult in very high salinity and vice versa [15].

Some laboratory screening and field applications of surfactants for carbonate reservoirs with high salinity water were conducted [16–18]. Many types of surfactants were reported, including anionic, cationic, and nonionic [19,20], as well as newly created ionic-nonionic, such as guerbet alkoxy carboxylate surfactant [21–23]. It was concluded that despite the fact that nonionic surfactants are the most salt tolerance, they are characterized by low activity in the oil/water interface. However, it is very important to reduce IFT to very low, even ultra-low values, to remobilize the residual oil. Therefore the surfactant should have a high interfacial activity for surfactant flooding [24]. Numerous studies are concerned with special ionic–nonionic surfactants, including modified alkoxy chains (nonionic) by ionic groups, such as alkyl aryl ethoxylated sulphonates and propoxylated sulfate or ethoxylated sulfates [25,26].

In order to improve the interfacial activity of nonionic surfactants, it is necessary to synthesize novel surfactants based on some nonionic surfactants with relatively high activity. Nonylphenol polyethoxylated (NPEO) are nonionic surfactants that are widely used in manufacturing antioxidants, lubricating oil additives, laundry and detergents, emulsifiers, and solubilizers [27], as well as in EOR applications [28]. They were tested under harsh conditions (high salinity and temperature) in conjunction with a cationic surfactant [29]. In addition, NPEO surfactant is stable at very high reservoir salinity [30].

Modification of NPEO by ionic groups can improve surfactant activity that helps to decrease the oil/water IFT and change wettability, and thus increasing oil recovery. Therefore, in this work, based on NPEO, we tried to synthesize anionic–nonionic surfactant that will be compatible with highly mineralized formation waters and show high interfacial activity. Three anionic modifications of nonionic surfactant NPEO were synthesized and investigated for high-mineralization conditions. In contrast to other works focusing on the study of separate surfactant properties, complex laboratory tests were also carried out in this work. The effectiveness of the new anionic-nonionic surfactants was evaluated by studying their ability to reduce IFT and alter the wettability of carbonate rock. Two main mechanisms of oil displacement were considered by long-term spontaneous imbibition and dynamic filtration experiments.

2. Experimental Section

2.1. Materials

A nonionic surfactant known as nonylphenol polyethoxylated with an average polyethoxylated length of 6 was used as a precursor (NP6EO). NP6EO with 98% active content was provided by Nizhnekamskneftekhim (Russia) petrochemical company. Maleic anhydride (99%) and sodium bisulfite (99%) were obtained from Acros Organics BVBA, Belgium. Succinic anhydride (99%) was purchased from Merck KGaA, Germany. Triethylamine (99.7%) was provided by Vecton company, Russia. Additionally, 1,3 propansultone (99%) was purchased from Alfa Aesar, USA. NaOH (98%) was provided by Dia.M, Russia. NaCl was obtained from JSC LenReactiv with a purity of >99.5 wt%. All chemicals were used without any further purification.

Core plugs are real limestone samples taken from the reservoir of the Bashkirian stage, located in the Tatar Republic. The core plugs were extracted, and then porosity and permeability were determined. For imbibition experiments, samples with porosity of 10–14% and permeability of 100–140 mD were used. For filtration experiments, cores with a porosity of 12–24% and permeability of 400–900 mD were chosen.

Crude oil was used after separation by centrifuge to remove water and solid residues. Oil properties were measured by tensiometer (Kruss SDT), gas chromatography (Agilent 7890B), and Stabinger viscometer (Anton Paar SVM-3000) (Table 1). In order to simulate high-salinity conditions, 20 wt% NaCl solution was used in all experiments.

2.2. Surfactant Synthesis

2.2.1. Synthesis of NP6EO–UOSN

NP6EO (12.36 g, 25.53 mmol) was weighed in a 100 mL round bottom flask and stirred at 60 °C for 30 min, followed by the addition of maleic anhydride (2.51 g, 25.61 mmol). Then, the temperature was increased to 90 °C. The reaction was monitored by TLC (using ethyl acetate as eluent). After 5 h, intermediate compound 1a was obtained as a yellowish, viscous material. An amount of 3.6 mL triethylamine was added dropwise into a 100 mL reaction flask containing 50 mL DCM (Dichloromethane), compound 1a (14.87 g), and 1,3 propansultone (3.14 g, 25.64 mmol). The mixture was stirred for 8 h at 25 °C. The yellow viscous material was obtained after solvent removal by a rotatory evaporator. The NP6EO–UOSN was used without any further purification.

Table 1. Crude oil properties.

Property	Value
Average alkane number	C8–C14
Viscosity at 20 °C	155.88 mPa·s
Density at 20 °C	0.932 g/cm^3
Oil–water interfacial tension at 20 °C	26.6 mN/m

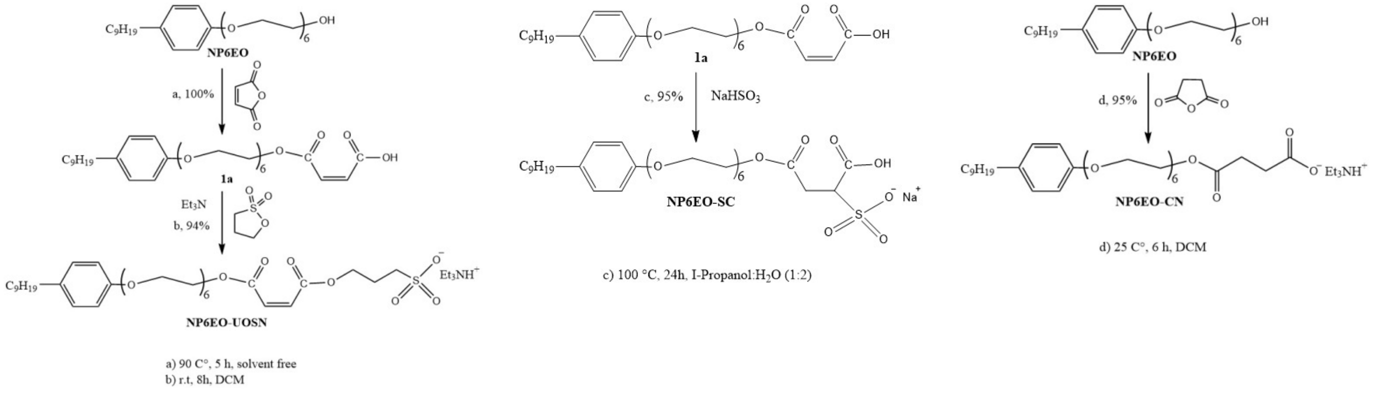
2.2.2. Synthesis of NP6EO–SC

NPEO6 (8.56 g, 14.70 mmol) and sodium bisulfite (1.6 g, 15.22 mmol) were loaded into a 250 mL flask connected to a water condenser containing 150 mL of aqueous isopropanol solution ($V_{\text{I-Propanol}}$:V_{water} = 1:2). The reagents were stirred for 24 h at 100 °C. The progress of the reaction was monitored by TLC (using ethyl acetate as eluent). After the completion of the reaction, the solvent was evaporated under reduced pressure in a rotary evaporator. The residual material was washed with hexane, then dried under vacuum in a rotary evaporator to obtain pale yellow viscous material NP6EO–SC.

2.2.3. Synthesis of NP6EO–CN

NPEO6 (8.56 g, 17.68 mmol) and succinic anhydride (1.77 g, 17.70 mmol) were loaded into a 100 mL flask containing 40 mL of DCM (Dichloromethane), then 2.46 mL triethylamine was added with continuous stirring. The reaction was monitored by TLC (using acetone as eluent). The reaction was continued for 6 h at 25 °C. The yellow viscous material was obtained after solvent removal by a rotatory evaporator. The NP6EO–CN was used without any further purification.

All synthesis schemes are shown in Figure 1.



(**a**) (**b**) (**c**)

Figure 1. (**a**) Synthesis scheme of NP6EO–UOSN; (**b**) Synthesis scheme of NP6EO–SC; (**c**) Synthesis scheme of NP6EO–CN.

2.3. Evaluation of the Surfactants

2.3.1. Interfacial Tension (IFT) Measurements

In order to determine IFT, the spinning drop method (Kruss SDT tensiometer) was used. This allows the estimation of IFT in a wide range of values from high 2×10^3 mN/m to ultralow 10^{-6} mN/m. The tensiometer software was used to calculate IFT based on the rotation speed, phase densities, and the radius of the stretched drop. All measurements were performed at 20 °C with a surfactant concentration of 0.3%.

2.3.2. CMC Determination

In order to find the optimal concentration of these surfactants, different surfactant concentrations were tested to find out their ability to decrease oil–water IFT [31–33]. The first derivative plotted from surfactant IFT data gave an indication of the critical concentration of forming micelles (CMC). Six different concentrations including 0.025%, 0.05%, 0.1%, 0.2%, 0.3%, 0.4%, and 0.5% were selected for all the surfactants. Surfactant solutions were prepared with water and 20% of NaCl.

2.3.3. Wettability Alteration

The contact angle method is one of the main criteria for evaluating the wetting ability of surfactants. The experiments were carried out using a Dataphysics OCA 15ES device under room conditions.

Core samples were aged in crude oil for 30 days before contact angle measurement. After aging, the surface of core samples was soaked with filter paper to remove excess oil, and the contact angle was measured. One of the carbonate core samples was chosen as the initial measurement by model water, which was used for the subsequent comparison with the action of surfactant formulation. Other core samples were placed in the prepared surfactant solution for 4 and 24 h, followed by dosing a drop of model water on the surface and measuring the contact angle.

2.3.4. Amott Cells

For imbibition experiments, surfactants, on the one hand, can increase the hydrophilicity of the rock, thereby reducing the adhesion forces of the oil to displace it; on the other hand, they can reduce the capillary force that mostly behaves as resistance for the oil displacement process.

In order to create initial oil saturation, core samples (Table A2 in Appendix B) with residual water saturation were loaded into a core holder and re-saturated by paraffin (2 pore volume injection) at 24 °C. Paraffin was then displaced with oil (3 pore volume injection) at a linear velocity of 5 m/day. The core samples were then taken out and loaded into a container with crude oil and aged for 30 days at reservoir temperature. After aging, the oil on the surface of cores was cleaned with filter paper for imbibition experiments in Ammot cells. The imbibition process was monitored for 600 h. The oil recovery factor in Ammot cell (ORF_{Ammott}) (1) was calculated by Equation (1):

$$ORF_{Ammott} = V_{dio}/V_{io}, \quad (1)$$

where V_{dio} is the volume of displaced oil, and V_{io} is the volume of initial oil in core samples. Four surfactants, i.e., NP6EO, NP6EO–CN, NP6EO–UOSN, and NP6EO–SC, were tested for imbibition experiments. The surfactant solutions (0.3 wt%) were prepared with 20% sodium chloride water.

2.3.5. Filtration Experiments

The schematic of the filtration setup is shown in Figure 2. Experiments were carried out using real carbonate cores (Table A1 in Appendix A) under reservoir pressure and temperature, i.e., 50 bar and 25 °C. Overburden pressure was 30 bar higher than reservoir pressure to simulate rock pressure and prevent crossflows. Fluids were injected through a piston cylinder using a plunger hydraulic pump with an accuracy of 0.001 mL/min. The reservoir pressure was maintained by a piston-type back pressure regulator with a needle valve. The inlet and outlet pressures of the core holder, as well as the differential pressure, were measured using highly sensitive digital pressure transducers (measurement accuracy 0.1%). Pressure data were continuously recorded online by a computer.

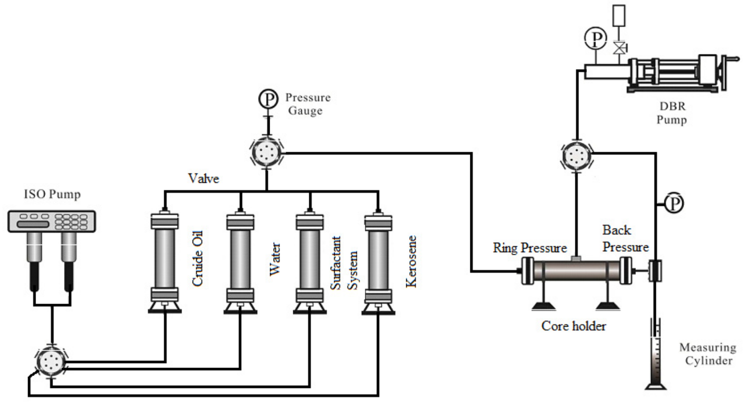


Figure 2. Schematic diagram of water flooding and surfactant flooding experiments.

The experiment was carried out in three stages:

First, cores were saturated with model water (20 wt% NaCl solution), and the absolute water permeability was measured. Then cores were saturated with kerosene in a semipermeable membrane to obtain an irreducible water saturation.

Secondly, kerosene was pumped into cores to create reservoir pressure. The cores were then saturated with crude oil (about 4 pore volume (PV) injection) to create initial oil saturation. The injection flow rate was 0.2 mL/min. Saturated cores were aged for 16 h in the filtration unit under reservoir conditions.

Finally, the cores were displaced by model water (0.2 mL/min) until 100% water cut. Volumes of displaced fluids at the outlet of the core holder were recorded every 0.2 PV. Filtration continued until 100% water was cut at the outlet but not less than 5 PV. Oil recovery factor (ORF), water cut, and changes in the injectivity of the core were calculated.

ORF and initial injectivity (I_{w1}) were calculated by Equations (2) and (3), respectively:

$$ORF = V_{do}/V_{io} \tag{2}$$

$$I_{w1} = q \cdot \mu_w \cdot L/\Delta P_1 \cdot k_w \tag{3}$$

where V_{do} is the volume of displaced oil, V_{io} is the volume of initial oil in core samples, q is the volumetric flow rate of model water, μ_w is the viscosity of model water, L is the length of the core column, ΔP_1 is the pressure drop after 100% water cut at the outlet at water displacement, and k_w is the absolute permeability by model water.

After oil displacement by water, 0.3 PV surfactant solution (0.3 wt%) was injected with a constant flow rate of 0.2 mL/min, followed by subsequent water injection (0.2 mL/min) until 100% water was cut at the outlet but not less than 5 PV. Additional oil recovery factor ($ORFA$) and water injectivity parameter after surfactant treatment (I_{w2}) were determined by Equations (4) and (5), respectively:

$$ORFA = V_{ado}/V_{io} \tag{4}$$

$$I_{w2} = q \cdot \mu_B \cdot L/\Delta P_2 \cdot k_w \tag{5}$$

where V_{aod} is the volume of additional displaced oil, and ΔP_2 is the pressure drop after 100% water cut at the outlet after surfactant treatment.

The change in injectivity was estimated as injectivity parameter (I_{ch}) by Equation (6):

$$I_{ch} = I_{w2}/I_{w1} \tag{6}$$

In order to highlight the effect of surfactant treatment from the total oil displacement, the coefficient of additionally displaced oil (K_{ORF}) was determined as shown in Equation (7):

$$K_{ORF} = ORFA/(ORF + ORFA) \tag{7}$$

3. Results and Discussion

3.1. IFT Measurements

The IFT between crude oil and distilled water was 25.78 mN/m. The addition of 20% NaCl into the water decreased oil/water IFT to 15.8 mN/m.

Figure 3 shows the dynamic IFT curves as a function of time, and the stabilized IFT values are shown in Table 2 NP6EO reduced the IFT to 0.16 mN/m, about 10 times lower than that reduced by salt water. A much more significant reduction in IFT values was obtained by all the synthesized surfactants in comparison to NP6EO. NP6EO–CN and NP6EO–UOSN showed the best ability to reduce IFT to 10 times less than that obtained by NP6EO, while NP6EO–SC reduced the IFT by only about three times lower in comparison to NP6EO. These lower IFT values mean that the modification of NP6EO by anionic groups was successful, which significantly improved the interfacial activity of NP6EO.

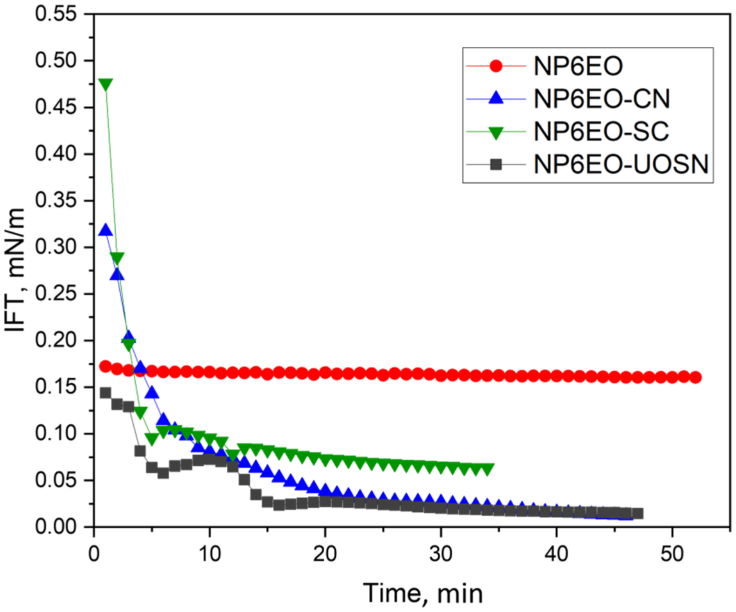


Figure 3. Dynamic interfacial tension between surfactant formulation and crude oil.

Table 2. IFT of surfactant formulations as well as the water used to prepare them.

Formulation	Solution	Stabilized IFT (mN/m)
NP6EO	20 wt% NaCl + 0.3 wt% NP6EO	0.16
NP6EO–CN	20 wt% NaCl + 0.3 wt% NP6EO–CN	0.014
NP6EO–SC	20 wt% NaCl + 0.3 wt% (NP6EO–SC)	0.06
NP6EO–UOSN	20 wt% NaCl + 0.3 wt% NP6EO–UOSN	0.015

3.2. CMC Determination

In the considered range of surfactant concentrations, the lowest IFT value for NP6EO occurred at 0.05% surfactant concentration. When the concentration was more than 0.05%, the IFT was increased rather than decreased or stayed constant. This phenomenon may be related to a variation in the distribution of surfactant molecules in the oil and water phases induced by increasing surfactant concentration [33]. For the synthesized surfactants, it can be clearly seen that the IFT values become more or less constant after reaching a surfactant concentration of 0.2 wt% (Figure 4), which means that this concentration range is optimal for further studies. In order to achieve a low IFT level for core flooding experiments, 0.3 wt% concentration was used for all the experiments.

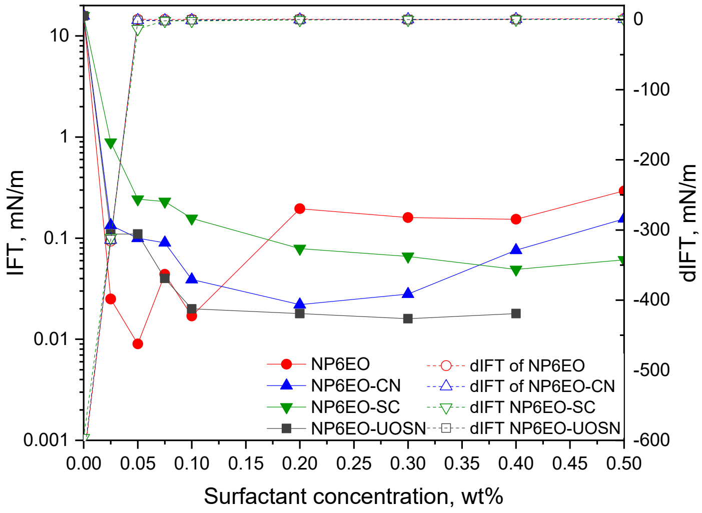


Figure 4. Interfacial tension of NP6EO, NP6EO–CN, NP6EO–SC, NP6EO–UOSN with different concentrations. Twenty percent NaCl and 1st derivative of IFT function (dIFT).

3.3. Alteration of Wettability

The initial contact angles as well as after 4 and 24 h of soaking in surfactant solution or model water (20% NaCl solution) were measured by a drop of 20% NaCl solution, and the results are shown in Figure 5 and Table 3. As we can see from Table 3, initially core is hydrophilic with the contact angles of about 70°. Aging in model water for 24 h almost did not change the contact angle. For all the surfactants, after 4 h aging, the contact angle was decreased by 4–7 times, and after 24 h of aging, the contact angles were equal to zero in two cases and practically zero in the other two. This means that these surfactants have a good wettability alteration ability, which is favorable for EOR. It is worth noting that NP6EO itself has a good ability to change wettability. It is not difficult for surfactants to change wettability, but it is not easy to reduce IFT to a low or even ultra-low level.

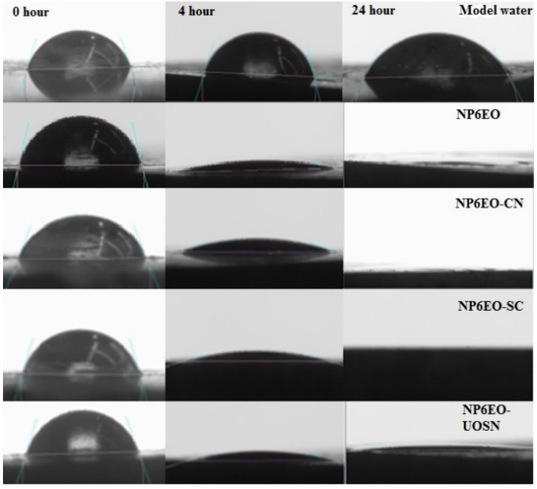


Figure 5. Changes in contact angle after 4 and 24 h aging of core in surfactant solutions.

Table 3. Results of contact angle study.

Formulation	Initial Contact Angle, °	Contact Angle after 4 h, °	Contact Angle after 24 h, °
Model water	71.4	74.7	61.8
NP6EO	76.2	10.1	0
NP6EO–CN	68.2	19.2	1.6
NP6EO–SC	74.1	14.8	0
NP6EO–UOSN	69.6	15.3	2.3

3.4. Amott Cells

The core samples were kept in the Amott cells with surfactant solution until there was no oil displacement within 2 days.The best result was shown by NP6EO–SC, while the worst was shown by the nonionic precursor NP6EO (Figure 6). In general, the synthesized surfactants showed the best of ORF_{Amott} value, increasing it by 1.4 to 2.3 times. NP6EO–SC increased ORF_{Amott} value 2.3 times, NP6EO–CN 2 times, and NP6EO–UOSN 1.4 times in comparison with NP6EO. Moreover, the oil displacement speed of the synthesized surfactants during spontaneous imbibition is higher than that of NP6EO. It took 288 h to yield 50% of the recovered oil by NP6EO, while all synthesized surfactants yielded 50% of the recovered oil in 48 h. The spontaneous imbibition was also carried out using model water, which almost did not yield any oil during this time. During the imbibition process, the action of the surfactant can be summarized into two aspects. The first is the wettability change, which is a comprehensive result of changes in interfacial tension before oil and water, as well as between water and rock surface [17]. This makes it easier to displace oil. It can be considered as that surfactant significantly reduce the work performed that is required to overcome the adhesion of rock surface to oil, which can be written as $W = \delta_{ow}(1 - \cos\theta)$, where δ_{ow} is IFT between oil and water, and θ is contact angle. However, in Section 3.3, we found that there is no large difference in the wetting ability of these surfactants. Therefore, from this point of view, it can be inferred that wettability alteration might not be the main reason that these synthesized surfactants significantly improved the oil recovery in the imbibition process. In this case, IFT reduction might be the dominant reason. Nevertheless, NP6EO–CN and NP6EO–UOSN, which showed the lowest IFT values, did not give the highest oil recovery. On the one hand, this might be caused by the difference in core samples. On the other hand, this might be related to the complicated action of capillary force in the imbibition process in porous media. Capillary force can play both roles of driving force and resistance in real porous media in the imbibition process, depending on the distribution of oil and water as well as pore structure, etc. [17].

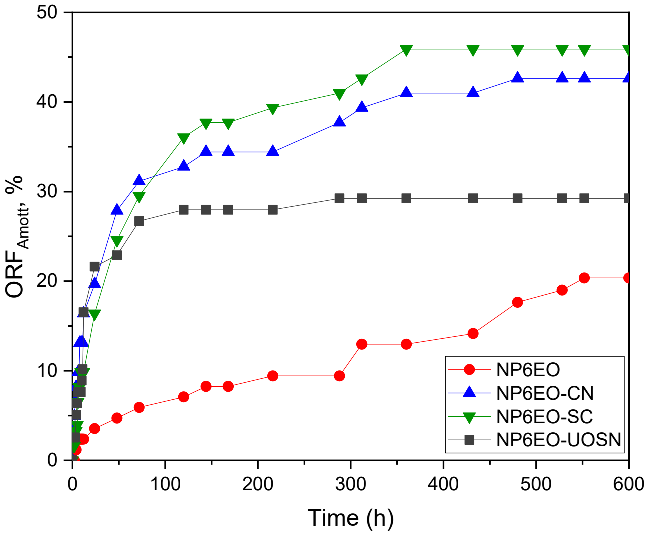


Figure 6. Oil recovery versus time during imbibition process.

3.5. Filtration Results

The experimental results are shown in Table 4 and Figures 7–10. According to the experimental data (Table 4), the highest oil displacement efficiency was achieved by surfactant NP6EO–UOSN. This surfactant yielded an *ORFA* of 16.08 vol%, which is 40 times higher than that achieved by NP6EO. This result is also confirmed by K_{ORF} 41.91 vol%. It should be noted that all the samples induced a significant decrease in the injectivity of the core samples, which is not good for those reservoirs where water injection is difficult.

Usually, this decrease in injectivity was caused by the in situ emulsification [33,34], which is favorable for those formations that have strong permeability heterogeneity.

Table 4. The results of experiments.

Value	*ORF*, %	*ORFA*, %	*ORF* + *ORFA*, %	K_{ORF}, %	I_{ch}
NP6EO	20.58	1.73	22.31	7.75	0.2384
NP6EO–CN	45.96	7.99	53.95	14.81	0.0157
NP6EO–UOSN	22.26	16.08	38.35	41.93	0.2105
NP6EO–SC	30.57	10.84	41.41	26.18	0.2392

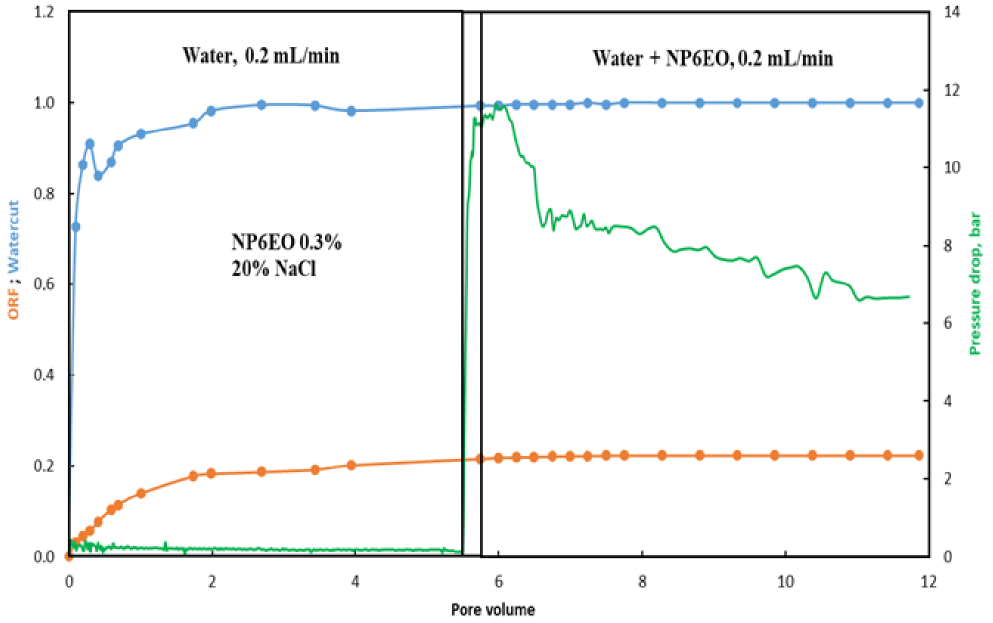


Figure 7. Oil displacement experiment of NP6EO flooding.

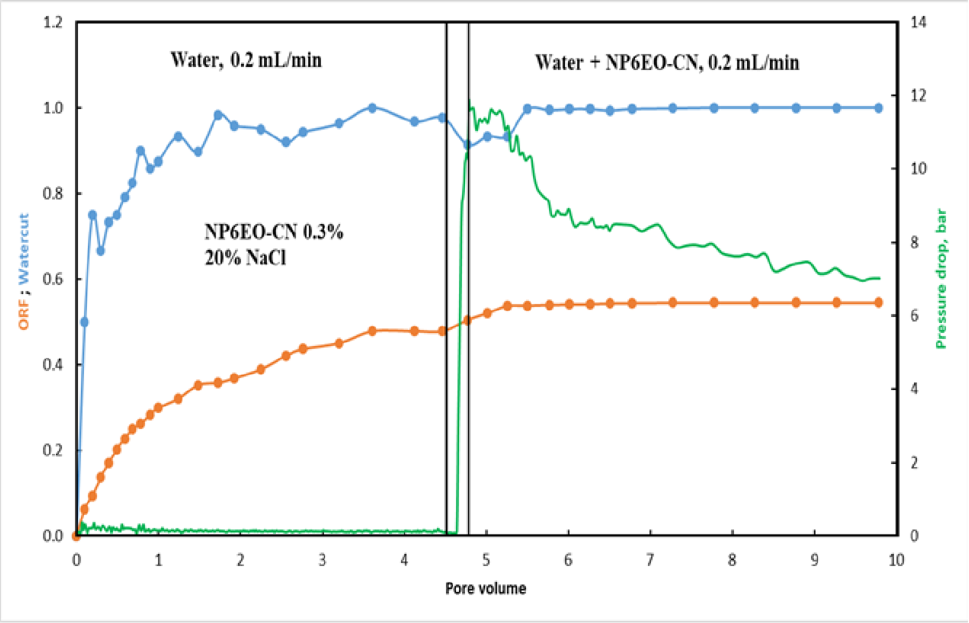


Figure 8. Oil displacement experiment of NP6EO–CN flooding.

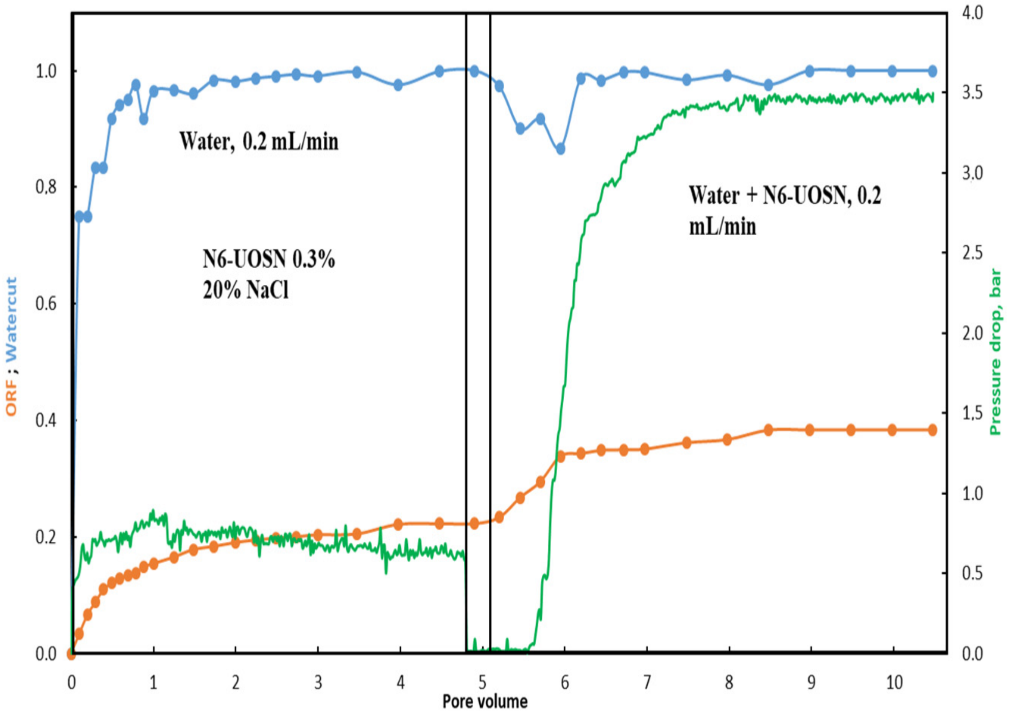


Figure 9. Oil displacement experiment of NP6EO–UOSN flooding.

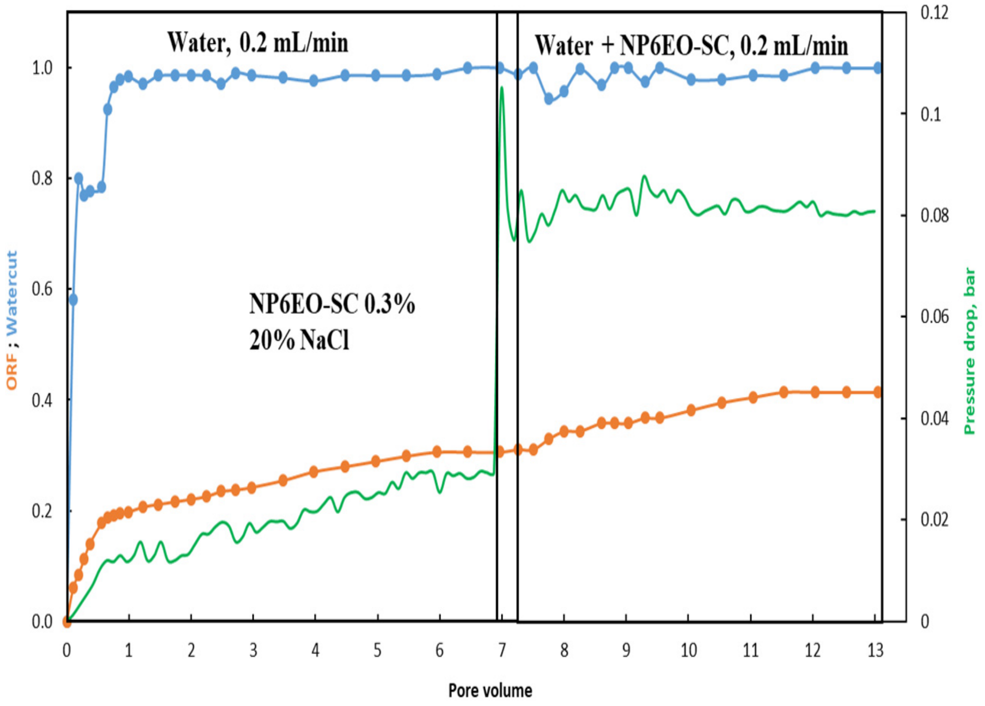


Figure 10. Oil displacement experiment of NP6EO–SC flooding.

In the filtration experiment with NP6EO (Figure 7), the *ORF* by model water was 20.58%. Surfactant flooding did not show a significant increase in ORFA. The ORFA was only 1.73% (the lowest in the four experiments). Moreover, the displacement lasted for 5.15 PV to achieve a 100% water cut. Moreover, the injection of NP6EO had a significant impact on decreasing injectivity (I_{ch} = 0.2384).

In the filtration experiment with NP6EO–CN (Figure 8), the *ORF* by model water was 45.96%, more than in other experiments. Surfactant flooding did not significantly increase ORFA (only 7.99%). The displacement process lasted for 5 PV to achieve a 100% water cut.

This sample showed the worst result in injectivity change parameter (I_{ch} = 0.0157). This can be attributed to the possible in situ formation of strong emulsion, which increased the pressure drop and decreased injectivity. Sometimes, an emulsion that is too strong is not favorable for the improvement of microscopic displacement efficiency [34].

In the filtration experiment with surfactant NP6EO–UOSN (Figure 9), the *ORF* by model water was 22.26%. Flooding with surfactant NP6EO–UOSN gave the highest ORFA (16.08%) among the four experiments. The displacement lasted for 5.27 PV to achieve a 100% water cut. This sample surfactant showed a moderate result in terms of injectivity change parameter (I_{ch} = 0.2105).

In the filtration experiment with surfactant NP6EO–SC (Figure 10), the *ORF* by model water was 30.57%. The ORFA was 10.84%. Oil displacement lasted for 4.28 PV. This sample showed the lowest impact on the injectivity change parameter (I_{ch} = 0.2392).

4. Conclusions

Three anionic–nonionic surfactants were synthesized based on nonionic NPEO for high-salinity conditions. Their effectiveness is proved and manifested in:

- Achieved 10 times lower IFT values than NP6EO precursor;
- Yielded a much higher displacement efficiency than the precursor in spontaneous imbibition experiments (NP6EO–SC gives the highest oil displacement efficiency);
- Yielded a higher additional oil recovery than NP6EO in the filtration experiments (NP6EO–UOSN is the most effective one).

In general, all synthesized surfactants showed higher interfacial activity in terms of IFT reduction and oil displacement in comparison with the precursor NP6EO, which proves the successful modification of NP6EO. These promising results imply that these synthesized new surfactants have great potential in EOR in high salinity reservoirs. This work not only provides new surfactant systems, which promotes the application of surfactant flooding to higher salinity conditions, but also gives some basic theories for synthesizing surfactant in terms of which anionic group should be used for high salinity conditions.

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Nomenclature

EOR	Enhanced oil recovery
IFT	Interfacial tension
CMC	Critical micelle concentration
ORF_{Ammott}	The oil recovery factor in Ammot cell
V_{dio}	Volume of displaced oil
V_{io}	Volume of initial oil in core samples
ORF	Oil recovery factor

I_{w1}	Initial injectivity
q	Volumetric flow
μ_w	Viscosity of water
L	Length of core
k_w	Absolute permeability by model water
ΔP_1	Pressure drop after full water cut at the outlet at water displacement
$ORFA$	Additional oil recovery factor
V_{aod}	Volume of additional displaced oil
V_{aod}	Volume of additional displaced oil
ΔP_2	Pressure drop after full water cut at the outlet aftersurfactant treatment
I_{w2}	Water injectivity parameter after surfactant treatment
I_{ch}	Injectivity parameter
K_{ORF}	Coefficient of additionally displaced oil

Appendix A

Table A1. Core for filtration experiment.

Surfactant	Core Samples	Diameter, mm	Length, mm	Porosity, %	Pore Volume, cm^3	Permeability, mD	Average Permeability, mD
NP6EO	1	299	500	19.55	6.86	997.2	554.69
	2	299	502	12.45	4.39	384.67	
NP6EO–CN	3	298.6	499.9	23.47	8.21	957.98	553.26
	4	298.4	500.8	11.59	4.06	389.15	
NP6EO–UOSN	5	297.8	500.7	24.51	8.54	909.26	583.82
	6	298.3	502.2	10.46	3.67	430.28	
NP6EO–SC	7	298.3	502.2	17.44	6.12	873.65	618.82
	8	297.8	502.6	24.37	8.53	479.17	

Appendix B

Table A2. Core for spontaneous imbibition experiment.

Surfactant	Core Samples	Diameter, mm	Length, mm	Volume, mL	Porosity, %	Pore Volume, cm^3	Permeability, mD
NP6EO	9	4.999	2.982	34.91	13.14	4.59	124.78
NP6EO–CN	10	5.009	2.986	35.08	12.37	4.34	131.34
NP6EO–UOSN	11	5.01	2.988	35.13	13.30	4.67	135.17
NP6EO–SC	12	5.019	2.987	35.17	9.68	3.40	148.44
Water	13	5.026	2.998	35.48	14.18	5.03	123.04

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