



Development and evaluation of foam-based conformance control for a high-salinity and high-temperature carbonate

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Received: 31 July 2017 / Accepted: 2 January 2018 / Published online: 20 January 2018
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Abstract

The extreme heterogeneity of carbonate reservoirs in the form of fracture corridors and super-permeability thief zones present challenges to the efficient sweep of oil in both secondary and tertiary recovery operations. In such reservoirs, conformance control is crucial to ensure injected water and any EOR chemicals optimally contact the remaining oil with minimal throughput. Foam-based conformance control is a relatively new technology especially its use for deep diversion in high-salinity and high-temperature conditions. In this work, a laboratory study was conducted to develop and evaluate a foam-based conformance control technology for application in a high-salinity and high-temperature carbonate. Foaming agents (surfactants) were first screened for their suitability with regard to reservoir temperature and salinity where properties such as foamability and foam stability were measured. The best performing surfactants were then used to study the foam-induced mobility reduction across a core composite. The experiments were conducted at reservoir conditions. Foam stability and decay were also investigated in those permeability reduction experiments. Brine and crude oil were injected after foam formation where observed pressure drops allowed quantification of foam stability and decay; hence, the sustainability of mobility reduction. Finally, the potential improvement in reservoir contact and hence oil recovery were examined by oil displacement experiments conducted in specially prepared heterogeneous composites. For the studied conditions of high salinity and high temperature, foaming agents of the amphoteric family as well as one manufacturer proprietary surfactants blend were found suitable in terms of salt tolerance and foam stability. Using the proprietary blend and without oil in core, the generated foam reduced fluids mobility by a factor of 12. The attained mobility reduction was lower in presence of oil but was still acceptable for flow diversion purposes. Using the proprietary blend and with oil in core, the generated foam reduced fluids mobility by a factor of 6 (compared to 12 without oil in core). Oil recovery improvement with foam placement was also found to be significant. These results demonstrate the potential of foams for carbonates with harsh salinity and temperature conditions.

Keywords Fluid diversion · Foam · Decay · Rheology · Recovery · Harsh conditions

Abbreviations

$D_{75\%}$	Time for 75% liquid drainage from foam
IFT	Interfacial tension
OOIC	Original oil in core
MRF	Mobility reduction factor
ΔP_{foam}	Pressure drop due to foam
$\Delta P_{\text{brine-nitrogen}}$	Pressure drop due to gas and brine
$\Delta P_{\text{brine-after-foam}}$	Pressure drop when brine is injected into foam
RF	Resistance factor
RRF	Residual resistance factor

SP	Surfactant–polymer
S_{wi}	Initial water saturation
$T_{\text{half-lie}}$	Time when half of foam decays
$T_{\text{total-decay}}$	Time when all foam decays

Introduction

One of the main issues associated with enhanced oil recovery (EOR) methods is poor volumetric sweep (Kuehne et al. 1990). This poor volumetric sweep is caused by reservoir heterogeneity and differences in fluid properties between the injectant and oil. Injected gas favorably channels through the high permeability streaks resulting in non-sweeping of remaining oil in the tighter rocks. In addition, the differences in fluids properties, viscosity and density, result in viscous

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fingering and gravity override (Chang et al. 1994; Rashid et al. 2013; Stephenson et al. 1993). Chemical methods might exhibit more favorable volumetric sweep due to polymer addition. However, due to chemicals associated costs and the need for their optimal utilization, in heterogeneous reservoirs even with polymer addition severe channeling need to be resolved (Wang et al. 2016; Alshehri et al. 2017). Therefore, in order to maximize the effectiveness of an EOR method, deep conformance control is essential.

Foam-based conformance control is a relatively new technology especially its use for deep diversion. Foams have been successfully applied in completion operations where acid is redirected by foam into less permeable zones thus improving the outcome of acid jobs considerably (Morphy et al. 1998). Foams have also been successfully applied as near wellbore treatments. In gas cap reservoirs, foams have been utilized to mitigate gas coning into production wells. Foam injected above the gas column suppresses the early breakthrough of gas and has been used as a GOR control technique (Dalland and Hanssen 1999; Krause et al. 1992). Production wells were also shown to be responsive to foam treatment by exhibiting a marked reduction in water-cut. The beneficial effects of foam treatment were shown to be caused by its relative permeability and lasted for upwards of 3 months in the treated wells (Zhdanov et al. 1996). Waterflooding control by foam has also been reported in the literature but has been performed mostly in the former Soviet Union. Water injection profile was shown to improve substantially after foam injection. Two field cases that demonstrated such injection conformance control were reported in the Russian literature as summarized by Zhdanov et al. (1996). Foams application for EOR operations has been continuously claimed as successful and essential. According to Ma et al. (2012), foam has been found as an essential aid for gas-based EOR due to its ability to decrease gas relative permeability by trapping the gas bubbles in porous media. These trapped bubbles increase the gas effective viscosity resulting in stability in the displacement process (Zhang et al. 2011). Foam also improves volumetric sweep by decreasing the mobility of the injected fluids in fracture corridors and high permeability zones which allows for diverting these fluids to sweep the remaining hydrocarbons in the lower permeability zones (Ma et al. 2012). In addition, the presence of surfactants in the foam contributes to the reduction of interfacial tension between the displacing and displaced fluid (Farajzadeh et al. 2009). In the area of CO₂ enhanced oil recovery, foams have achieved a lot of success in improving the sweep efficiency of the CO₂ plume thus leading to higher oil recovery. This was observed in pure CO₂ injection (Kleinsteiber 1990) as well as in water-alternating-gas (WAG) injection (Attanucci et al. 1993). In CO₂ sequestration, the use of foams has also been suggested

Table 1 Composition of brine

Ion	Concentration (mg/L)
Bicarbonate	142
Calcium	616
Chloride	30,864
Magnesium	2211
Potassium	694
Sodium	18,217
Sulfate	4483
TDS	56,933

Table 2 Fluid properties

Fluid	25 °C		90 °C	
	Density (g/cc)	Viscosity (cP)	Density (g/cc)	Viscosity (cP)
Seawater	1.03852	1.18	1.0121	.291
Oil	.88202	19.2	.8361	2.817

to significantly improve CO₂ storage efficiency (Vitoonkijvanich et al. 2015).

Nevertheless, in harsh reservoir conditions of high temperature and water salinity foam application, especially for deep diversion, is a challenge. In this work, we investigate the potential of foam-based conformance for high-temperature and high-salinity carbonates. We evaluate different foaming agents. Stability tests and dynamic bulk foam experiments provided the means to identify suitable foaming agents. The selection was based on several key parameters including foam height, foam half-life, liquid drainage and foam decay time. The selected foaming agents were then used to perform different core flooding experiments to evaluate foam mobility reduction capacity and demonstrate the potential increase in oil recovery.

Experimental materials

Brine

The main brine used in the make-up of the foams is the Arabian Sea brine with a total dissolved solid content of 57,000 ppm. The detailed salt composition is given in Table 1. This same brine was used in the water flood as well as in the formulation of the surfactant–polymer (SP) slug.

Oil

The oil used in all experiments is a light Middle Eastern dead crude. Properties of this crude are shown in Table 2.

Gas

The gas used for foam generation is nitrogen with 99% purity.

Foaming agents

Six surfactants were screened as foaming agents covering a range of surfactant families. Among them were an amphoteric surfactant, two anionic surfactants, an amine oxide surfactant and two proprietary blends. Those selective batches of surfactants were received from different manufacturers and have been identified as potential for harsh temperature and salinity conditions.

Surfactant–polymer slug

A surfactant polymer (SP) slug comprising of an amphoteric surfactant and a sulfonated hydrolyzed polyacrylamide was used in the oil displacement experiments. The potential of this SP slug was previously demonstrated for harsh temperature and salinity conditions (Han et al. 2012, 2013, 2014; Zhou et al. 2012; Fuseni et al. 2013; Wang et al. 2015).

Experimental methods

Dynamic foam analysis

To study the characteristics of foams generated with the different foaming agents, we used a dynamic foam analyzer. The schematic of the foam analyzer is shown in Fig. 1. Surfactant solutions were prepared at concentrations of .5 wt%. The tests were conducted at a temperature of 90 °C. For which, a bath was used; it was set at 90 °C and circulated until temperature stabilized. For each experiment, a 20 ml surfactant solution was placed in the glass cell. Then,

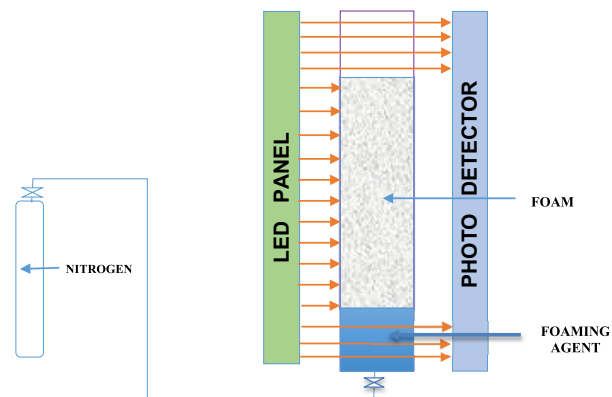


Fig. 1 Schematic of the dynamic foam analyzer

nitrogen was purged through a 3 micron silicon frit for 10 s, to create the foam. Once foam generation was complete, properties such as foam height, liquid drainage, half-life, decay time and density were recorded by the dynamic foam analyzer.

Foam rheometry

Bulk foam viscosity measurements were undertaken in order to correlate the foam performance obtained by the dynamic foam analyzer against direct foam rheology. The foam rheometer schematic is shown in Fig. 2. The foam rheometer is based on the capillary tube method where the generated foam flows through the loop and the measured pressure drop is used to calculate the foam viscosity. The foaming agent and gas are loaded into two cylinders connected to a pump. The system including the loop is then vacuumed and heated to the test temperature (90 °C). The foaming agent is then loaded into the loop followed by the nitrogen gas. The foam generation is then started and viscosities are subsequently measured.

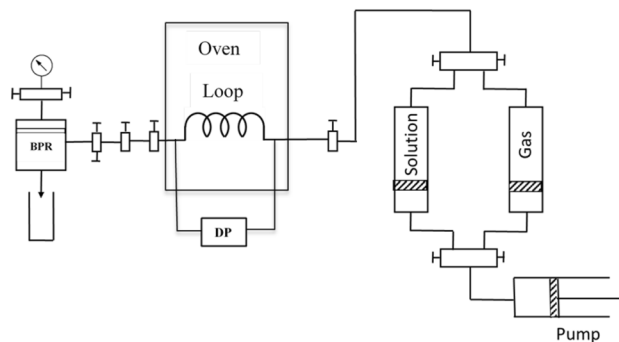


Fig. 2 Schematic of the foam rheometer

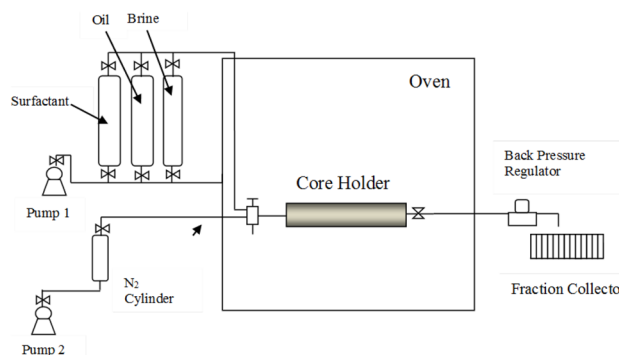


Fig. 3 Schematic of the core flooding system

Mobility reduction corefloods

To investigate the effectiveness of foam slugs in reducing the fluid mobility through a rock a set of coreflooding experiments were performed. The coreflooding equipment shown in Fig. 3 was utilized in the experiment. This is a modification of a conventional coreflood equipment to include a pressurized nitrogen cylinder and a gas injection pump. A core composite selected from a Middle Eastern carbonate reservoir was saturated with brine and mounted into the coreholder which was then brought to a temperature of 90 °C and a pressure of 2500 psi. Brine was injected through the composite to estimate brine permeability. Then, nitrogen and brine were simultaneously injected into the core and the base pressure drop across the core was recorded. Later, brine was injected until the core was restored to the original state as demonstrated by a restored pressure drop for brine. The foaming solution and nitrogen was then injected simultaneously until pressure stabilized. This was repeated for various foam qualities ranging from 60 to 90%. The mobility reduction factor defined as the ratio of pressure drop due to foam injection to the pressure drop without foam was calculated for all the foam qualities studied. At the end of each experimental phase, brine alone was re-injected into the core composite and pressure response recorded. This was done for each of the foam qualities in order to study the stability and decay of the foam slug after continuation of water flooding. Finally, to study the effect of oil on foam mobility reduction, oil was injected into the core and simultaneous injection of nitrogen and the foaming solution was carried out again. Changes in the observed pressure drop due to oil presence, hence attained mobility reductions, were also recorded.



Fig. 4 Heterogeneous core preparation

Table 3 Properties of screened foaming agents with crude oil at 90 °C

Surfactant	H_{max} (mm)	H_{60s} (mm)	$T_{50\%-decay}$ (s)	$t_{90\% decay}$ (s)	t_{10mm} (s)
Anionic-1	138	51.6	49.6	88.0	97.6
Anionic-2	156.6	52.8	48.2	80.0	84.8
Amphoteric	147.2	58.0	50.0	98.6	113.2
Blend-1	143.4	55.2	51.0	94.4	107.4
Blend-2	120.7	21.7	40.4	65.7	67.1
Amine oxide	132.4	13.3	28.8	60.3	62.3

Oil recovery corefloods

Oil displacement experiments were conducted to study the effect of foam placement on oil recovery in heterogeneous reservoirs. The same coreflooding equipment (Fig. 3) was utilized. A specially prepared heterogeneous composite core was used. Two core plugs from a carbonate reservoir with varying permeabilities (284 and 755 mD) were selected to create the heterogeneous composite. Each 1-1/2 inch core plug was sliced into two halves. A core plug was made by epoxying one half of the more permeable core to the other half of the less permeable core. The resulting core plug was saturated with brine and then displaced with dead crude to establish initial water saturation (S_{wi}). The two cores were then aged for a week. The composite core (Fig. 4) was then mounted into the coreholder and readied for the coreflood. Synthetic sea brine was used to water flood the heterogeneous core at 90 °C and 2450 psi. The flood rate was .5 cc/min, and effluents were collected in centrifuge tubes. After no more oil was produced from the water flood, .4 PV of an SP slug was injected into the core followed by chase brine. The brine injection was continued until no more oil was produced. Later, .3 PV of a 70% quality foam was placed. A second SP flood of similar slug size (.4 PV) was then injected and chased with brine. Additional oil production was observed and recorded until no more oil was produced.

Results and discussion

Foaming agents screening

The Dynamic Foam Analyzer enabled a quick and efficient screening of foaming agents by generating bulk foam and recording foam generation and its decay. All foaming agents were subjected to the exact same testing conditions of temperature and test procedures. Bulk foam properties were studied for each foaming agent. Table 3 summarizes key properties of the foams formed using the various foaming agents. From the results, we note that the amphoteric surfactant and proprietary Blend-1 demonstrated the best performance in terms of both foam strength and stability. The worst performance was obtained with the amine oxide.

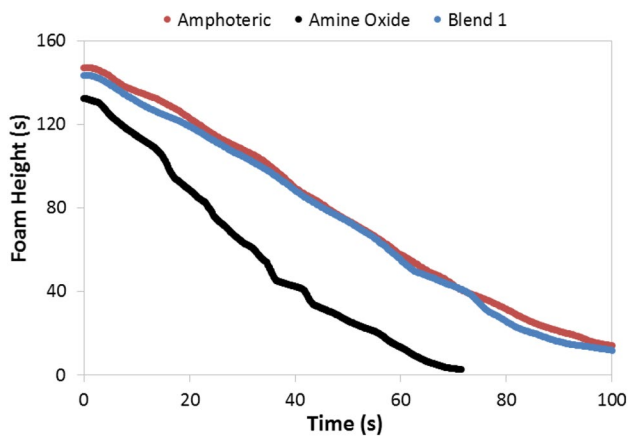


Fig. 5 Foam decay curves at 90 °C in the presence of oil for foams generated using the amphoteric, amine oxide and Blend-1 surfactants

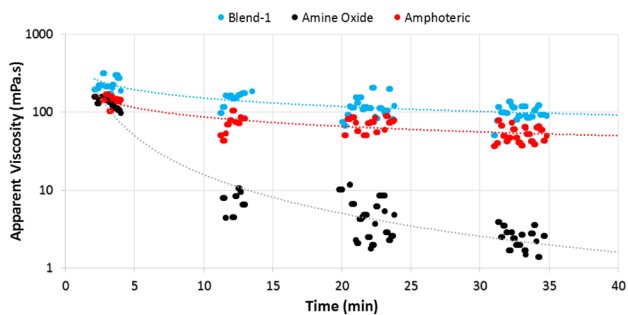


Fig. 6 Bulk viscosities of foams generated using Blend-1, amine oxide and amphoteric surfactants

Figure 5 illustrates the foam decay curves for those three foaming agents. Note the faster decay of the foam generated using amine oxide. Due to the relative shortness of those experiments (less than 2 min, refer to Fig. 5), we believe this faster decay cannot be explained based on chemical instabilities. In addition, due to the relatively minute amount of oil used in such experiments and the expected Winsor Type-II(-) phase behavior of the system, this faster decay cannot be explained based on higher partitioning into oil hence consumption of the foaming agent. Accordingly, we believe this faster decay is due to the amine oxide system being more susceptible to oil spreading than the other two surfactants. Basically, in the amine oxide case, the oil quickly penetrates the foam lamellas, spreads at the gas/liquid interface and causes its early decay. Such effects, as suggested by Novosad et al. (1989), depend mainly on the surfactant type.

Foam viscosity

To validate the suitability of the foam analysis as a screening tool, we compare the results against rheological behavior

measured for selected foams. The two foamers with the best performance (Blend-1, amphoteric) along the poor performer (amine oxide) were selected. Figure 6 show viscosities as a function of time for the different foams. It is worth noting that the rheometry program focuses on the stability of the foams rather its non-Newtonian behavior. Accordingly, the program consists of sporadic flow cycles of the generated foam. From the results, all foams initially exhibit high viscosities as suggested by the foam heights obtained with the dynamic analyzer (refer to Fig. 5). In terms of stability, however, for the poor performer (amine oxide), the high viscosity deteriorate significantly which is consistent with the foam decay results (refer to Fig. 5). The amine oxide surfactant used here was found to be salt-tolerant, but must have decomposed at the high test temperature, as observed by (Olsen 1989). The test temperature of 90 °C was therefore likely to have caused decomposition and therefore foam deterioration leading to low viscosity with time as shown in Fig. 6.

Finally, the viscosity results suggest the foam generated with Blend-1 exhibits higher viscosities compared to that obtained with the amphoteric surfactant. To the contrary the dynamic analyzer suggested the foam generated with the amphoteric surfactant is similar if not slightly better (refer to Table 3 and Fig. 5).

Mobility reduction

Coreflooding experiments were designed to investigate the ability of the generated foam to reduce injected fluid mobility and hence the ability to divert flow. Experiments were conducted using the top two performing foaming agents (per dynamic foam analyzer screening results). Initially, core-floods at a preset quality (70%) with and without oil were performed. Mobility reduction factors (MRF) were calculated based on pressure data:

$$\text{MRF} = \Delta P_{\text{foam}} / \Delta P_{2\text{-phase}} \quad (1)$$

where ΔP_{foam} represents the stabilized pressure drop due to foam formation, and $\Delta P_{2\text{-phase}}$ is the pressure drop observed when only brine and gas without any foaming agent is flowing through the porous medium. The results are shown in Table 4. Without oil, the amphoteric surfactant showed much better performance (i.e. higher mobility reduction). In other words, compared to bulk results (refer to Fig. 6), the foams behavior in porous media resulted in rheological properties that are different to these observed in bulk. As suggested and demonstrated by Mozaffari et al. (2015 and 2017), the use of micro- and nano-fluidic devices offer opportunities to bridge such gap in rheological studies. Nonetheless, with oil

Table 4 Mobility reduction factors of selected foaming agents with and without oil

Surfactant	Quality (%)	Without oil			With oil		
		ΔP_{foam} (psi)	$\Delta P_{2\text{-phase}}$ (psi)	MRF	ΔP_{foam} (psi)	$\Delta P_{2\text{-phase}}$ (psi)	MRF
Blend-1	70	14.2 ± .071	1.186 ± .006	12.0 ± .120	8.08 ± .040	1.186 ± .006	6.8 ± .068
Amphoteric	70	10.85 ± .054	.37 ± .002	29.3 ± .295	1.48 ± .007	.37 ± .002	4.0 ± .040

Table 5 Mobility reduction factors of selected foaming agent at different foam qualities

Surfactant	Quality (%)	ΔP_{foam} (psi)	$\Delta P_{2\text{-phase}}$ (psi)	ΔP_{brine} (psi)	ΔP_{brine2} (psi)	MRF	RF	RRF (%)
Blend-1	60	12.1 ± .061	1.305 ± .007	.204 ± .001	11.7 ± .059	9.3 ± .093	59.3 ± .596	96.7 ± .972
	70	14.2 ± .071	1.186 ± .006	.204 ± .001	15.4 ± .077	12 ± .120	69.6 ± .700	108.5 ± 1.09
	80	12.4 ± .062	1.147 ± .006	.204 ± .001	11.1 ± .056	10.8 ± .109	60.8 ± .611	89.5 ± .900
	90	6.9 ± .035	1.035 ± .005	.204 ± .001	11.4 ± .057	6.7 ± .067	33.8 ± .340	165 ± 1.66

Blend-1 showed better performance. Thus, it was selected for further experiments without oil.

Using Blend-1, similar experiments were conducted but at varying foam qualities. In addition, a chase brine injection phase was conducted post foam injection to investigate the sustainability of mobility reduction. Besides the mobility reduction factor (Eq. 1), we also estimate the resistance factor:

$$RF = \Delta P_{\text{foam}} / \Delta P_{\text{brine}} \quad (2)$$

which represents the increase in pressure drop due to foam formation compared to the pressure drop observed when only brine flows through the porous medium (ΔP_{brine}). Finally, using the chase brine injection data, we estimate the residual resistance factor:

$$RRF = \Delta P_{\text{brine2}} / \Delta P_{\text{foam}} \quad (3)$$

which reflects the permanent mobility reduction retained and represents the pressure drop observed during the chase brine phase (ΔP_{brine2}) compared to the pressure drop observed during foam injection (ΔP_{foam}). Table 5 summarizes the results for the selected foaming agent (Blend-1). All results suggest that significant mobility reduction and resistance are established due to foam injection. The results also suggest that a foam quality of 70% is optimal. Accordingly, Blend-1 at this foam quality will be used in the oil displacement experiments.

Finally, the residual resistance results suggest that the effects of foam are not destroyed by the subsequent flow of chase water. Overall, to exception of the 90% foam quality, the residual resistance averaged around 100%. At a quality of 90%, the residual resistance was even much

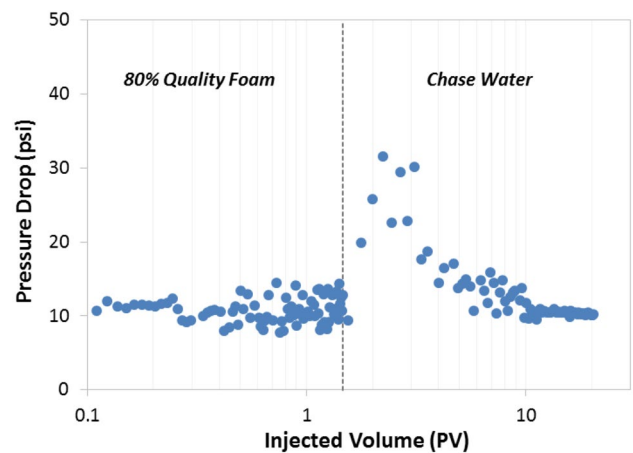


Fig. 7 Example mobility reduction experimental results: pressure drops observed during foam and chase water injection for the foam generated using Blend-1 at 80% quality

higher than 100%. A significant increase in pressure drop was observed during the chase water injection period with a 65% additional resistance (i.e., an RRF of 165%). This might be explained based on reduction of this foam quality toward more optimum qualities due to additional water injection. A second possible explanation is the regeneration of additional foam volume. Actually, in all cases, an initial significant increase in pressure drop is observed during the chase water injection phase. Example results at a foam quality of 80% are shown in Fig. 7. This rapid initial increase in pressure drop supports the possible reformation of foam lamella as water is injected into the core.

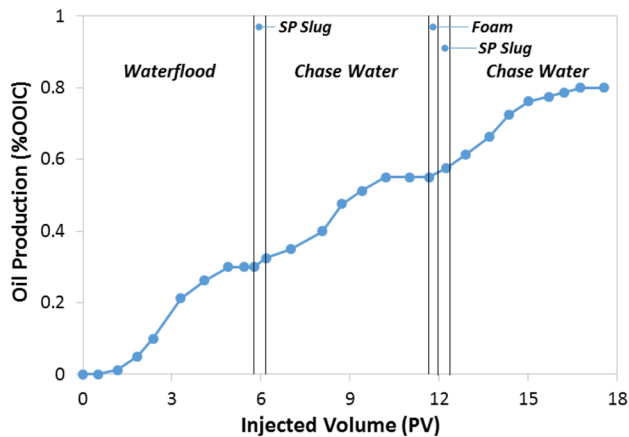


Fig. 8 Oil production results with sequential applications of various EOR processes in a specially prepared heterogeneous composite

Oil recovery

An oil displacement experiment in a specially prepared heterogeneous core composite (refer to “[Experimental methods](#)” section) was performed to investigate foam diversion potential. Initially, waterflooding was followed by SP flooding (with .4 PV of sloppy SP slug followed by chase brine) until no further oil was produced. Later, a foam slug (.3 PV with a 70% quality) was placed. A second SP flood was then conducted. Additional oil was produced (Fig. 8) by this second SP slug mainly due to foam placement and diversion effects. The oil recovery during the conventional waterflood was just below 30% original-oil-in-core (OOIC) mainly due to the heterogeneous nature of the core with the possibility of a fracture pathway. However, the SP solution was able to mobilize another 28% OOIC due to the combined action of mobility improvement and IFT reduction. Post foam placement, an SP flood of similar slug size produced further incremental oil of ~ 20% OOIC. Here, it is postulated that the foam slug blocked the more permeable section of the core and diverted the second SP slug into the less permeable section to recover more oil.

Conclusions

1. The use of a foam analyzer to screen surfactants based on foam heights, and their decay is an efficient method.
2. Rheometry adds additional insight to screening efforts specifically foam strengths. Foam decay results were found consistent with those obtained by the foam analyzer.
3. In coreflooding without oil presence, the foam generated with the amphoteric surfactant displayed much higher

mobility reduction compared to Blend-1 supporting foam analyzer over rheometric results.

4. Based on coreflooding, the effects of crude oil presence on foam mobility reduction was extremely significant for the amphoteric surfactant but was much less pronounced for Blend-1. This illustrates the importance of optimizing surfactant chemistry and formulation for oil applications.
5. The above results also suggest that both dynamic foam analysis and rheometry as screening tools can be improved by including tests with oil along the experimental protocols.
6. Based on core flooding results, for Blend-1 at least, the optimal foam quality was around 70% as it yielded the highest mobility reduction.
7. Water re-injection after foam placement did not result in significant losses of established foam resistance. Actually, mobility reduction at certain foam qualities increased post water re-injection; this increase was substantial for the foam with 90% initial quality. However, the initial foam quality yielding the highest mobility reduction remained to be 70%.
8. Oil recovery experiment conducted in specially prepared heterogeneous composites showed appreciable amounts of incremental oil production after foam placement.
9. In general, the results demonstrate the potential of foam-based conformance for reservoirs with harsh salinity and temperature conditions.

Acknowledgements The authors wish to thank Saudi Aramco for permission to publish this paper and EXPEC ARC management for resources to undertake this study.

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