052 FOAM PROPAGATION IN SNORRE RESERVOIR CORE — EFFECTS OF OIL SATURATION AND AGEING

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ABSTRACT

A series of foam floods was conducted in Snorre reservoir core at 90°C and 300 bar, at different oil saturations. The rate of foam propagation and the time required to reach the maximum attainable apparent foam viscosity depended strongly on oil saturation. Apparent foam viscosity decreased steeply at a "critical" oil saturation of 13 to 15%. Extremely high apparent foam viscosities, up to 1000 cP, were generated at miscible gas flood residual oil saturation (13%). Above the critical oil saturation, strong foam with apparent viscosities of about 200 cP were still formed, compared to apparent gas viscosities in the absence of surfactant of 0.5 to 0.7 cP. The effect of gas composition (Snorre field gas, methane, nitrogen) on foam performance was minor. Significant residual gas mobility reduction was observed during gas injection into the foam-filled core.

1. INTRODUCTION

Foams have been considered for mobility or profile control in gas injection IOR processes, for blocking and diverting using either conventional or gelled foams, and for controlling GOR at production wells. In a mobility control application, good foam stability to oil and low surfactant adsorption are essential, but moderate mobility reduction is sufficient. If foam is to be placed into swept (low oil saturation) zones to divert gas flow into unswept zones, a foam with intermediate or low stability to oil may be adequate, but high resistance to flow under an applied pressure gradient is required. A foam treatment to reduce GOR at production wells requires a foam with high flow resistance and good stability to oil; moderate or high adsorption levels may be acceptable for a near-wellbore treatment. Whatever the application, the foam has to propagate away from the wellbore in order to be effective.

Studies of foam propagation report varied results, but agree in concluding that foam propagation depends critically on injection strategy (1-4). Irani and Solomon (1) found that foam does not propagate during alternating injection of small surfactant slugs and CO₂ or during surfactant/CO₂ co-injection in an oil-free slim tube. The relatively small volume of injected surfactant solution did not propagate past the inlet section of the core, resulting in a high pressure gradient near the core inlet only. The authors conclude that gas and liquid do not move through the slim tube simultaneously during co-injection, but that foam forms where gas and surfactant contact each other. By contrast, a dual slug injection method consisting of a large slug of dilute surfactant solution followed by CO₂ resulted in effective foam propagation in the absence and presence of residual oil. Hudgins and Chung (3) found that foam generation and propagation depends on WAG ratio and injection sequence in an oil-free slim tube. At a residual oil saturation of 23%, foam was formed only when the surfactant slug was large enough to fill the slim tube, and foam was generated only in the tube outlet section. Hutchinson and co-workers (4) were able to generate steam foam in an oil-free slim tube by surfactant/steam co-injection. At an oil saturation of 12%, foam could be generated and propagated by alternating injection of surfactant and steam, but not by co-injection. Chou (2) was able to propagate foam at the injection rate in an oil-free, surfactant saturated core during surfactant/gas co-injection. When the core was not pre-saturated with surfactant, foam propagation was delayed more than can be accounted for by surfactant adsorption. Chou has presented mechanistic arguments to explain experimental data investigating the effects on foam formation and propagation of flow rate, pressure gradient, capillary

pressure, gas type (nitrogen or CO₂), surfactant concentration, foam quality, core length, foam strength, and injection mode, all in oil-free cores.

This paper summarizes foam propagation studies that were part of the design of foam treatments in the Snorre field in the northern North Sea. A producer treatment (5) was carried out in June 1996 with the purpose of reducing the GOR, which had risen to unacceptably high levels after early gas breakthrough during WAG injection. The WAG pilot (6,7) as well as laboratory (8-10) and simulation (10,11) studies towards the foam pilot have been described in detail elsewhere. An injector treatment (foam assisted WAG) is scheduled to start in the autumn of 1997.

2. EXPERIMENTAL

Foam experiments were conducted in a stacked sandstone core consisting of several plugs from the Snorre field (total length 59 cm, cross-section 11.4 cm², porosity 23.5%). The core holder allowed radial as well as axial overburden pressure to be applied for maximum capillary contact between core plugs. The brine was filtered (0.45 µm) synthetic sea water containing 3.5 wt% total dissolved solids at the following composition (in wt%): 2.366% NaCl, 0.0762% KCl, 0.154% CaCl₂·2H₂O, 1.087% MgCl₂·6H₂O, 0.0024% SrCl₂·6H₂O, 0.0201% NaHCO₃, 1.006% Na₂SO₄·10H₂O. Three gases were used: nitrogen (99.5 vol%), methane (99 vol%), and Snorre field gas (70 mol% methane, 13 mol% ethane, 9 mol% propane, 2.4 mol% each of n-butane and nitrogen, and some higher molecular weight hydrocarbons). Separator crude oil and gas were recombined to the composition of Snorre reservoir oil (GOR 109, B_o 1.35, at 90°C and 300 bar). The surfactant was a C₁₄₋₁₆ alpha olefin sulphonate (AOS). Some experiments were also run with a C₁₆AOS. All surfactant concentrations are %w/v active. Some fluid properties are listed in Table 1.

Table 1. Fluid properties at 90°C and 300 bar.

	Density (g/cm ³)	Viscosity (cP)
Synthetic sea water	1.003	0.36
Recombined Snorre crude oil	0.721	0.66
Snorre injection gas	0.262	0.0320
Methane	0.158	0.0219
Nitrogen	0.249	0.0279

The core was situated in a high pressure core holder in a thermostatted oven. Fluid injection was by displacement from floating piston vessels using HPLC pumps. During foam injection, gas and liquid streams were combined upstream of the core. No foam generator was used. System pressure was controlled by a gas dome type back pressure regulator (BPR). Pressure drops were recorded by a series of differential pressure transducers, a strip chart recorder, and an electronic data acquisition system. The core holder accommodated three pressure taps to measure pressure drops across the full length of the core, and across the two-thirds and one-third sections of core closest to the outlet.

Three sets of foam floods were run at different oil saturations: immiscible gas flood residual, miscible gas flood residual, and oil-free. Before each set of experiments, the core was cleaned by injecting alternating cycles of isopropanol and toluene, and saturated with brine. For experiments at S_{or}, the core was brought to S_{wi} (20 to 24%) by flooding with mineral oil, followed by recombined crude oil. The core was aged for at least one week, then waterflooded to S_{orw} (29 to 34%) with 4.5 PV brine at 1.8 m/d. The gas flood (3 PV at 0.45 m/d) that followed was run either with methane to immiscible gas S_{org} (19%) or with Snorre gas to miscible gas S_{org} (13%). After gas flooding, the core was flooded with 2 PV of 0.5% surfactant solution over 24 hours, aged for 24 hours, and flushed with another 2 PV surfactant solution over 24 hours to satisfy the adsorption requirements of the rock. For foam experiments in oil-free core, a gas flood with methane (1.6 PV at 0.5 m/d) and the surfactant pre-flush followed brine saturation directly.

A series of foam floods was run at each oil saturation by co-injecting surfactant solution (at different concentrations) with one of three gases at a total interstitial velocity of 1.2 m/d and a gas fractional flow or foam quality of 80% (at core inlet conditions). After some foam floods, gas only was injected at 1.2 m/d to determine residual gas mobility reduction. When injected fluids (gas, or surfactant type and concentration) were changed, the core was usually pre-flushed with these fluids before running a foam experiment. All experiments were run at 90°C and 300 bar.

3. RESULTS AND DISCUSSION

Foam performance was evaluated from measured pressure drops across the core by calculating apparent gas viscosities (η_{app}) in the presence of foam using the single phase Darcy law:

$$\eta_{app} = \frac{k_{abs} A}{q_g} \frac{\Delta P}{L}$$

where k_{abs} is absolute permeability to brine, A is core cross-sectional area, q_g is volumetric gas flow rate, ΔP is pressure drop, and L is core length. Because of the loosely consolidated nature of the core, the absolute permeability varied somewhat each time the core was cleaned with solvent and re-saturated with brine. Absolute permeabilities were 72 mD, 140 mD, and 110 mD for experiments at immiscible, miscible, and zero oil saturation, respectively. For comparison with foam apparent viscosities discussed below, "baseline" apparent gas viscosities in the absence of surfactant, measured at the end of the gas floods preceding foam injection, were 0.5 cP with methane at $S_o=19\%$ and $S_o=0$, and 0.7 cP with Snorre gas at $S_o=13\%$.

3.1. Foam Propagation

A continuous record of the pressure trace measured during foam flooding at immiscible gas flood S_{org} (19%) is shown in Figure 1. The numbers in square brackets are experiment numbers and have been added for ease of discussion. The x-axis can be converted to throughput using the injection rate of 2 PV per day during foam flooding and gas flooding after foam.

Although pressure drops generated by a variety of fluid systems are compared in Figure 1, a slowly increasing trend in pressure drops over time, independent of the fluid system injected, is evident. The delay in response to foam injection of the two-thirds and one-third core sectional pressure transducers points to slow foam propagation. The two-thirds core pressure trace starts to increase 11 days after the start of foam injection; the one-third core pressure transducer shows no response until 27 days into the foam flooding sequence, but does not reach its theoretical value of 1/3 of the full core pressure drop even after 32 days. The delay in foam propagation is not related to surfactant adsorption. During the surfactant pre-flush, approximately 4.5 times the amount of surfactant required to satisfy adsorption was injected (9). Chemical analysis of an effluent sample taken near the end of Experiment [1] showed that the produced surfactant concentration was equal to the injected concentration.

At miscible gas flood residual oil saturation (13%, Figure 2), significant pressure drops are developed within one day of foam injection. At least some foam propagates through the core during the first foam flood (Experiment [1] in Figure 2) as evidenced by the response of the one-third core pressure transducer. The one-third core pressure drop does, however, increase in proportion to the full core pressure drop up to Experiment [11], and stays approximately constant relative to the full core pressure drop afterwards.

In the oil-free core, foam is generated and propagated within the first day of foam injection (Figure 3). The relative proportion of the sectional pressure drops to the full core pressure drop remains approximately equal in all foam floods.

Based on these observations, the level of oil saturation evidently affects the ease of foam propagation significantly. Because the differences in foam propagation were not anticipated, shut-in periods between the

end of the surfactant pre-flush, preceding Experiment [1], and the first foam flood were 1 day, 16 days, and 0 days for the experiments in Figures 1, 2, and 3, respectively, in addition to the three days required for the surfactant pre-flush itself. If a noticeable response in one-third core pressure drop is taken to indicate foam propagation through most of the core, then propagation times can be estimated as follows:

	$S_o=0$	$S_o=13\%$	$S_o=19\%$
Days after first surfactant contact	<4	21	31
Days after start of foam flooding	<1	2	27
PV foam injected	1	2	38

The times represent elapsed time, including surfactant, foam, and gas floods, as well as shut-in periods, while the last row of data represents foam floods only. Regardless of which data set is used to assess foam propagation, it can be concluded that foam propagates more slowly at higher oil saturation in the rock/fluid system of this study. No oil or emulsion was produced during foam flooding. The gradual increase in pressure drop therefore cannot be attributed to a slowly decreasing oil saturation.

3.2. Ageing Effects on Foam Performance

Figures 1 to 3 not only show that foam propagates slowly under some conditions, but also that a period of "ageing" is required before the foam reaches the maximum attainable apparent viscosity. Although it is not possible to determine from the available data if ageing depends on continuous foam injection or simply on contact time of the core with surfactant under flow or no-flow conditions, and although the sequence of experiments run within each of the three sets of experiments differed somewhat, some conclusions regarding core ageing may still be drawn.

The core is considered "fully aged" when pressure drops during foam injection with the same fluid system no longer change over time. Consider, for example, the experiments of Figure 2. Pressure drops during injection of 1% C_{14-16} AOS/Snorre gas are essentially the same in Experiments [8] and [12]. The core is therefore considered fully aged at Experiment [8], i.e. 16 days after the start of foam injection, or 35 days after first contact of the core with surfactant. Similarly, Figure 3 indicates that ageing is complete at Experiment [9]. During the experiments of Figure 1, insufficient repeat experiments were performed to allow the same kind of analysis. Judging by the one-third core pressure drop, a fully aged condition is probably not reached during the experiments of Figure 1. An estimate of ageing time is, however, still possible. Times at which a fully aged condition is reached are then estimated as follows:

	$S_o=0$	$S_o=13\%$	$S_o=19\%$
Experiment number	[9]	[8]	>[15]
Days after first surfactant contact	24	35	>28
Days after start of foam flooding	21	16	>24
PV foam injected	14	16	34

Significant ageing times appear to be required at all three oil saturations. More important, however, are the differences in the dependence of foam strength on ageing time. Large pressure drops are developed in the first foam flood at $S_o=0$ and $S_o=13\%$, corresponding to apparent foam viscosities of 264 and 192 cP, respectively. Although even higher apparent viscosities are attained after ageing, a fully aged condition is not necessary for effective foam formation at these two oil saturations. By contrast, an apparent foam viscosity of only 7 cP was generated during the first foam flood at $S_o=19\%$, but foam strength increased greatly during continued foam injection.

The relative importance of ageing on foam strength can be quantified by taking the ratio of the full core pressure drop under fully aged conditions to the pressure drop for unaged conditions during foam injection with identical fluid systems:

	$S_o=0$	$S_o=13\%$	$S_o=19\%$
ΔP ratio (aged/unaged)	1.5	2.7	> 4.6
Experiment #	[13]/[1]	[18]/[1]	[8]/[3]
Fluids	0.5% C ₁₄₋₁₆ AOS, methane	0.5% C ₁₄₋₁₆ AOS, methane	2% C ₁₄₋₁₆ AOS, methane

A 4.6-fold increase in pressure drops is observed at $S_o=19\%$ when going from unaged to aged conditions. This ΔP ratio is conservative, because the core was not yet fully aged during Experiment [8]. (Experiments with the same fluid system were not available for unaged and fully aged conditions within this particular set.) More realistically, the ratio is in the range of 20 to 30. This compares to a relatively small increase in pressure drop of 50% at zero oil saturation. Ageing is thus essential for the development of strong foam at 19% oil saturation, but not at 13% or zero oil saturations.

The gradual increase in pressure drops, particularly in Figure 1, was not caused by core plugging due to solids, for the following reasons: 1. Surfactants and brine were completely soluble at the experimental conditions. 2. Foam pressure drops after ageing approached values typically measured for the same rock/fluid system elsewhere (8). 3. Periodic gas injection after foam resulted in consistently low pressure drops that did not show an increasing trend over time throughout each injection sequence. 4. A progressive decrease in the core's permeability after re-cleaning the core following each set of experiments was not observed.

In the oil-free, surfactant saturated core, foam propagates at a rate close to the injection rate, consistent with Chou's (2) experiments. Chou has argued that foam propagation requires the formation of at least some lamellae that are stable enough to increase the local capillary pressure sufficiently to exceed the capillary entry pressure for the smaller pores. If stable lamellae are present, gas is forced into smaller pores, where additional lamellae are formed by snap-off, provided surfactant solution is present. The rate of foam propagation then depends on how fast the capillary pressure can be raised to induce lamella formation in increasingly smaller pores.

The gradual increase in pressure drop in the oil-free core, denoted ageing in the discussion above, may be caused by slow lamella generation in smaller and smaller pores, until the fully aged condition is reached when lamellae have been formed in the smallest accessible pores. A wide pore size distribution, observed in Snorre rock, is expected to compound the ageing effect. In the presence of residual oil, the lamellae initially formed may not be stable enough to force gas to enter smaller pores, resulting in a more pronounced ageing effect and slow foam propagation. This kind of reasoning to explain the observed ageing effect would imply that ageing depends on continued foam injection rather than just prolonged contact of the core with surfactant.

Stable lamellae (high apparent foam viscosities) are, however, eventually generated in the presence of oil, despite the fact that the oil saturation does not change during foam flooding. A possible reason could be wettability effects. While foam cannot be stable in oil-wet porous media, it has been shown that surfactants tend to change wettability to water-wet (12,13). Snorre rock is believed to be mixed wet. In the oil-free rock, the surfactant will rapidly change the rock towards water-wet, which is the condition favorable to foam formation. When oil is present, the solid surfaces wetted by oil will be less accessible to the surfactant, particularly at high oil saturation. A slower change towards more water-wet conditions may then contribute towards the ageing effect.

Injection of a surfactant slug appears to promote foam formation at $S_o=19\%$. An immediate increase in pressure drops is evident after each surfactant pre-flush ([4], [7], and [20], Figure 1). A similarly strong effect is not observed at the lower oil saturations ([6] and [10], Figure 2, and [5], Figure 3). Consistent with the observations of others (1-4), injection strategy appears to affect foam generation.

3.3. Effect of Gas Composition

Apparent foam viscosities measured with three gases under fully aged conditions are shown in Figure 4. At miscible and immiscible gas flood residual oil saturation, the type of gas has very little effect on foam performance at the conditions of these core floods. At zero oil saturation, Snorre gas foam generates higher apparent viscosities than methane foam. More general conclusions as to the effect of gas composition on foam performance cannot be reached on the basis of this limited data set. Other studies have shown that the combined effects of gas composition and pressure can strongly affect foam performance under some conditions (12).

3.4. Effect of Oil Saturation

After completion of the experiments in Figure 2, two gas/oil co-injection experiments were run to simulate the field condition of gas/oil flow into a foam-filled zone. These are described in Reference 9. For the purpose of this paper, it suffices to say that this increased the average oil saturation in the core. Resuming foam flow after gas/oil injection thus allowed the measurement of apparent foam viscosities at 15% and 18% oil saturations. Oil was then injected into the core, followed by a waterflood, then a foam flood. The average oil saturation when steady state was reached during the foam flood was approximately 42%.

Apparent viscosities measured with Snorre gas, methane, or nitrogen foam at different oil saturations under fully aged conditions are shown in Figure 5. A steep decrease in apparent viscosity is evident at a "critical" oil saturation between 13% and 15%. At oil saturations less than or equal to miscible gas flood residual (13%), foam performance is no longer affected significantly by oil.

3.5. Residual Gas Mobility Reduction

When gas alone was injected into the core immediately following gas/surfactant co-injection, pressure drops always decreased steeply over several hours and then stabilized over longer injection periods of 10 to 15 hours (Figures 1 to 3). Apparent viscosities measured during foam injection and during gas injection following foam, calculated from steady state pressure drops, are listed in Table 2, for fully aged conditions.

Compared to the "baseline" apparent gas viscosity before contact of the core with surfactant (0.5 to 0.7 cP), significant residual gas mobility reduction is observed. When expressed as a percentage of the apparent foam viscosity during the foam flood immediately preceding gas injection, residual apparent gas viscosities measured with three gases at three oil saturations are similar, within the accuracy of the measurements. A slight increase in residual gas mobility reduction was observed when going from the unaged to the aged condition; sufficient data to reach rigorous conclusions were, however, not collected.

Table 2. Residual gas mobility reduction during gas injection after foam flooding, fully aged core.

S_o (%)	Gas	$C_{14-16}AOS$ conc. (%)	η_{app} (foam) (cP)	η_{app} (gas) (cP)	$\frac{\eta_{app}(gas)}{\eta_{app}(foam)}$ (%)
0	Methane	0.5	292	15	5.1
0	Snorre gas	0.5	582	32	5.5
13	Methane	0.5	514	39	7.6
13	Snorre gas	1.0	1002	46	4.6
13	Snorre gas	1.0	1034	48	4.6
13	Nitrogen	0.5	527	48	9.1
19	Snorre gas	2.0	205	11	5.4
19	Nitrogen	2.0	211	13	6.2

4. CONCLUSIONS

1. Apparent foam viscosity depends on oil saturation, with a steep decrease in apparent viscosity at a "critical" oil saturation of 13 to 15%.
2. Miscible gas flood residual oil saturation is low enough that it does not interfere with foam generation. Very strong foam, with apparent foam viscosities up to 1000 cP, can be generated, compared to apparent gas viscosities in the absence of surfactant of 0.5 to 0.7 cP. Above the critical oil saturation, strong foams (apparent viscosity 200 cP) can still be formed.
3. The rate of foam propagation during surfactant/gas co-injection, and the rate at which the maximum attainable foam strength develops, denoted "ageing," decrease with increasing oil saturation.
4. Foam performance with three different gases (Snorre field gas, methane, nitrogen) is very similar under the conditions of these experiments.
5. Significant residual gas mobility reduction was observed during gas injection into the foam-filled core.

5. ACKNOWLEDGEMENTS

The authors gratefully acknowledge Saga Petroleum and the license partners of the Snorre field for permission to publish this work, and Vladimir Masata, Jon Goldman, and Monty Hans of PRI for conducting the laboratory work.

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Figure 1. Pressure trace recorded during foam flooding and gas flooding at $S_o = 19\%$. Velocity 1.2 m/d (2 PV/d) unless otherwise noted.

Figure 2. Pressure trace recorded during foam flooding and gas flooding at $S_o=13\%$.
Velocity 1.2 m/d (2 PV/d) unless otherwise noted.

Figure 3. Pressure trace recorded during foam flooding and gas flooding at $S_o=0$. Velocity 1.2 m/d (2 PV/d) unless otherwise noted.

Figure 4. Effect of gas type on foam performance, C14-16 AOS in "aged" core.

Figure 5. Dependence of apparent foam viscosity on oil saturation, C14-16 AOS with different gases in "aged" core.