

An Experimental Study on Optimization of SAG Process Utilizing Nonionic Surfactants and Sodium Lignosulfonate

Mahsa Moayedi, L.A. James, Maziyar Mahmoodi
Memorial University of Newfoundland

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ABSTRACT

Foam, produced during surfactant alternating gas (SAG) injection, reduces the mobility by increasing the displacement fluid (gas) viscosity. Surfactant generated foam has been shown to block high permeability zones and reduce the interfacial tension between the water and oil phases leading to increased recovery efficiency. This paper reports a comparative laboratory study of two non-ionic surfactants (Ivey-Sol 108 and TX-100) in a series of SAG tests. The interfacial tension between both of the surfactant solutions and the oil phase was measured and foam generation and stability was investigated. Coreflooding experiments were performed to examine the effect of surfactant concentration, water salinity, and injection scheme. Results show that injecting gas-surfactant-gas of high concentration TX-100 in low salinity brine yields the best recovery. Surfactant adsorption losses are a recognised challenge and were prevented through the addition of sodium lignosulfonate (SLS) as a sacrificial adsorption additive.

INTRODUCTION

Nonionic surfactants in surfactant alternating gas (SAG) injection may be better suited for reservoirs with high total dissolved solids since the ions in ionic surfactants can form precipitate phases causing the surfactant to become insoluble [1]. The idea of using surfactant induced foam for gas mobility control was first introduced by Bond and Helbrook [2]. Foam can increase oil recovery compared to water alternating gas (WAG) by increasing the displacing fluid (gas) viscosity and stabilizing the displacement, blocking high-permeability swept zones, and reducing the interfacial tension due to the presence of surfactant [3]. Foam can be created by alternating the surfactant and gas injection (SAG) or co-injection, of which SAG injection has several advantages over co-injection. In subsurface application, the pressure build-up during gas injection can be controlled by a specific injection pressure in the SAG process. SAG injection minimizes contact between water and gas in surface facilities, which is important when using acidic gases such as CO₂ [4]. It has been reported that alternating injection of a small amount of gas and liquid will improve the foam generation in the near-well region [5]. SAG has the potential to increase gas injectivity as water is displaced from the near-well region during gas injection, foam weakens, gas mobility rises and injectivity increases [6]. A major limitation to the application of foam is the stability of foam in oil reservoirs. Some studies report that the generated foam is destabilized by the oil phase. It has been suggested that foam stability depends on the composition of the oil phase and that the presence of light components is detrimental to foam stability [7]. Results from previous studies indicate that stable foam requires surfactant concentrations to be substantially above the critical micelle concentration (CMC) [8] and that foam stability is insensitive

to salinity when the surfactant concentration is above the CMC [2]. The objectives of this research are to examine and compare two non-ionic surfactants and the optimal SAG injectivity conditions for recovery efficiency.

EXPERIMENTAL PROCEDURE

The **interfacial tension (IFT)** between the oil phase and the surfactant solution at different concentrations in high salinity brine was measured by the Vinci IFT 700 apparatus at coreflooding experimental conditions of 500 psi (3450 kPa) and 25°C. **Foam stability tests** were carried out to measure the foam generation and stability according to ASTM D3601. **Coreflooding experiments** (Fig.1) using a 12 in (30.5 cm) Berea sandstone core (1.5 in (3.8 cm) diameter, 100 mD permeability and 20% porosity) was vacuum saturated using a synthetic brine (Table 1). The back pressure regulator was set to 500 psi (3450 kPa) to maintain system pressure and several PV of brine were injected into the core at a high flow rate (1 ml/min) until the amount of injected and produced water was the same and a stable pressure drop was observed along the core. The sample was then flooded with Hibernia crude oil (33.9 °API) at a low flow rate (0.03 ml/min) until connate water saturation was reached. One PV of brine was injected at the flow rate of 0.05 ml/min (~1 ft/day), as secondary waterflood. Nine experiments were performed with the same flow rate (~1 ft/day), various injection strategies, brine salinities, surfactant types (Table 2) and surfactant concentrations. Sodium lignosulfonate (SLS) (0.5 wt%) was added to the first water slug of experiments 8 and 9 as a sacrificial adsorption agent.

RESULTS AND DISCUSSIONS

Bottle tests: The foam generated from TX-100 was more stable than Ivey-sol 108 in the absence of oil (Fig.2). Surfactants at concentrations above their CMC generally increases foam generation and stability. The presence of oil significantly and detrimentally affects foam stability. The stability of foam for Ivey-sol 108 at 0.3 wt% > CMC and at lower brine salinity was significantly higher compared to at high salinity. TX-100 foam lasted longer simply because it had a higher initial foam height.

IFT tests: The IFT results show that the IFT between the high salinity brine and oil decreases with increasing surfactant concentration. Fig.3 shows the IFT between the oil and Ivey-sol 108 and TX-100 solutions in high salinity brine at various concentrations. The IFT for TX-100 is almost eight times smaller than that of Ivey-sol 108 at 0.3wt% above their respective CMCs as verified by Zubair et al. (2013) [9].

WAG vs. SAG: The effect of adding surfactant to the water cycle results in 9% more residual oil recovery comparing results from experiments 1 and 2 (Table 3) shown in Fig.4. Due to the presence of surfactant in the porous media prior to the second gas injection, foam generated in-situ can improve recovery during the second gas injection by increasing viscosity and reducing the mobility of gas.

Surfactant type and concentration: Four experiments were conducted using high salinity brine and TX-100 or Ivey-sol 108 at either CMC or 0.3wt% > CMC surfactant. The results show that residual oil recovery increases with surfactant concentration (Fig.5) since more stable foam is generated. At 0.3wt% > CMC surfactant concentration, TX-100 yielded 14% higher residual oil recovery compared to Ivey-sol 108 whereas at CMC, TX-100 yielded 6% higher recovery due to presence of more stable foam in porous media.

Salinity: Ivey-sol 108 at 0.3wt% > CMC in lower water salinity was shown to increase oil recovery by 10% in secondary waterflooding compared to higher salinity (Fig.6). Tang & Morrow [10] reported that during low salinity water injection, fines may be washed away resulting in the exposure of primary surfaces that are more water-wet, but during high salinity water injection fines retain their oil wet nature resulting in lower sweep efficiency. Lager et.al [11] explained that cation exchange between the mineral surface and invading brine causes higher oil recovery during low salinity water injection. The lower salinity water plus surfactant improved recovery of residual oil by 11% most likely due to the presence of more stable foam as we observed in the bottle tests (Fig.2).

Injection Scheme: The effect of starting with gas injection after secondary waterflooding was compared to surfactant injection in experiments 2 and 3. In the first cycle gas was more effective than surfactant due to water-wetness (Table 3) of our system. This can be explained considering the hysteresis effect of drainage and imbibition processes. Residual oil is primarily trapped in large pores of water-wet rock after waterflooding (imbibition) whereas gas injection is a drainage process thereby better sweeping the residual oil from the larger pores assuming no other viscous or gravity effects. Due to foam generation, injection of gas after the surfactant cycle was more efficient in improving recovery compared to the case without surfactant (hence no foam).

Sacrificial Adsorption Agent: Based on the results of previous studies [12] the IFTs of lignosulfonate solutions decreases with increasing lignosulfonate concentration while the IFTs of surfactant and lignosulfonate mixtures increase with increasing lignosulfonate concentration. Lower interfacial tension is favorable to generate more stable foam for lignosulfonate and surfactant mixtures [12]. Thus, the effect of sodium lignosulfonate (SLS) was examined by adding 0.5 wt% of SLS to the secondary waterflooding rather than using the mixture of lignosulfonate and surfactant. In our experiments the effluent was collected and based on the significant change in color of the water phase, it was concluded that the majority of SLS had been adsorbed to the rock surface preventing surfactant adsorption losses during the next cycles. Tsau et al. [13] reported similar results when lignosulfonate and surfactant CD1045 were injected into the Berea core in one cycle and the adsorption of surfactant was reduced by 24 to 60 (Fig.8). Experiment 9 shows the optimal injection scheme based on the results previously described. The secondary waterflooding with the addition of 0.5wt% SLS in low salinity brine was followed by a cycles of gas, a cycle of TX-100 at 0.3wt% > CMC surfactant concentration in low salinity brine followed by a final gas cycle. As anticipated the result showed the best recovery (84.5%) compared to previous experiments (Fig.9).

CONCLUSION

The experimental results indicate that TX-100 is superior to Ivey-sol 108 for reducing the IFT and producing foam. More stable and stronger foam can be generated using low salinity brine and concentrations of surfactant above CMC. The increased recovery is due to presence of more stable foam and stronger in the porous media. The addition of SLS to the secondary waterflooding can prevent surfactant adsorption onto the rock surface, therefore maintaining a higher concentration of surfactant leading to increased oil recovery.

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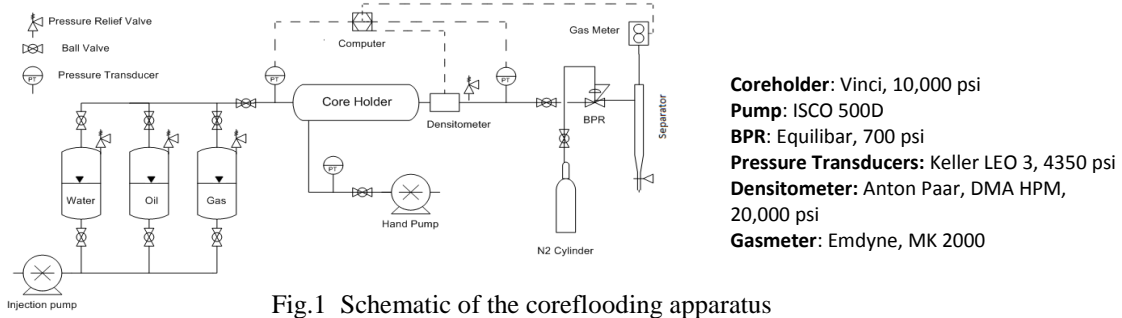


Fig.1 Schematic of the coreflooding apparatus

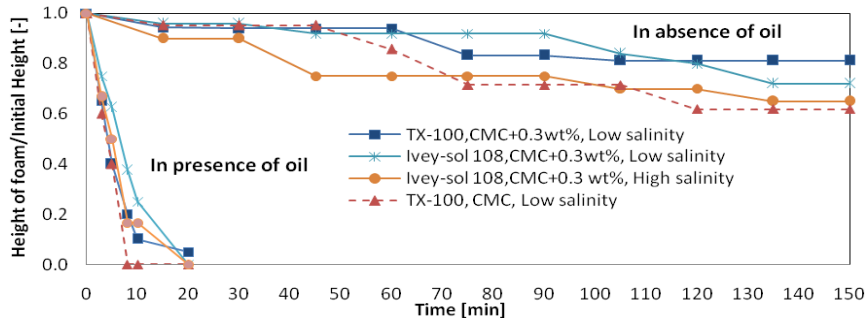


Fig. 2 Bottle test results. Foam relative height in absence or presence of 10 vol % oil for different surfactants at different concentrations and salinities.

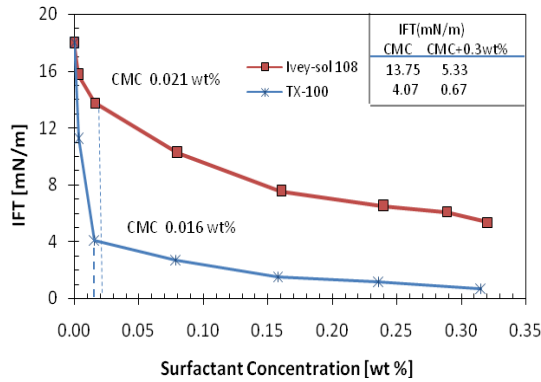


Fig. 3 IFT at different surfactant concentrations.

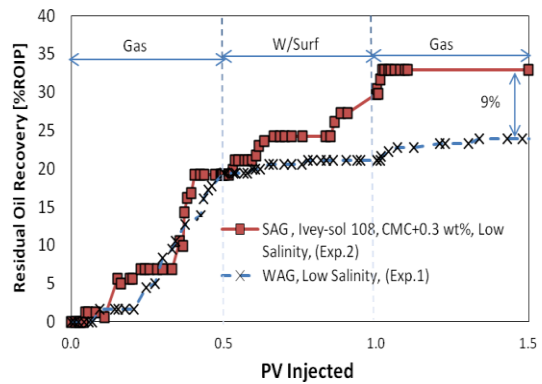


Fig. 4 Comparison of WAG and SAG injection

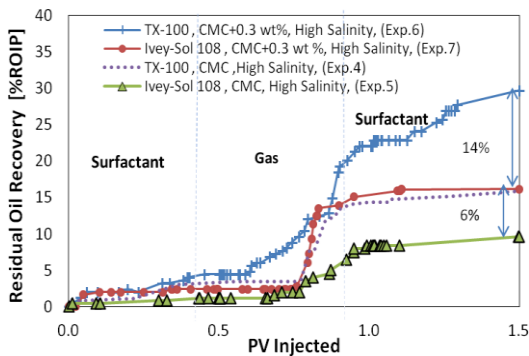


Fig. 5 Effect of surfactant types and concentration.

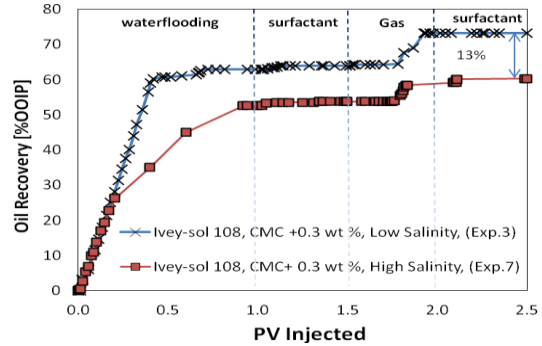


Fig. 6 Effect of salinity on total oil recovery.

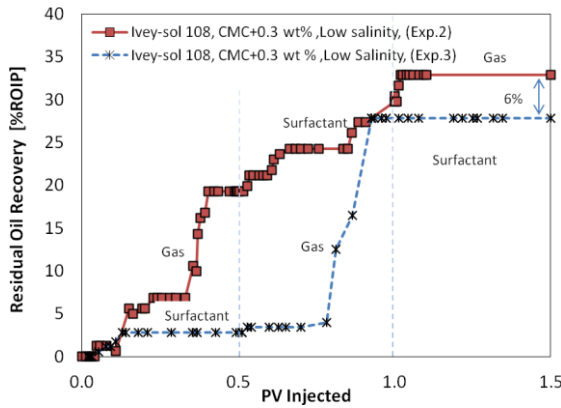


Fig. 7 Effect of injection scheme (starting with gas or surfactant) after secondary water flooding.

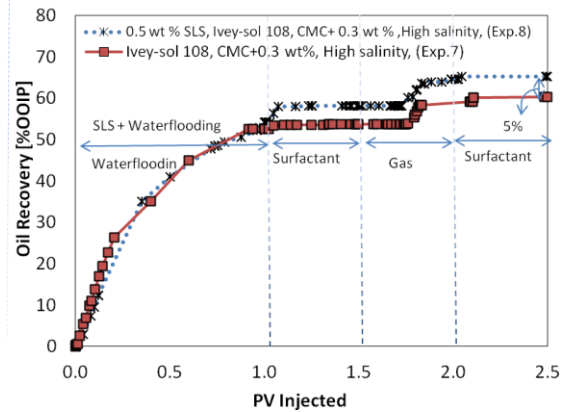


Fig.8 Effect of addition of SLS to the secondary waterflooding on total recovery.

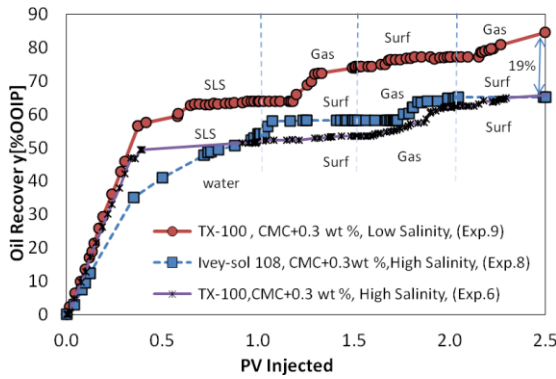


Fig. 9 Optimization of experiments (effect of adding SLS to secondary waterflooding, injection scheme of SLS/G/S/G, using low salinity and TX-100 at 0.3 wt % Above CMC) .

Table 1. Brine Compositions

Composition	Low Salinity Concentration (ppm)	High Salinity Concentration (ppm)
NaCl	5000	15000
Na ₂ SO ₄	500	1500
NaHCO ₃	500	1500
CaCl ₂	500	1500
KI	500	1500
Total Salinity (TDS)	7000 ppm	21000 ppm

Table 2. Surfactants and SLS properties

Chemical	CMC (wt%)	Density (g/ml)
Ivey-sol 108	0.021	1.030
Triton X-100	0.016	1.065
SLS	-	0.5 apparent

Table 3. Summary of the Experimental Runs

Experiment #	Injection Scheme	Brine Salinity ppm (TDS)	Surfactant Type	Surfactant Conc. (wt%)	IFT (mN/m)	Contact Angle (°)	N _c	S _{wc}	S _{or}	Waterflood Recovery [%OOIP]	Inc.Oil Recovery [%OOIP]	Total Recovery [%OOIP]	Recovery [%ROIP]
1	W-G-W-G	7000	-	-	14.3	34	3.0 x 10 ⁻⁷	0.31	0.26	63	9	72	24
2	W-G-S-G	7000	IV	0.321	4.7	41	10 x 10 ⁻⁷	0.36	0.23	64	12	76	33
3	W-S-G-S	7000	IV	0.321	4.7	41	10 x 10 ⁻⁷	0.32	0.25	63	10	73	27
4	W-S-G-S	21000	TX	0.016	4.1	61	1.8 x 10 ⁻⁶	0.21	0.38	52	8	60	16
5	W-S-G-S	21000	IV	0.021	13.8	50	3.9 x 10 ⁻⁷	0.25	0.36	52	5	57	10
6	W-S-G-S	21000	TX	0.316	0.7	89	2.6 x 10 ⁻⁴	0.27	0.36	51	15	66	30
7	W-S-G-S	21000	IV	0.321	5.3	58	1.2 x 10 ⁻⁶	0.23	0.36	53	7	60	16
8	SLS-S-G-S	21000	IV	0.321	5.3	58	1.2 x 10 ⁻⁶	0.25	0.34	54	11	65	24
9	SLS-G-S-G	7000	TX	0.316	0.4	71	2.5 x 10 ⁻⁵	0.33	0.24	64	21	85	57

W: water, S: surfactant, SLS: Sodium Lignosulfonate, G: gas, N_c: capillary number
 IV: Ivey-sol 108, TX: Triton X-100, IFT is measured between surfactant solution and oil.