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An Investigative Study of Oil Foamers/De-foamers to Boost Crude Oil Production in Brownfields

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Abstract

In some occurrences, medium and heavy oil fields - even those ones with low BS&W - may lack the ideal amount of gas for optimized gas lifting operations. In general, the low GOR is the main culprit for such hurdle. Anyway, the gas scarcity ends up causing - a partial or even total - reduction in the overall production throughput - due to the liquid loadup phenomenon in the well. Moreover, this may potentialize undesirable flow destabilization (slugging) problems. Contrarywise, such brownfield scenarios, might be a picture-perfect niche for the use of crude and/or water foaming additives (foamers). Questionably, these foamers show the ability to boost production without requiring a higher gas (lift) flow rate at all. These surface-active chemicals are likely to operate by two mechanisms: reducing the hydrostatic head in the well (de-liquefying) and mitigating the friction losses in the flow lines.

There are more than a few foaming additives in the production chemicals market to de-liquify gas wells, as well as reliable analytical methodology to assess the efficiency of these products, and their impact on primary processing. It is also important to pinpoint that the pressure drop reduction and/or the production gain granted by these additives can be both precisely simulated with the help of field-proven thermohydraulic simulators.

In this investigative study, a standard laboratory methodology to assess foam stability was adapted to evaluate the performance of an open alkyl amidopropyl betaine (AAPB) formulation, a well-known water-foamer, that to our best understanding has never been used to foaming crudes with high BSW; and, as well, two water de-foamers (polymethylsiloxane) formulations, which were used to neutralize the AAPB foaming ability. The laboratory results of this investigative study and the impact of these chemicals on primary oil processing, TOG value, and flow-assurance related issues are also presented.

Keywords
Liquid Loadup; Foamers; De-foamers; Well de-liquefying, open alkylamidopropyl betaine formulation, polymethylsiloxane

Introduction

As reservoir fluids are continuously produced along the well's lifetime exploitation process, an unavoidable reservoir depletion process takes place. To keep this process at bay, reservoir-, completion-, artificial lift -, and flow assurance-engineers must work in concert to design, and apply, a suite of tailor-made solutions to mitigate flow assurance problems and the natural production decline; maintain the highest possible production level along the production time; and, last but not least, enhance the reservoir recovery factor. Due to that, the oil industry has been developing and/or adapting a myriad of flow assurance solutions to maximize oil-recovery, such as innovative lifting-, and well-workover techniques or methods, all-oriented to cope with the inescapable reservoir depletion issue. For instance: the injection of different fluids into reservoir to build up its pressure; optimization of pumping & boosting technologies and artificial lift methods, exhaustive use of multi-phase simulation, usage of different production approaches & strategies, just to mention a few examples. Arguably, these technical efforts have ended up producing a myriad of tailored-made solutions now available for field application in different métiers.

Liquid load-up is a recurrent phenomenon observed during the later lifetime of a well, when a column of fluid - either water, oil condensate, or both, ends up accumulating at the bottom part of a vertical - or almost vertical - gas or oil well, thereby creating a hydrostatic head higher than the existing bottomhole reservoir pressure. Where there is no way to increase either the existing gas-lift capacity or the existing pumping capacity, the well will inevitably halt its production. Using an oilfield lingo, either an oil or a gas well under such a situation is said to be “killed” by the hydrostatic head created by the liquid column inside of it. Turner et al[1], who addressed the liquid loadup problem back in 1969, derived a pivotal equation, based on the equilibrium of forces acting on a liquid droplet floating in the gas stream flowing upward the well, to estimate the minimum (critical) gas velocity needed to transport this oil droplet up to the surface. Debatably, those authors brought together for the first time in the literature an equation to quantify this critical (minimum) gas transport parameter.

Chemical foamers for foaming either aqueous- or oil-condensate-fluids, which can accumulate inside brownfield gas wells have been used in the North Sea area since the beginning of 1980s, and thus became popular around the world afterwards. One may say that when it comes to chemically - deliquefying a gas well, the usage of foamers might be a solution of choice. Currently, more than a few chemical gas foamers (surfactants + solvent blends), produced by different chemical suppliers, are available in the oilfield chemistry market[1]. Conversely, not many oil-foamers have been developed yet by the chemical manufacturers, although there are many brownfield scenarios in which these products could be potentially used. Without doubt, there is a demand for oil-foaming products for subsea injection. However, besides being suitable for subsea application, they must also show a minimum impact on the gas-liquid and liquid-liquid separation processes. In fact, only recently a few commercial oil-foamers were developed specifically to de-liquify crude oil wells.[2,3,4].

A scoping trial was carried out in our laboratory to evaluate a natural product (alkyl betaine) derivative: the chemically- modified amidopropyl betaine (AAPB), which is a pH-sensitive amphoteric surfactant widely used in the cosmetics industry, and crude production operations, as foaming agent for aqueous systems. Both chemical molecules are depicted in Figure 1.

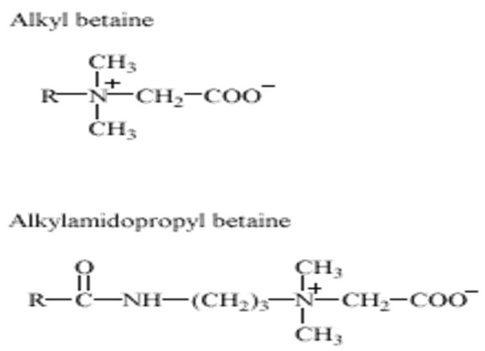


Figure 1 – Alkylbetaine and the amphoteric surfactant alkyamidopropyl betaine (AAPB) molecular structures (Source: Danish Environmental, access: 02/May/2022)

According to our experience, AAPB can work as a foamer in crude oils which show a high BS&W value (>60%) and is also suitable to de-liquify medium- and heavy-crudes. Therefore, the foaming efficiency of AAPB in NaCl brine was determined in our laboratory with the aid of well-known analytical assays used for foaming studies. As a matter of fact, the goal is to assess the overall impact that this kind of additive may have on the topside water-oil separation processes.

Methodology

Materials

Briefly, in this experimental work, a commercial (open-formulation) sample of AAPB was used as received. A saline solution containing 100g of NaCl/L, was prepared in the laboratory with analytical-grade NaCl and deionized water (test solution). Two commercial de-foamers were also used in the experimental work. They were both used as received: -polymethylsiloxane, @ 30% in solvent and - polymethylsiloxane @ 10% in emulsion. Commercial oil demulsifies were used as received. Finally, a crude oil emulsion from an offshore field, composed by a medium API degree crude (31.6°API) and 32% BS&W, was also used in the experimental work.

Experimental Procedures

The foaming action of AAPB (@ 5,000 ppm) - in the presence of two de-foamers (@ 500 ppm) - was investigated in the test solution, under a continuous nitrogen gas flow (30NL/h), through a sparging porous medium made of sintered glass, as specified by the ASTM D8920-03[5] (standard test method for foaming characteristics of lubricating oils). All the tests were carried out at room temperature. The amount of test solution used in the assays was 100 mL and the internal volume of the graduated glass cylinder is1000 mL. The maximum height of the foam, or the time required for the foam to overflow the glass cylinder, was quantified and, in the latter case, the total mass of overflowed liquid was also measured. The time for total foam breakdown was also quantified.

The effect of the AAPB foamer on emulsion stability and the water-oil separation process was evaluated by mixing 100 mL of the field crude oil emulsion and 50 mL of the test solution with or without 5,000 ppm of alkyl AAPB, at a temperature of 60°C. The fluids were manually mixed and then sheared with the aid of an IKA Ultraturrax T-25 homogenizer operating at 8,000 rpm for 1.5 minutes. An amount of 200 ppm of a commercial demulsifier was added to the formed emulsion, which was stirred for additional 20 seconds. Then, the fluids were poured into laboratory glass beakers and the kinetics of gravitational separation of water was monitored for 10 minutes. The quality of both oil and water phases was visually assessed as well.

Equations used to Evaluate Foamer Performance

To determine the foaming action of AAPB in the presence of two de-foamers, the foam percentage (F (%)) was calculated, according to Eq. 1, while the percentage of overflowed mass (OM (%)) was calculated according to Eq. 2.

F (%) = (VE – VL)*100/VL (1)

where:
-VE is the volume of foam, and
-VL is the volume of liquid.

OM (%) = OM*100/IM (2)

where:
- OM is the overflowed mass and IM;
- The initial mass of saline solution added with the foamer, with or without the defoamer.

To determine the effect of the foamer on the water-oil separation, the separated water percentage (WS (%)) was calculated according to Eq. 3.

WS (%) = WS*100/IW (3)

Where:
- WS is the volume of water separated in time;
- IW is the amount of initial water

Results and Discussion

The lab apparatus for evaluating the performance of AAPB and the de-foamers is shown in Figure 2

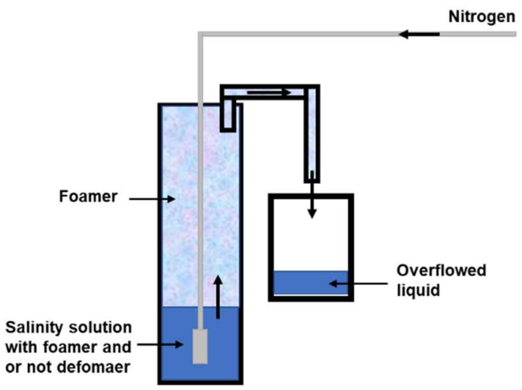


Figure 2. Lab apparatus used for evaluating the foaming action of the AAPB foamer in the presence of field-applied defoamers.

Table 1 presents the results of the foaming action of AAPB in the presence of the defoamer agents in the test solution, at room temperature. AAPG concentration: 5,000 ppm. Defoamer concentrations: 0 and 500 ppm. Nitrogen flow rate: 30NL/h.

Table 1. Results of the foaming action of AAPB versus the performance of antifoaming agents to prevent its foaming action

Properties	Brine containing 5,000 ppm of foamer: Without defoamer	500ppm of solvent-based defoamer	500ppm of emulsion-based defoamer
Foam (%)	Overflow (>900%)	Overflow (>900%)	27
Overflow (min)	1.5	2	no overflow
Overflow mass (%)	20.7	17.3	
Total time for foam breakdown (min)	85	13	0.17

From Table 1, it is possible to conclude that the test solution containing 5,000 ppm of AAPB can produce a rapid and large amount of foam, and that this foam proved to be very stable. It is also possible conclude that the addition of 500 ppm of the solvent-based de-foamer, was not able to reduce:

- the speed of foam formation;
- the amount of foam formed;
- the overflow time. and;
- the mass of liquid transported.

Conversely, the emulsion-based defoamer was able to:

- significantly reduce the total foam break time,
- to drastically reduce the amount of foam formed, not allowing overflow, and;
- drastically reducing the total break time of the foam formed.

According to these results, it is possible to conclude that the emulsion-based defoamer was more efficient than the solvent-based one to prevent the foaming action of AAPG.

The results of the effect of AAPB foamer on emulsion stability and on the water-oil separation process are presented in Table 2.

According to Table 2, It is possible to conclude that the presence of 5,000 ppm of AAPB in the test solution was able to reduce the kinetics of water separation and deteriorate (visual observation) the quality of the separated water.

Because of the results presented in Table 2, a new suite of tests was carried out to evaluate the effect of lower foaming dosages on the stability of the emulsion and on the water-oil separation. This new suite of tests was performed at 60°C, and 200 ppm of demulsifier. These results are shown in Table 3.

Table 2. Results of the effect AAPB foamer on emulsion stability and on the water-oil separation process at 60°C (200 ppm of demulsifier added to the emulsion)

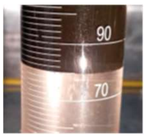
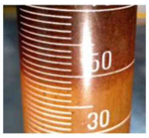
Time (min)	Water Separated (%) as a function of time	
	without AAPB	with 5,000 ppm of AAPB
2	48.8	26.8
4	97.6	53.7
6	97.6	80.5
8	97.6	87.8
10	97.6	90.2
Phases appearance after 10-minute separation time		

Table 3. Results of the effect of lower AAPB dosages on the emulsion stability and water-oil separation at 60°C, and with 200 ppm of demulsifier.

Time (min)	Water Separated (%)	
	100 ppm of AAPB	500 ppm of AAPB
2	0.0	0.0
4	18.3	12.2
6	36.6	30.5
8	63.4	63.4
10	75.6	75.6
Phases appearance after 10-minute test time		

From data presented in Table 3, the reduction of AAPB concentration, from 500 ppm to 100 ppm, in the test solution, did not cause any remarkable effect on the water separation kinetics. However, it can be visually observed, there is a somewhat improvement of the separated water quality with the reduction of the foamer dosage.

When comparing data from Tables 2 and 3, it is possible to conclude that the reduction of the AAPB dosage from 5,000 ppm to 500 ppm, and then to 100 ppm, also reduced the water separation kinetics. However, there was no visually observed improvement in the water quality. Arguably, both the observed water separation profile and the emulsion separation kinetics is provoked by the straightforward fact that AAPB, in addition to foaming, is an effective oil-in-water emulsifying additive.

Conclusions

Many medium- and heavy-oil fields lack the ideal amount of lifting gas, even those ones with low BS&W. This inevitably leads to severe (or total) production losses, besides potentializing slug flow problems. Such scenarios, however, are good candidates for the use of crude foaming additives, which could eventually help reducing friction losses in the production system, and slugging production events, thus boosting crude oil production.

Currently, the market of crude foamer chemicals has not many options suitable for flow assurance applications in subsea scenarios, where injection via gas lift or chemical umbilical is mandatory.

It is of paramount importance that foaming chemicals show a good foaming and de-liquefying characteristics for crude oil wells with or without a high water cut. Likewise, these chemicals should not present detrimental effect on the primary crude/water separation, nor in the processed fluids.

Arguably, some brownfields, even with low BS&W, could benefit from the application of foaming products for well de-liquefying and/or liquid holdup removal. As a matter of fact, we are looking forward to organizing an inventory of candidate wells to the foaming technology. The primary results of this search indicate there are a few brownfields located in offshore scenarios that could be a good niche for the application of such technology.

AAPB-based formulations show a good potential to be used as flow assurance foaming agents for de-liquefying crude oils with high BS&W. However, it is necessary to assess the detrimental effect that this product - or any other - may have on gas-liquid and water-oil separation during the primary crude oil processing.

It is necessary to improve, adapt and standardize the existing analytical methods to better select foaming agents for de-liquefying crude oils, and to assess the impact of these products on primary oil processing. Obviously, these methods must represent – as close as possible – the actual field conditions.

A case-by-case approach still must be used to select crude foamers and/or de-foamers for a given crude oil/production system. Unfortunately, this issue remains in the art domain. Therefore, it is our objective to extend this investigative study to continue studying/searching for crude oil foamers as a tool to boost the production in brownfields.

From our point of view, the novelty of this technical contribution is the concern that the addition of chemical foamers to produced oil can jeopardize both topside process & TOG parameters. Should a crude oil foamer be added to crude oil upstream the topsides , it is of paramount importance to carefully monitor the topside´s operational parameters and not rule out the need to make up the topside´s defoamer dosage.

In the authors view the use fo AAPB to foam crudes with high BSW is a technical innovation as well.

Last but not least, the contribution of chemical supply companies was of paramount importance to achieve this goal.

Competing Interest Statement

The authors state that they do not have any kind of personal association or financial aids that could have appeared to affect the results of the work presented in this technical contribution.

Responsibility Notice

The authors are the only responsible for the paper content.

Acknowledgments

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