Laboratory Cost-effective Methods to Evaluate CO2-Foam Behavior at Reservoir Conditions

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ABSTRACT

Reducing CO2 emissions can be achieved through utilization of the less emitting energy resources as well as by increased consumption of the emitted CO2 through different applications including sequestering CO2 into subsurface formations. Deep subsurface formations such as depleted oil/gas reservoirs, basaltic formations, coal seam beds, and saline aquifers provide various opportunities for CO2 sequestration. One of the major challenges facing the CO2 injection is its poor volumetric sweep efficiency which is attributed to the low density and viscosity of injected CO2 compared to the reservoir fluids.

One promising method to improve CO2 sweep efficiency and, eventually, storage efficiency is the use of foam. Surfactants are mostly used to lower CO2-brine interfacial tension and generate foams. Usually high-pressure and temperature (HPHT) methods like core flooding are used to understand behavior of foams and foam producing chemicals at close to reservoir conditions, but unfortunately these methods are time-consuming and expensive to operate. The objective of this work is to evaluate foam behavior using HPHT robust surfactant screening equipment. These equipment include: foam rheometer (to study foam rheological properties), foam analyzer (to study certain foam characteristics such as bubble size and count, foam structure, and foam half-life), and microfluidics device (to understand the mechanisms and impact of added surfactants during CO2 and brine two phase flows in porous media in pore-scale level). They are capable of screening CO2 foam surfactant under reservoir conditions (HPHT) quickly and cost-efficiently. Several surfactants formulations are tested using those equipment. The selected chemicals are suitable for applications in high salinity and high temperature reservoirs.

Presented methods and laboratory equipment offer a significant advancement in the initial screening of foaming agents, especially when a large number of formulations need to be evaluated.

Keywords: CCUS, CO2 Foam, Cost-Effective, Gas Mobility, Micromodel

NONMENCLATURE

Abbreviations

$\mu_{apparent}$	Foam apparent viscosity
τ	Shear stress
γ	Shear rate
D	diameter
ΔP	Pressure drop
L	length
V	Velocity

1. INTRODUCTION

Conventionally gas injection is a well-known method to effectively improve EOR including both hydrocarbon and non-hydrocarbon gases, such as Carbon dioxide and Nitrogen[1]. When miscibility is present between the injected gas and the reservoir oil, there is a major advantage as most of the oil produced in the zone is swept by the gas, increasing the yield of oil recovery[2]. CO2 is a wildly prominent gas used for EOR due to its dual benefits[3]. The environmental impact of the footprint of CO2 is greatly decreased as it offers a method of carbon sequestration due to subsurface injection[4]. It also technically enhances oil recovery such as oil swelling, viscosity reduction, vaporization and extraction of portions of crude oil[5-7].

However, despite the many advantages of injecting CO2, when it is compared to other reservoir fluids it has poor sweep efficiency due to lower viscosity, density, and poor reservoir performance. These properties can result in reducing overall efficiency caused by unfavorable issues such as, gravity override, viscous fingering, channeling, all leading to an increase in the gas to oil ratio (GOR)[5,8-13].

Many mobility control methods have been tested to try and address these limitations such as incorporating water-alternating-gas (WAG) process, CO2 foam injection, and CO2 thickeners[14-17]. However, each of these do propose some concerns regarding feasibility, cost, their effect on the environment, and potential safety hazards[18-22].

With that being said, the injection of CO2 foam is considered the most promising technique to overcome the low gas viscosity challenges[15,23]. The definition for foam is the gas dispersed in a continuous liquid phase[24]. Carefully created CO2 foam in porous media can effectively enhances its apparent viscosity by decreasing its relative permeability. This leads to more control over CO2 mobility and as a result, sweep efficiency is enhanced during miscible CO2 flooding[15,25,26].

However, factors at reservoir conditions such as temperature, brine salinity, stability when interacting with crude oil, degradation after injection, and the ability for the surfactant to be absorbed all affect the effectiveness of the CO2 foam. To determine the adequate surfactant for CO2 foam flooding, it is essential to understand the CO2 foam behavior as it travels through porous media and the mechanisms of oil recovery during miscible flooding. This is essential to get the best EOR results. Another challenge that is faced during the injection of CO2 foam is that the CO2-philic tail is difficult to stabilize due to the fact that it's a poor solvent for surfactant tails[8,27-32]. The instability can occur as bubble coalescence or flocculation[33,34].

This paper aims to explore and demonstrate various laboratory methods that evaluate the CO2 foam behavior under HPHT conditions.

2. MATERIALS AND METHODS

2.1 Materials

Four foaming agents' surfactants were used in this experimental study. Commercially available cocamidopropyl betaine surfactant (Amphosol CG-50), lauramidopropyl betaine surfactant (Amphosol LB), and Sodium Alpha Olefin Sulfonate surfactant (Stepantan AS-12 46) used in this study were from Stepan Company. Also, a methanol foamer chemical from local vendor was used in this assessment. Synthetic brine with a total dissolved solid (TDS) content of 57,000 ppm, density of 1.01 g/mL and viscosity of 0.291 cP, both values were measured at 90 °C and used in this study. More details of the brine compositions can be found in Table 1.

Table 1: Synthetic brine (high salinity water) compositions

Ions	**Symbol**	**(ppm)**
Sodium	Na^+	18,300
Calcium	Ca^{2+}	650
Magnesium	Mg^{2+}	2,110
Sulfate	SO_4^{2-}	4,290
Chloride	Cl^-	32,200
Bicarbonate	HCO_3^-	120
TDS		57,670
Ionic Strength (mol/L)		1.146

2.2 Methodology

This work proposes a set of experimental tests designed to rapidly screen and select suitable foaming agents for field applications, eliminating the impact of fluid-rock interactions, which needs to be evaluated separately. Figure 1 outlines those recommended experiments.

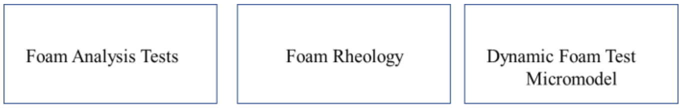


Figure 1: Foam Screening Tests

2.3 Foam Analysis Tests

The foam characteristics produced by individual surfactants and a blend of two surfactants in high salinity water were analyzed using a dynamic foam analyzer equipment. Experiments were conducted at ambient temperature and a pressure of 100 psi. A 50 mL of the prepared samples, as listed in Table 2, is poured into a glass column attached to a base holder. A porous filter with a pore size between 16 to 50 microns is placed between the glass column and the base holder. CO2 gas is introduced through the filter into the solution to generate foam. During each experiment, a 200 mL of CO2 is injected at a rate of 0.2 mL/min. foam formation occurred as the gas interacted with the surfactant solution. The analyzer's software then measured the number of bubbles, bubble size distribution, and foam volume reduction over time.

2.4 Foam Rheology

The foam rheological properties, mainly apparent viscosity, produced by dissolving surfactants in high salinity water is measured using foam rheometer apparatus. 0.50 wt.% of the active surfactant solutions were prepared and used to conduct the foam rheological measurements using a custom-made HPHT foam loop rheometer. A schematic of the system is shown in Figure 2. The foam rheological properties were measured using sc-CO2 under high pressure (1800 psi), high temperature (100^oC) and salinity conditions. The experiments were performed at different shear rates varying from 100 – 450 s^{-1}, and volumes of sc-CO2 to the total volume of liquid and gas (foam quality) used for was 70%.

When studying fluid rheological properties, it is important to characterize shear stress (τ) and shear rate (γ) to estimate the fluid apparent viscosity. Foam is classified as non-Newtonian fluid whose apparent viscosity is shear rate dependent. Apparent viscosity $\mu_{apparent}$ of generated foam was calculated as follow:

$$\mu_{apparent} = \frac{\tau}{\gamma} \tag{1}$$

$$\tau = \frac{D\Delta P}{4L} \tag{2}$$

$$\gamma = \frac{8V}{D} \tag{3}$$

Where D is the tube diameter, ΔP is the differential pressure across the foam loop, L is the tube length and V is the velocity.

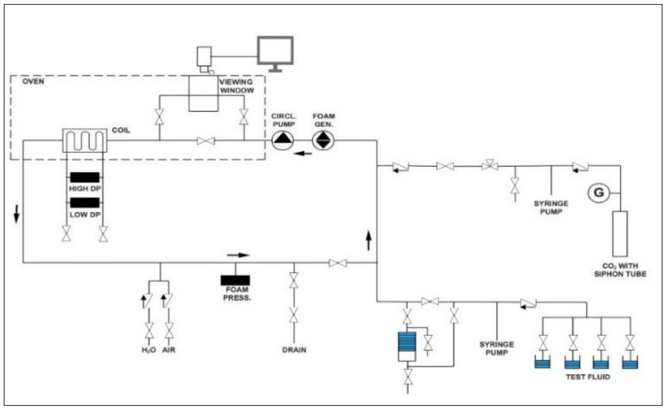
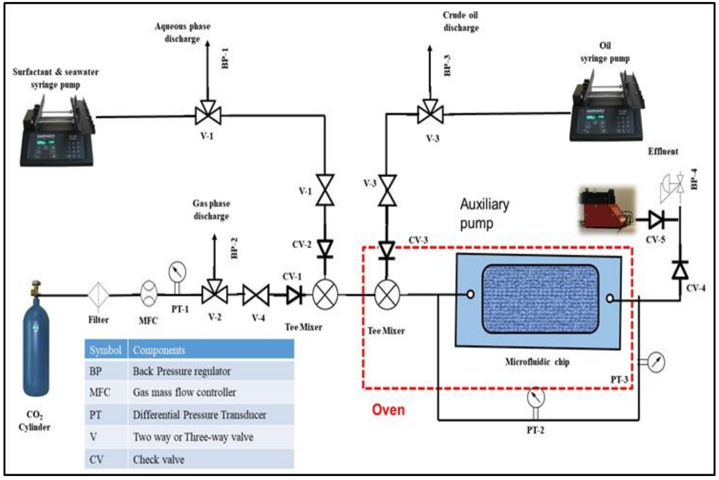


Figure 2: Schematic of the Foam Loop Rheometer

2.5 Dynamic Foam Test (Micromodel)

Foam in porous media has different behavior and characteristics than that produced in bulk. The strength of the CO2 foams in porous media was evaluated using two surfactants, Surfactant A (Amphosol LB) and Surfactant D (Amphosol CG-50). measured using the microfluidic device. A microfluid system, shown in Figure 3, was used to measure foam behavior in porous media. The pressure drop across the microfluidic chip was measured for the two mentioned surfactants. 0.20 wt.% surfactant solutions in high salinity water were prepared as described previously. CO2 gas and the surfactant solution were co-injected into the microchip. The back pressure of the system was set to 100 psi and experiments were conducted at 100^oC. For each test, the microfluidic chip was flushed with several pore volumes of brine to ensure the removal of any trapped air or surfactant inside the system, followed by the injection of the surfactant solutions. The pressure drop across the chip was measured at different foam qualities: 30, 60, and 80%. The total injection superficial velocity was controlled at 640 ft/day.



Symbol	Components
BP	Back Pressure regulator
MFC	Gas mass flow controller
PT	Differential Pressure Transducer
V	Two way or Three-way valve
CV	Check valve

Figure 3: Microfluidic System

3. RESULTS AND DISCUSSIONS

3.1 Foam Analysis Results

The use of this advanced equipment could help in selecting the suitable foamers at certain conditions. This equipment provides scientifically the major foaming parameters which could help in screening and selecting proper foaming agents for certain applications. These parameters include foam height and volume, foam half-life, bubble count, and foam structure. In this section, an example is presented to clarify how this equipment, as part of suggested workflow, can quickly help in assessing foaming behavior.

Longer foam half-life and fine-textured foams (with high bubble count) offer more stable foams and eventually, more resistance for gas to flow in porous media. Conducting coreflooding experiment is a resource-intensive process that demands substantial time, chemical usage, and manpower. AlYousef et al. [32] studied the impact of mixing surfactants on foam behavior by obtaining essential foaming parameters using a cost-effective method. Two surfactants as shown in Table 2, Surfactant A (Amphosol LB) and Surfactant B (Stepantan AS 12-46), were used to perform this study.

Table 2: Different Mixing Ratios of Surfactant A and B

Solution	Surfactant	Content %
1	A	100% A
2	A+B	80% A & 20% B
3	A+B	50% A & 50% B

Comparative images of foam structure and bubble count of the foams generated using CO2, and the selected foaming agents in high salinity water are shown in Figure 4 at a given interval of time. The results showed that mixing surfactants can significantly enhance foam texture and foam stability. In addition, there is a certain mixing ratio at which the highest foam stability can be achieved. Based on the selected ratios, the results demonstrated that mixing 80% of Surfactant A with 20% of Surfactant B resulted in the highest foam bubble count and the smallest bubble sizes as shown in Figure 4 and Figure 5. The averages bubble count for the foam generated using Surfactant A, mixing 80% A & 20% B, and mixing 50% A & 50% B are 55, 105, 18 bubble/mm2, respectively.

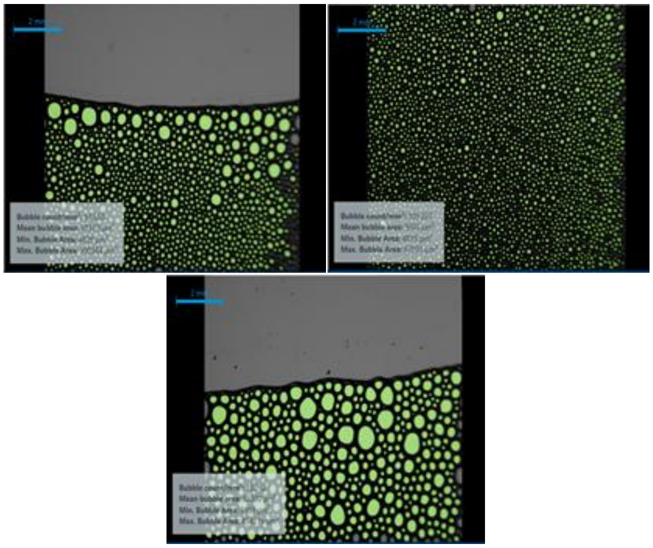


Figure 4: Bubble Count and Foam Structure after 50s of Foam Generation a) 100% A, b) 80% A & 20% B, and c) 50% A & 50% B

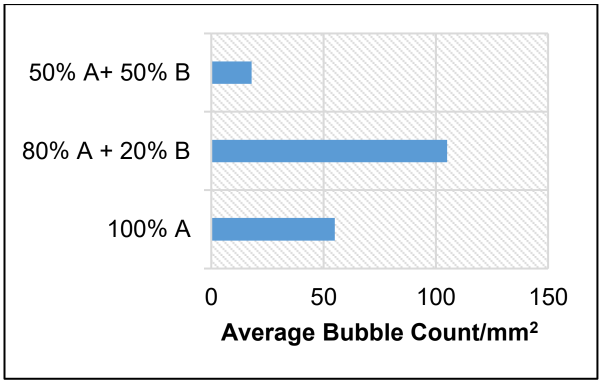


Figure 5: Average Bubble Count after 50s of Foam Generated using Surfactant A, mixing 80% A & 20% B, and mixing 50% A & 50% B

The foam half-life can be also measured as well to provide information about foam stability. a longer half-life implies greater foam stability, meaning the foam maintain its structure and effectiveness for longer period. The resulted, presented in Figure 6, showed that the foam half-life values for the three cases: Surfactant A, mixing 80% A & 20% B, and mixing 50% A & 50% B are 103, 150, and 97, respectively.

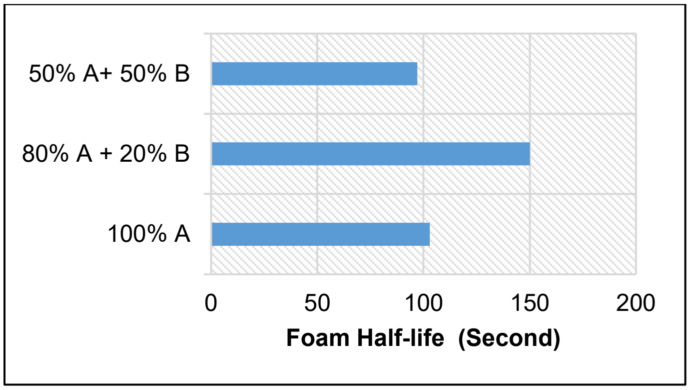


Figure 6: Foam Half-Life for Foam Generated using Surfactant A, mixing 80% A & 20% B, and mixing 50% A & 50% B

3.2 *Foam Rheology Results*

Foam rheological properties of different surfactants can offer a quick method to select and screen potential foaming agents for field applications. Foam rheology describes the flow behavior (viscosity, elasticity, shear-thinning properties …etc.) of foam, especially under varying reservoir conditions including pressure, temperature, and shear conditions. More viscus foams are more stable and have more potential to resist harsh reservoir conditions and could propagate further in porous media. Foam rheological properties of different surfactants can offer a quick method to select and screen potential foaming agents for field applications.

Foam rheological properties of three surfactants, Surfactant A (Amphosol LB) and Surfactant C (Methanol Foamer), were measured at 1800 psi and 100°C, and 70% foam quality. The results, as shown in Figure 7, demonstrated that Surfactant A has a larger apparent viscosity compared to Surfactant B and Surfactant C when measured at various shear rates. The difference between in apparent viscosity between Surfactant A and Surfactant B is the range between 15-60%, while the difference between Surfactant A and Surfactant C is in the range between 50-60% In addition, the foam exhibits a shearing-thinning behavior; foam viscosity decreases as shear rate increases. The results suggest that foam rheological properties can serve as a rapid screening method for evaluating foaming agents in various field applications.

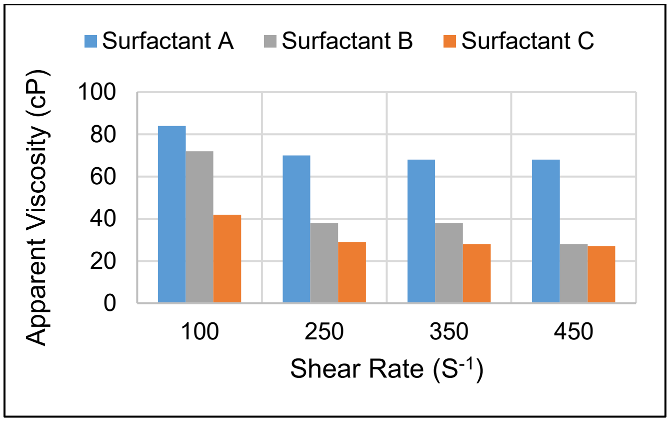


Figure 7: Foam Rheological Properties for Surfactant A and Surfactant C Measured at 1800 psi and 100oC

3.3 *Dynamic Foam Test (Micromodel)*

A microfluidic system to assess foam behavior in porous media is a miniaturized platform that mimic the structure and flow properties of porous rocks, allowing to visualize and quantify foam behavior at the pore scale level. Steady state pressure drop values measured across the microfluidics chip as a result of the generated foam within the porous structure of microfluidic chip at different foam qualities (30%, 60%, and 80%) were recorded. Higher pressure drops correspond to higher resistance to gas flow and, hence, foams with higher viscosity. The CO2 foam strength and stability using two surfactants, Surfactant A (Amphosol LB) and Surfactant D (Amphosol CG-50) was measured using microfluidic device. As shown in Figure 8, the average steady state pressure drop for Surfactant D is higher than that recorded when Surfactant A was used. Also, the results revealed that the highest pressure drop recorded for both surfactants is when the foam generated at 80% foam quality, and the lowest is when the foam generated at 30% foam quality. Similar to the previous presented methods, the results suggest that dynamic foam test using microfluidic system can serve as a rapid screening method for evaluating foaming agents in various field applications.

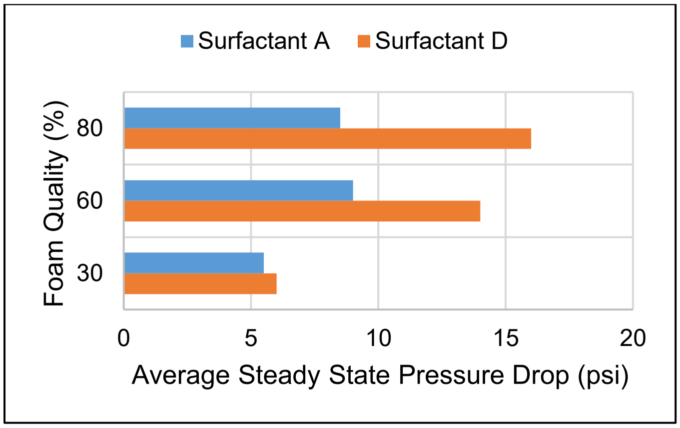


Figure 8: Average Steady State Pressure for Surfactant A and Surfactant D Measured using Microfluidic System

4. CONCLUSIONS

The goal of this study is to assess foam behavior using HPHT equipment designed for robust surfactant screening. The tools utilized include: foam rheometer (to study foam rheological properties), foam analyzer (to study certain foam characteristics such as bubble size and count, foam structure, and foam half-life), and microfluidics device (to understand the mechanisms and impact of added surfactants during CO2 and brine two phase flows in porous media in pore-scale level). These systems could be employed to generate critical data, aiding in the evaluation and selection of suitable foaming agents for filed applications. The approach outlined is not only effective for rapid surfactant screening and understanding foam transport dynamics but also offers valuable foam parameters that can be used in simulations to assess the feasibility of CO2 foam in a specific reservoir during the early stages of experimental planning.

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DECLARATION OF INTEREST STATEMENT

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper. All authors read and approved the final manuscript.

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