




Foam Generation, Propagation and Stability in Porous Medium

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Abstract

There have been several foam field applications in recent years. Foam treatments targeting gas mobility control in injectors as well as gas blocking in production wells have been performed without causing operational problems. The most widely used injection strategy of foam has been injecting alternating slugs of surfactant in brine with gas injection. This procedure seems to be beneficial as injection is easy to perform and control below fracturing pressure. Simultaneous injection of surfactant solution and gas may give difficulties, especially with interpretation of the tests, if fracturing pressure are exceeded during the injection period. This paper reviews critical aspects of foam for reservoir applications and intends to motivate for further field trials. Key parameters for qualification of foam are: foam generation, propagation in porous medium, foam strength and stability of foam. Stability is discussed, especially in the presence of oil at reservoir conditions. Data on each of these topics are included, as well as extracted summary of relevant literature. Experimental studies have shown that foam is generated at low surfactant concentration even below the CMC (critical micelle concentration). Results indicate that in situ foam generation in porous medium may depend on available nucleation sites. In situ generation of foam is complex and has been found to be especially difficult in oil wet carbonate rocks. Foam propagation in porous medium has been summarized, and propagation rate for a given experiment seems to be constant with time and distance. Laboratory studies confirm a propagation rate of 1–3 m/day. Field tests performed have not given reliable information of foam propagation rate, and future field pilots are encouraged to include observation wells in order to gain information of field-scale foam propagation. Foam strength is generally high with all gases. The exception is CO₂ at high pressure where CO₂ becomes supercritical. Stability of foam has been studied in laboratory and field tests, and has confirmed long-term stability of foam.

Keywords Foam · Foam generation · Foam propagation · Stability of foam

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1 Introduction

Oil recovery by gas injections is the most widely used recovery method for light, condensate and volatile oil reservoir. Typical gases that are used include CO₂, hydrocarbon gases (e.g., CH₄), N₂, air and steam. The “choice” of gas composition in a field situation depends on several factors such as gas availability, recovery conditions (miscible/immiscible) and many technical and economical evaluations of which fluids are appropriate for the field.

Gas injections for improving oil recovery often lead to early gas breakthrough, and poor volumetric sweep efficiency of the reservoir, and later stage severe problem with gas handling and/or recycling of gas. Displacement instabilities and poor sweep during gas injections can be traced to the low viscosity and density of injected gas, but also coupled to reservoir heterogeneity.

Foam has been applied for gas shutoff in production wells, and as a mobility control agent especially in gas injection of WAG (water alternating gas) operations where early gas breakthrough may occur. Recent field experiences (Blaker et al. 2002; Skoreyko et al. 2011; Ocampo-Florez et al. 2014; Ocampo et al. 2018) have proved that foam improves sweep efficiency and can divert injected gas. In addition, foam may increase the oil plateau period for mature oil fields by reducing the gas/oil ratio for wells suffering from high gas production. The foam processes, both production- and injection well treatments, are considered rather low-cost processes.

Foam is defined as a dispersion of gas in liquid (Hirasaki 1989; Kovscek and Radke 1994) and has been utilized as a tool for gas mobility- and conformance control in porous media for a wide range of applications, since the late 1950s. Industrial applications of foam in porous formations include enhanced oil recovery (EOR) (Aarra and Skauge 2000; Enick and Olsen 2012; Rossen 1996; Zhdanov et al. 1996), matrix-acidizing treatments (Thompson and Gdanski 1993; Parlar et al. 1995; Zeilinger et al. 1995), improved underground storage of gas (Smith and Jikich 1993), as well as contaminated-aquifer remediation (Hirasaki et al. 1997). Despite its unique properties, broad applicability and extensive experience gained over the past 60 years, foam has not become a standard reservoir engineering oil recovery process. One reason may be the lack of predictive foam flow models in porous medium.

A successful well treatment with foam is critically depended on the correct placement of foam with specific properties to stimulate the current reservoir problems. Specific foam properties can include strong and stagnant foams (i.e., very low mobility foams) for production well treatments to reduce unwanted high gas/oil ratio (GOR). While relatively, weaker and more mobile foams can be more optimal to support the gas injection front with mobility control deeper into the porous formation without impairing injectivity. Accordingly, a sound understanding of the problem to be solved, reservoir properties and foam properties in porous media becomes important.

This paper focuses on foam generation, propagation and stability in porous media in relation to EOR processes. The efficiency of foam to reduce gas mobility (i.e., foam generation), the injection time required for foam to reach a given depth in the reservoir (i.e., foam propagation) and foam lifetime and persistence to various conditions during as well as after its placement (i.e., foam stability) are key questions for all intended field applications with foam in relation to EOR.

Gas injections for EOR often lead to early gas breakthrough, meaning poor volumetric sweep efficiency of the reservoir and later severe handling and/or recycling of gas. Application of foam can be a technically feasible way to overcome the shortcomings of gas injections. In fact, if correctly designed, foam can be formed within the reservoir when gas and surfactant

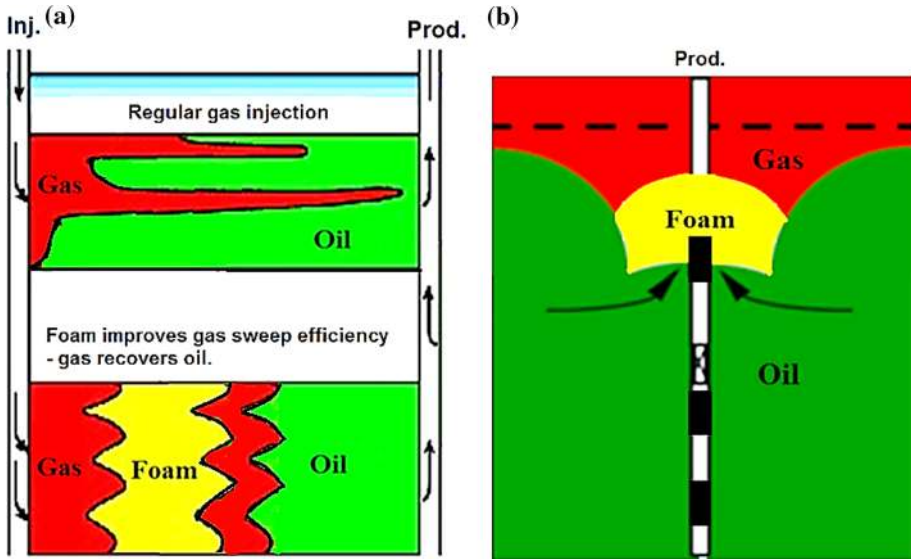


Fig. 1 Field applications of foam for EOR: **a** injection well treatments; support gas injections with improved mobility control, **b** production well treatments; prevent unwanted fluids from coning, cusping or channeling into the wells (i.e., GOR/WOR control)

solution flow together, which can potentially overcome all the three sources of poor sweep efficiency recently addressed by gas injections.

Foam can reduce gas mobility and divert gas to unswept areas of the reservoir, thus, supporting gas injections to improve its sweep efficiency and to recover more oil. In addition, foam has demonstrated effective as a tool to block unwanted gas production in production wells (Fig. 1). The foam processes, both production- and injection well treatments, are considered rather low-cost processes.

An illustration of foam applications for EOR is given in Fig. 1. The reservoir problems to be handled by foam treatment should be relevant to oil fields/reservoirs suffering from early gas breakthroughs, poor sweep efficiency of injected fluids, unwanted high gas production and/or undesirable high levels of gas recycling.

Foams can be generated at very low surfactant concentrations, including below the critical micelle concentration (CMC), Fig. 2. The foam generation at low surfactant concentration has been extensively documented (Sanchez and Schechter 1989; Alkan et al. 1991; Kuhlman et al. 1992; Dixit et al. 1994; Heller 1994; Tsau and Grigg 1997; Apaydin and Kovsky 2001; Mannhardt and Svorstøl 2001; Vikingstad et al. 2006; Fekarcha and Tazerouti 2012; Simjoo et al. 2013; Rohani et al. 2014). Especially properties of alpha olefin sulfonates (AOS) have been studied, as in Fig. 2, where we compare data for, foam height, aqueous solution viscosity and speed of sound, as a function of surfactant concentration. The CMC is detected by an abrupt change in aqueous solution speed of sound at surfactant concentration of 0.0022 wt%. Higher surfactant concentration shows increasing foam height even if the solution properties of surfactant changes from spherical micelles to larger structures like ellipsoids or laminal structures.

In order to understand the influence of oil saturation on foam, more fundamental experimental studies have been performed. The static foam properties have been investigated by

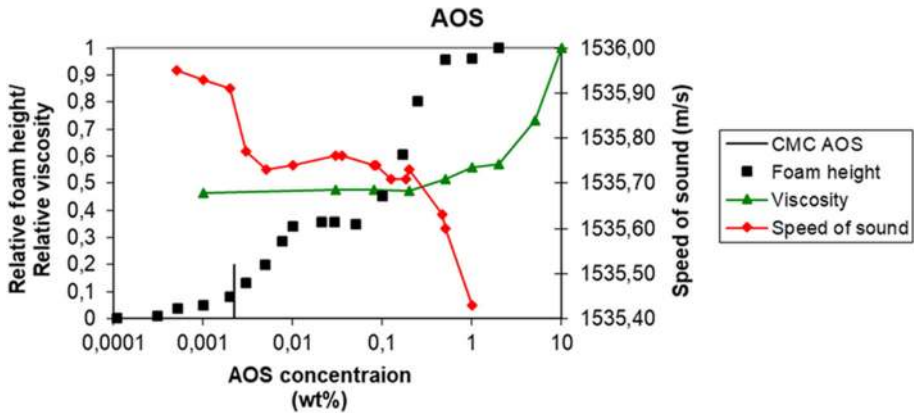


Fig. 2 Static foam height versus surfactant concentration compared to changes in aqueous solution properties (viscosity at a shear rate of 10 s^{-1} and speed of sound at ambient conditions)

variation in surfactant concentration, amount of added oil and variation in polarity of the oil phase.

The foam generation and foam stability in static foam tests is found to be related to the structure of the surfactant aggregate in the water phase. The foam quality in the presence of alkane-type oils is related to the ability of the surfactant to solubilize the oil molecules (Vikingstad et al. 2006). The viscosity ratio between oil and water is also important for foam stability.

For crude oil, systematic multi-variant analysis has been used to identify the most important factors influencing foam stability (Vikingstad et al. 2005). The variables investigated were acid number, base number, oil viscosity, content of saturates and asphaltenes, interfacial tensions and spreading coefficients.

2 Materials and Methods

Foam tests involved static mixing of air into a surfactant solution. The procedure has been described elsewhere (Vikingstad et al. 2005). Air was dispersed into the 300-ml test solution at a speed of 2000 rpm (rounds per minute) for 5 min using a static mixer. Solutions were mixed in 1000-ml glass cylinders measuring 44 cm high and 6 cm in diameter. During mixing, there were unlimited air supply and no restrictions on foam expansion. After mixing, the glass cylinder was closed with a plastic seal. Foam height was always well below the top. The experiments were performed at ambient conditions. All of these experiments were performed in synthetic seawater.

In addition to the static foam tests, viscosity and speed of sound measurements were performed for AOS bulk solutions. A large surfactant concentration interval was investigated. The viscosity of the solutions was measured using a Physica MCR 300 Rheometer. All the experiments were performed at room temperature. The shear rate was 10 1/s in the measurements. The speed of sound of the bulk surfactant solutions was measured at $(25.000 \pm 0.003) \text{ }^\circ\text{C}$ by the Rubidium clock sound velocimeter described elsewhere (Høgseth et al. 2000). The speed of sound cells was calibrated with water using the data of Del Grosso and Mader (1972). The estimated error in the measurements was 0.02 m/s .

3 Foam Generation

Foam generation and foam coalescence in porous media have been divided into three generation processes: snap-off, leave behind and lamella division and two destabilizing processes: capillary-suction coalescence and diffusion coalescence (Kovscek and Radke 1994; Rossen 1996). Recently, two new generation mechanisms involving interactions between neighboring bubbles have been discovered: “neighbor–neighbor pinch-off” and “neighbor-wall pinch-off” (Liontas et al. 2013).

Foamability and foam stability are important topics in evaluating surfactants for possible use in field applications of foam. The ability of surfactants to generate foam at low concentrations can be very important if performing a water alternating gas process after a foam operation where the ability to generate high mobility foams can improve sweep efficiency and possibly increase the extension of the three-phase region.

3.1 Minimum Surfactant Concentration

Investigation of foamability and stability at a range of different surfactant concentration for the two surfactants, FS-500, a perfluoroalkyl sulfobetaine and an alpha olefin sulfonate (AOS) surfactant has been examined in our previous publications (Vikingstad et al. 2005, 2006). The critical micelle concentration (CMC) was measured to 0.0028 wt% for the FS-500 surfactant, whereas CMC for the AOS surfactant was measured to 0.0022 wt%. The foam generation ability was connected with surfactant concentration and was most profound for the AOS surfactant, but the experiments showed that both surfactants generated foam even below CMC.

There is a lack of correlation between static foam and foam generated in porous medium. Adsorption of surfactant will delay the in situ porous medium formation of foam, but after adsorption equilibrium is achieved, low concentration of surfactant can generate strong foam.

Performing core flooding experiments with the AOS surfactant at reservoir conditions, respectively, 114 °C and 350 barg, using reservoir core material and in the presence of a residual oil saturation showed that strong foams were generated both at 0.1 wt% and 0.5 wt% AOS concentrations (Aarra and Skauge 2002).

3.2 Foam Quality in Porous Medium

Foam quality is defined as the fraction of gas volume divided by the fraction of gas and surfactant solution volume injected. Several reported core flooding studies report generation of constant water saturations along the cores.

In core flooding studies by Ettinger and Radke (1992), foam texture is considered governed by the porous media itself through strong making and breaking processes. Core flooding studies revealed a constant water saturation of approximately 0.3–0.35 fraction of pore volume for both in situ and pre-generated foam when the fraction of gas varied between 0.7 and 0.9 at constant water rate. Persoff et al. (1991) report similar water saturation from experiments in 1 D Boise sandstone. Also in our experiments in a North Sea reservoir core at 30 barg and room temperature, a constant water saturation of approximately 0.35 was measured at foam qualities of 50, 65 and 90% (Fig. 3). Experiments by De Vries and Wit (1990) and Osterloh and Jante (1992) agree with measurements of constant liquid saturation, respectively, 18 and 6%, but find that the pressure gradient not proportional to the increase in liquid velocity at steady state and suggested power law dependence. High foam qualities were used in

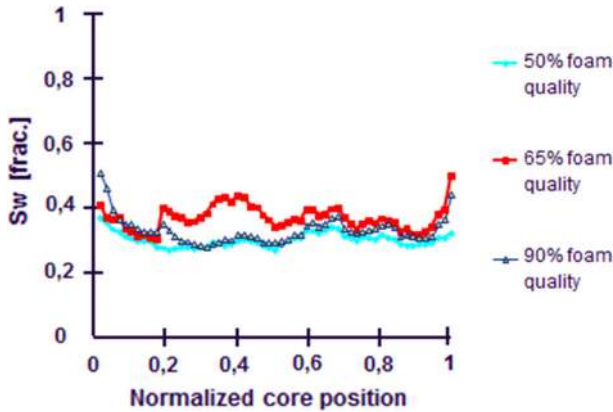


Fig. 3 Water saturation along the reservoir core (0 = inlet, AOS, 30 bar, room temperature, $S_o = 0$)

both these studies. Flow at the limiting capillary pressure (Zhou and Rossen 1992) has been introduced.

In EOR applications, foam has been used primarily for conformance and/or mobility control during gas injections or to shut off unwanted gas inflow in production well treatments. Foam properties for conformance control and sweep improvements need the ability to flow large distances, whereas foams for gas shut off applications need to be strong and have high stability.

How to generate, propagate and place foam in optimum position in reservoirs is very important parts of any field application of foam together with a good description of the reservoir problem to treat. The foam could either be generated prior to injection, or in situ in the reservoir. Combination of these two techniques is another alternative. Usually four different foam generation methods might be applied. The first one includes injection of pre-generated foam in which knowledge of foam quality will be very good. A second method involves co-injection of surfactant solution and gas at certain fractional flows. A third option involves the surfactant alternating gas method (SAG) in which slugs of surfactant solution and gas are injected into the reservoirs. The length and volumes under such operations can be design related to the foam quality. The fourth method involves injection of a large slug of surfactant followed by gas. For foams for conformance control and sweep efficiency the injected gas will generate foam in high permeable areas already flooded and swept to a lower oil saturation, and by reducing the gas mobility the injected gas is diverted to new areas and increase the oil recovery. Foams for gas shut off purposes need to be strong and stable to reduce gas from coning, cusping or channeling into the production well.

3.3 Foam Generation Methods for Field Application

Examination of several foam field pilots shows that all foam generation techniques have been applied in different pilots. The most used technique is the SAG (surfactant alternating gas) method either alone or combined with co-injection of surfactant solution and gas or with injection of pre-generated foam. Evaluation of the interpretations and results from these foam trials have shown that both positive and negative results have been achieved (Heuer and Jacobs 1968; Krause et al. 1992; Aarra et al. 1996; Aarra and Skauge 2000, 2002; Zhdanov et al. 1996; Thach et al. 1996; Svorstøl et al. 1997; Chukwueke et al. 1998; Blaker et al. 2002;

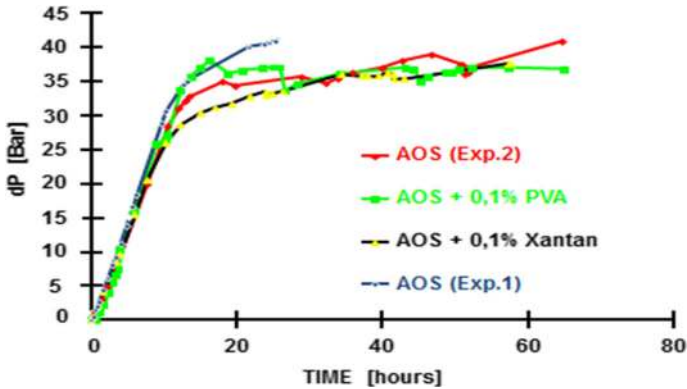


Fig. 4 Foam generation with and without added polymer in Berea sandstone core material at 40 °C and 110 bar, $S_o = 0$

Skauge et al. 2002; Enick and Olsen 2012; Ocampo et al. 2013; Rossen et al. 2017). The surfactant concentration issue discussed earlier, open for testing is foam can be re-freshened with further WAG cycles after SAG. This will counteract the foam drying effect and gravity segregation that may act over time in the reservoir.

3.4 Foam Quality in Porous Medium

In some of the field tests, a polymer was added to the water phase together with surfactant. Our experience with polymer-based foams showed that addition of 1000 ppm polymer (PVA or Xanthan) to the AOS surfactant solution in Berea sandstone core material did not seem to change foam formation (Aarra et al. 1997). The results are shown in Fig. 4 and shows that foams of similar strength were generated both with and without polymer added.

3.5 Minimum Pressure Gradient for Generating Foam

In the literature, there has been discussed if there is a minimum pressure gradient, which is needed to generate foam. Late studies of Yu et al. (2018) find that there is a critical velocity for foam generation from experiments in Bentheimer sandstone, while Almajid and Kovscek (2016) present foam experiments in silicon micromodels where foam was generated by co-injecting N_2 gas and AOS surfactant and observed no critical velocity for foam generation. Foam generation by hindered snap-off and foam coalescence by pinch-off was observed.

3.6 Minimum Permeability for Generating Foam

A challenge for foam field application will be application of foam in low permeable heterogeneous reservoirs. Foam generation in low permeable laminated core material has shown generation of foam in low permeable Berea sandstone cores (Solbakken et al. 2014) similar to findings from Siddiqui et al. (SPE 37416 1997). Permeability contrasts within low permeable reservoir can be as severe as in high permeable reservoirs, and specific reservoir characteristics need to be evaluated to find foam properties to improve sweep efficiency and to increase oil recovery. AOS foams have been generated at high residual oil saturations (35–41%) with

MRF's ranging from 12 to 67 using three different North Sea oils (Vikingstad and Aarra 2009).

3.7 Need for Nucleation Sites

Wettability may influence the in situ foam generation. In sandstones, the heterogeneous mineralogy gives sites with different surface charge and strength of electrostatic properties. In such material, we have never seen any problem of generating foam in situ. Carbonates have in general more homogeneous surface charge and may be more oil wet. The rock surface can be covered with continuous oil films, which is confirmed with no spontaneous water imbibition, while oil is spontaneously imbibed. Foam in some carbonate rock has shown difficulty for in situ foam generation (Aarra et al. 2011). In this study, in situ foam could not be generated, but pre-generated foam was transported through the porous medium.

4 Foam Propagation

The efficiency of foam to reduce gas mobility (i.e., foam strength) and its stability are key questions for all intended field applications. Various parameters have been used to determine the efficiency of foam in porous media (Heller 1994), and one common parameter is the mobility reduction factor (MRF):

$$\text{Mobility Reduction Factor (MRF)} = \frac{\Delta P_{\text{foam}}}{\Delta P_{\text{no-foam}}} \quad (1)$$

where ΔP_{foam} and $\Delta P_{\text{no-foam}}$ are the measured differential pressure across the porous medium with and without foam, respectively, at the same gas/water ratio. A high MRF corresponds to strong foam.

The foam performance offered by a given surfactant may depend on several factors, such as surfactant type and concentration, type of gas and gas composition, rock properties, oil saturation, foam–oil interactions, brine salinity, temperature and pressure conditions, flow rates, injection strategies and so on.

The typically used gases types in foams include CO₂, N₂, air, hydrocarbon gases (e.g., CH₄) and steam. The “choice” of gas composition in a field situation typically depends on gas availability, the recovery conditions and an economic assessment of the appropriate fluid for the field (Aarra and Skauge 2002; Enick and Olsen 2012; Holm and Garrison 1988; Manrique et al. 2010; Turta and Singhal 1998; Zhdanov et al. 1996).

Several laboratory studies have compared the CO₂-foams with the N₂-foams in outcrop sandstone core material, without oil, using commercial anionic surfactants, under different experimental conditions. Typically the generated CO₂-foams have been significantly weaker (i.e., lower pressure gradients along the porous media) than the N₂-foams generated under similar experimental conditions (Chou 1991; Seright 1996; Kibodeaux 1997; Gauglitz et al. 2002; Du et al. 2008; Farajzadeh et al. 2009; Aarra et al. 2014; Zeng et al. 2016). Certain N₂-foams in the literature have been extraordinarily strong, reflected by very large pressure gradients along the porous media, which are often $\gg 50$ bar/m (Chou 1991; de Vries and Wit 1990; Friedmann et al. 1991; Kovscek and Radke 1994; Vikingstad and Aarra 2009; Solbakken et al. 2014; Siddiqui et al. 1997; Zeilinger et al. 1995). Laboratory experiments using methane gas have also reported the formation of strong CH₄-foams. The generated methane foams have repeatedly demonstrated their robustness under high-pressure and high-

temperature field conditions (Aarra et al. 1997, 2011; Aarra and Skauge 2002; Holt et al. 1996; Mannhardt et al. 2000; Mannhardt and Svorstøl 2001; Svorstøl et al. 1997).

4.1 CO₂-Foams

A summary of many studies on CO₂-foam in *sandstone* and in carbonate rock material in the absence of oil reveals that few surfactants can generate a CO₂-foam of similar strength and stability under elevated experimental conditions as those reported with the N₂- and CH₄-foams. However, all of the studies on CO₂-foam referenced below show that the CO₂ mobility can be lowered with a variety of surfactants, although significant differences in the degree of mobility control have been reported (Alkan et al. 1991; Bian et al. 2012; Chabert et al. 2012, 2014; Chen et al. 2012; Elhag et al. 2014; Heller 1984, 1994; Khalil and Asghari 2006; Kuehne et al. 1992; McLendon et al. 2012; Prieditis and Paulett 1992; Sanders et al. 2010; Tsau and Heller 1992; Tsau and Grigg 1997; Yang and Reed 1989; Xing et al. 2010; Zeng et al. 2016).

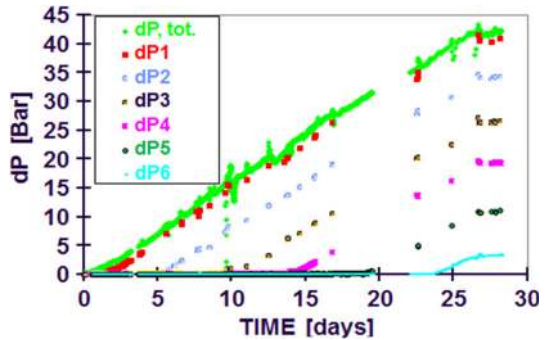
In experiments reported by Chou (1991), foam propagation without oil depends on the initial condition of the core material. Pre-saturating the core with surfactant solution prior to foam generation seemed beneficial for both foam generation and foam propagation. This is also usually recommended task for any foam field application. In Chou's experiments, foam propagation, without oil, was close to the injection rate similar to other reported core flooding experiments (Mannhardt and Svorstøl 1999; Vikingstad and Aarra 2009; Solbakken 2015) using different types of gas.

Vikingstad and Aarra (2009) report foam propagation results in outcrop Berea sandstones at 50 °C and 120 bar. Two surfactants were tested: a zwitterionic perfluoroalkyl betaine and an anionic C_{14–16} alpha olefin sulfonate (AOS) surfactant. Two pore volumes of surfactant solution were flooded through the cores prior to foam generation. The foam propagation rate, without oil present in the core, was according to the injection rate (3.6 m/day) and generated very strong foams.

The influence of residual oil in the cores showed very different behavior for the two surfactants. The FS-500 surfactant showed significantly delayed propagation rate at residual oil, while the AOS showed faster propagation at Sor and reduced foam strength.

Foam propagation was also studied in a 91-cm reservoir core model (Aarra et al. 1997). Foam was generated by co-injecting methane gas and 1 wt% AOS surfactant solution into the core at 40 ml/h at a foam quality of 65%. Two pore volumes of surfactant solution were injected prior to foam generation. The residual oil saturation in the core was 0.1 PV. Foam propagation through the core was monitored by 6 pressure ports along the core (Fig. 5). A very stable foam front was propagating at constant front rate through the core. The interstitial velocity in this experiment was 3.9 m/D, and the low mobility zone moved by approximately 0.035 m/D. The wettability of the reservoir core material is intermediate- to water-wet based on measurement of the Amott index of 0.48 on similar reservoir core material. The wettability may, in addition to the residual oil saturation, reduce foam propagation rate as foam nucleation sites may be unavailable for foam generation. Mannhardt and Svorstøl (1997) studied foam generation and foam propagation at Snorre reservoir conditions and reported a strong dependence of foam propagation on oil saturation. Higher oil saturation reduced foam propagation and foam propagation in the absence of oil followed the injection rate. Vassenden et al. (1998) reports that the foam front propagates approximately as fast as the injected fluids in a 10-m sandpack without oil. The frontal displacement is in agreement with gas–water frontal movement under steady-state conditions. However, with only an oil saturation of 5

Fig. 5 Foam propagation using 1 wt% AOS in reservoir core, foam quality 65%, $Q = 40$ ml/h, at 290 bar and 100 °C



per cent the foam frontal rate was significantly lowered. The strong foam propagation front had a velocity of 0,035 m/D in the sand pack core model at residual oil saturation of 0,05 PV. The delayed foam propagation in the presence of oil can be explained if the foam can mobilize oil by an extraction mechanism. Slow foam propagation was successfully simulated the frontal movement by allowing oil to evaporate into the gas or to solubilize oil in the surfactant solution. The appearance of a high-pressure gradient in a section was interpreted as strong low mobility foam.

4.2 Influence of Heterogeneity on Foam Propagation

Effect of lamina and core heterogeneities have been studied in foam experiments in three low permeable Berea sandstone cores. The brine permeability of the core material varied between 67 and 130 mD. The core materials were classified as weakly laminated (67 mD) to strongly laminated (130 mD). Foam was generated by co-injecting 0.5 wt% AOS and N₂ gas at 80% foam quality, and no oil was present. Foam was generated in all laminated low perm cores and was observed at high pressures (30, 120 and 280 bar) and at temperatures of 50 or 100 °C. Foam breakthrough in strongly laminated core material and moderately laminated core material differed from weakly laminated core. Early foam breakthrough was observed where medium- and strong lamination was present (<0.5 PV), whereas the weakly laminated core showed foam breakthrough close to the injection rate.

Heterogeneous reservoirs with large permeability contrasts within the reservoir can give areas of poor sweep during gas injection or water flooding. Foam can be used to divert fluid flow to low permeability areas by blocking or strongly reduce fluid mobility in high permeable areas.

An important evaluation for foam formation in heterogeneous reservoirs seems to be the fact that fluid distribution is controlled by the existing reservoir permeability contrasts and that surfactant is therefore distributed mainly in high permeable areas (Di Julio and Emanuel 1989; Casteel and Djabbarah 1988). Di Jullio and Emmanuel reported two base case parallel corefloods performed by simultaneously water flooding both cores, then injecting water and CO₂ alternately (WAG). Average oil recoveries for the two base cases for low permeability core (LPC) were 0 and 0.4% OOIP for the waterflood and CO₂ WAG, respectively, and LPC was almost unswept by water flood and CO₂ injection. Foam was able to divert CO₂ to the low permeability core. Another paper reports in situ foam generation as an effective method for increasing supercritical CO₂ displacement efficiency and found foam to be most effective when CO₂ had displaced oil from the more permeable core in their dual core floodings of low-

and high permeable cores. In fact, during open CO₂ injection they observed no oil production from the low permeable core (Casteel and Djabbarah 1988).

From the literature, it is discussed that foam is stronger in high permeable core material. In foam field application, this can be an advantage because these areas are already swept to some lower oil saturation value and this can give increased foam stability.

Foam has also been used for diversion of acid in stimulation jobs (Parlar et al. 1995; Burman and Hall 1986) and reports successful foam diversion of HF acid when treating inorganic damage removal in the Gulf of Mexico.

5 Foam Stability

Bulk foam oil interactions have been studied for the AOS_{14–16} surfactant. It was found that a negative spreading coefficient is not a necessary condition for stable foams. Foam stability was related to transport properties within the foam, larger alkanes were found to stabilize the foam, and this may be connected to solubilization. The hydrocarbon molecular weight seems important for foam stability and decane and shorter alkanes solubilize in the micelles and destabilize the foam (Vikingstad et al. 2005). Calculation of the spreading coefficient for six crude oils showed positive values for the AOS surfactant, but static foam tests showed that the AOS generated stable foams in the presence of some of the crude oils (Vikingstad et al. 2006).

The foam-assisted WAG (FAWAG) has been a large-scale demonstration of foam for mobility control at the Snorre field in the North Sea. The Snorre reservoir pressure is 300 barg, and the temperature is 90 °C. Foam has been applied at the Snorre field both for gas shut off and thereafter as two large-scale mobility processes and the results from the last foam trial on the Western fault block were very conclusive (Svorstøl et al. 1997; Blaker et al. 2002; Skauge et al. 2002; Aarra and Skauge 2002).

The SAG injection method was applied when injecting surfactant solution and gas in Western Fault Block (WFB). A total of 140 tons surfactant was injected into the reservoir separated in two slugs. Interpretations of gas injection periods for the well pair P32–P39 would have suggested gas breakthrough time of less than 29 days, whereas the data after foam injection indicated at least a 5-month period until the injected gas arrived in the production well. Gas/oil ratio was significantly lowered compared to pre-foam GOR development which implies that large volumes of gas have been stored in the reservoir.

In interpreting the foam pilot in the Cusiana field, Rossen et al. (2017) discussed foam dry-out as an important factor in foam weakness. Simulations performed for the foam pilot in WFB showed sensitivity to (1) foam strength (2) foam dry-out (3) oil tolerance and (4) adsorption.

Field applications of foam for gas shut off in production wells to reduce gas/oil ratio have shown that the foam stability can last for a long period of time. Different foam generation methods have been applied in pilot successes. The injection method has involved both injection of pre-generated foams and SAG injection to generate foam in situ (Thach et al. 1996; Aarra et al. 1996; Chukwueke et al. 1998).

In some of these cases, a polymer has been added to the surfactant phase to increase the stability of the generated foams. Our experience with polymer-based foams (PEF's) showed that foam gas blocking performance could be increased by adding polymer to the surfactant phase. Experiments were run in a 91 cm North Sea reservoir core at 290 bar line pressure and at temperatures from 70 or 100 °C. The permeability of the composite reservoir core model was 1.7 D.

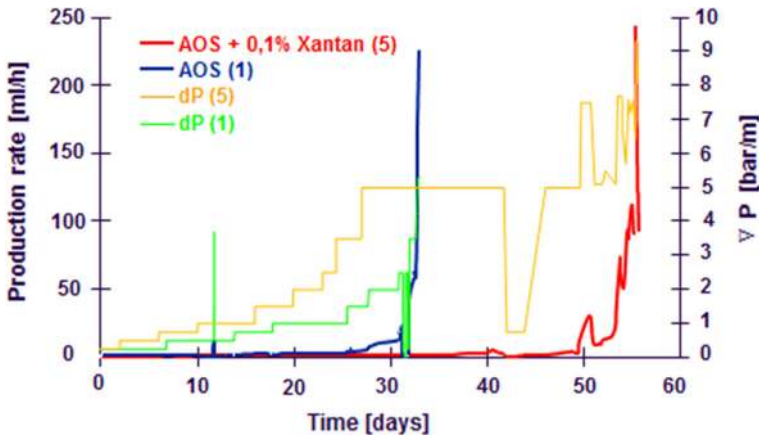


Fig. 6 Gas blocking by foam at different methane pressure gradients

Foam was generated by co-injecting AOS_{14–16} surfactant solution (or AOS + 0.1% polymer) and methane gas into the composite core model at 65% foam quality and total injection rate of 40 ml/h (Aarra et al. 1997) at residual oil saturation after gas flooding ($S_{org} \sim 0.1$ PV). Strong foams were generated, and foams ability to block gas was investigated by applying different methane pressure gradients and monitoring the production rate. Figure 6 shows the gas production rate as a function of the applied pressure gradient, and results show improved stability for the AOS + Xanthan foam compared to AOS alone. The applied pressure gradients applied in these experiments are also higher than typical field pressure gradients.

Even after 40 days of methane injection at high-pressure gradients, the production rate was below 3 ml/h. The pressure gradient was increased to 9 bar/m and the production rate increased significantly. Reducing the pressure gradient to 0.5 and 0.75 gave low production rates thus showing that the foam was not broken, or that some foam had been regenerated.

In a previous paper, we investigated the ability of foam to reduce seawater permeability and the longevity of reduced seawater permeability (Aarra et al. 2014). The foam core flooding experiments were performed without oil to better compare CO₂-foam properties to N₂-foams, and the influence of mass transfer on foam stability for CO₂ foams was studied.

In this study, seawater blocking experiments were performed after ending the foam generation sequence. Seawater was injected at 8 ml/h (equal to the surfactant solution rate during foam generation), and the seawater permeability was measured at different times and involved injection of several pore volumes of seawater.

For N₂ foams, the effect on seawater relative permeability development with pore volumes water injected was studied both at 30 bar and at 280 bar and showed an apparent seawater permeability ($k(ssw)/k(100\% \text{ seawater})$) was below 0.1. The effect was long lasting and significantly stronger in the presence of foam compared to no surfactant cases.

The use of equilibrated fluids made a great impact on the ability of CO₂-foams to reduce seawater permeability. When using non-equilibrated fluids, high water permeability with foam present in the core was measured. Probably, mass transfer between fluid phases and especially CO₂ dissolving in the injected brine was spontaneous according to Gibbs free energy and led to reduced foam stability and increased water saturation as using equilibrated fluids changed the situation completely even at 30 bar. In these experiments, CO₂ was saturated with brine and the 0.5 wt% AOS surfactant solution and also the synthetic seawater were

saturated with CO₂. The presence of equilibrated CO₂-foams in the core gave a strong and long-lasting reduction in seawater permeability as shown in two independent experiments.

This long-lasting reduction in seawater permeability after foam can, in our opinion, not be explained as an ordinary two-phase effect. Without foam present in the core, the seawater permeability increases until trapped gas saturation (S_{gt}) has developed. The reduction in k_{rw} depends on the magnitude of S_{gt} and the seawater relative permeability curve, but we believe that the large decrease in water permeability exceeds expected changes in S_{gt} (Skauge 1996; Skauge and Larsen 1994). There are some observations in the literature of water fingering through the foam (Nguyen et al. 2009) and we cannot exclude that this phenomena also can be present in our experiments.

6 Conclusions

Foam is generated at low surfactant concentration even below the CMC (critical micelle concentration).

In situ generation of foam is complex and difficult in oil wet carbonate rocks, where continuous oil films may occur. Foam generation is dependent on available water wet nucleation sites to form foam bubbles.

Foam propagation in porous medium has been summarized, and propagation rate for a given experiment seems to be constant. Laboratory studies confirm a foam propagation rate of 1–4 cm/day. Lower MRF may accelerate the foam propagation.

Past and present field trials on foam lack information about the rate of foam propagation, and future field pilots are encourage including observation wells in order to gain information of field-scale foam propagation.

Stability of foam has been studied in laboratory and field tests, and data confirm long-term stability of foam. The potential economic benefit of using foam in relation to various process optimizations for EOR can be substantial as the operational cost is low. The foam processes, both production- and injection well treatments, are considered rather low-cost processes. We encourage the oil industry to use foam further to improve the economics of their mature oil fields.

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