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FOAMY OIL TRANSPORT AS A MULTIPHASE FLOW SYSTEM

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ABSTRACT

In some heavy and extra heavy oil production fields in Venezuela the oil production occurs due to the gas in solution, which tends to form a foam, consisting of a dispersion of gas and water in oil. Foamy oil behavior at reservoir conditions and its transport process through porous media have been the focus of many multiphase flow researches. However, few studies have been developed at surface conditions, in which the oil viscosity increases considerably and the gas bubbles that are trapped in the foamy oil are expanded due to the change in pressure and temperature. Transportation of foamy oil through pipelines is a challenge in Venezuelan fields due to the relatively high gas volumes produced with oil. Part of this gas is dispersed as foam and the rest flows as a separate phase generating different flow patterns in the pipelines. This experimental study is focused on the behavior of a multiphase mixture composed by foamed emulsion, with high oil viscosity flowing through horizontal pipelines. The evaluated conditions correspond to 8.5 wt.% water, 1.5 wt.% surfactant and 90 wt.% mineral oil, pressures up to 255 kPa, temperature of 20°C, superficial gas velocities between 0.92 - 17.56 m/s and superficial liquid velocities between 0.04 - 1.07 m/s, with pipeline diameters of 0.0243 and 0.0508 m. Three different flow patterns were obtained: foamy stratified, foamy slug and foamy annular. Foaminess and foam stability were found to be dependent on the operational conditions. Foamability increases with the increment of the gas and liquid flow rates, while foam stability tends to decrease when the liquid flow rate increases and the gas flow rate decreases.

Keywords: foam, foam flow, three-phase flow, foam flow patterns.

TRANSPORTE DE CRUDO ESPUMANTE COMO UN SISTEMA DE FLUJO MULTIFÁSICO

RESUMEN

En algunos campos de producción de crudos pesados y extrapesados de Venezuela la producción de dichos hidrocarburos ocurre debido al gas en solución, el cual tiende a formar una espuma, constituida por una dispersión de gas y agua en el crudo. El comportamiento del crudo espumante a condiciones de yacimiento y su transporte en el medio poroso ha sido estudiado por múltiples investigadores en el área de flujo multifásico. Sin embargo, pocos estudios se han enfocado en su comportamiento a condiciones de superficie, donde la viscosidad del crudo aumenta y las burbujas que se encuentran dispersas incrementan su tamaño debido a los cambios en presión y temperatura. El transporte de crudo espumante es un reto en Venezuela debido a los altos volúmenes de gas producidos con el crudo, en el cual el gas fluye parte disperso en el crudo formando una espuma y otra fracción de gas separada, promoviendo la formación de diferentes patrones de flujos en las líneas de producción. Las condiciones evaluadas en este estudio corresponden a un 8.5% p/p de agua de, 1.5%p/p de surfactante y 90%p/p de aceite mineral de alta viscosidad, con presiones de hasta 255 kPa, temperaturas de aproximadamente 20°C, velocidades superficiales del gas entre 0.92 y 17.56 m/s, velocidades superficiales del líquido entre 0.04 y 1.07 m/s, en tuberías de 0.0243 y 0.0508 m de diámetro, obteniendo tres patrones de flujos diferentes: espuma-estratificada, espuma-tapón y espuma-anular. Adicionalmente, se encontró que la espumabilidad incrementa con el aumento del flujo de gas y líquido y la estabilidad de la espuma tiende a decrecer cuando el flujo de líquido aumenta y el de gas disminuye.

Palabras Claves: Espuma, flujo de espuma, flujo trifásico, patrones de flujos de espumas.

INTRODUCTION

Many heavy and extra heavy production fields in Venezuela are currently producing with water cuts up to 30%v/v and gas-liquid ratios up to 700 SCF/STB. A fraction of the gas and water is dispersed in the oil, forming what it is known as "Foamy Oil" and the other fraction exists as a continuous phase, forming a complex multiphase flow system, creating different flow patterns in the production pipelines. Understanding the behavior of this foamy oil flowing through pipelines is necessary in order to develop more accurate models for the design and evaluation of the multiphase flow systems used to transport these heavy oils at surface conditions.

GAS-OIL VERSUS GAS-OIL-WATER MULTIPHASE FLOW SYSTEMS

According to Shoham (2006), the single-phase flow hydrodynamics systems are well understood, however, the simultaneous flow of two fluids is considerably more complex due to the presence of the gas and liquid phase. For two-phase flow, it is necessary to consider operational variables as: gas and liquid flow rate, physical properties of the phases such as density and viscosity, and geometrical parameters as diameter and inclination angle of the pipe.

Ishii and Hibiki (2006) coincide with Shoham (2006) saying that developing the constitutive equations required to specify the thermodynamic, transport and chemical properties of the multiphase streams are considerably more complicated in comparison to single-phase flow due to the complex nature of two or more phases flowing together with a mobile and deformable interface, in which different flow patterns can be present. For the case of gas-liquid systems, according to Shoham (2006), different flow patterns can exist, in the case of segregated flow. It is possible to find stratified smooth or wavy flow at low gas and liquid flow rates, annular and annular wavy flow for very high gas flow rates, intermittent flow patterns, called slug flow or elongated bubbles, depending on whether there are gas bubbles dispersed in the slug body or not, and finally, the dispersed bubble flow which occurs at very high liquid flow rates.

Three-phase flow (gas/oil/water) is an area in which few efforts have been done, most of them focused in liquids with low viscosity. Açikgöz et al. (1992) conducted the first research about flow patterns in a horizontal pipe for gas/oil/water. Pan et al. (1995) did similar experiments and compared their results to the work of Açikgöz et al. (1992) and with the flow pattern prediction models proposed by Beggs and Brill (1973), and Taitel and Dukler (1976) for two-phase gas-liquid flow systems. Pan et al. (1995) concluded that these models are not appropriated for three-phase systems. Spedding et al. (2005) studied an oil/water/gas system and found different flow patterns depending on whether the systems are water dominated or oil dominated. In the case of oil dominated systems, which are the focus of this work, twelve flow patterns were identified and classified, depending on the gas-liquid spatial configuration and the oil-water configuration.

Three-phase flow systems for high oil viscosity is a topic that has been calling the attention of the multiphase flow research community recently. This is due to the significant reserves of heavy and extra-heavy oil (EHO), and the imminent production of gas and water caused by water coning or channeling in reservoirs or to vapor injection as predominant enhanced oil recovery method for oil production.

In 2009, Bannwart et al. studied three-phase flow in horizontal, vertical and inclined pipes with oil liquid viscosity of 34.95 Pa.s, identifying flow patterns similar to the ones found in two-phase gas/liquid flow. Poesio et al. (2009) studied the effect of introducing air in an oil/water system and tried to generate slug flow in the pipe, with oil viscosities of 0.9 y 1.2 Pa.s. They found that the increment in the total pressure drop is directly proportional to the superficial gas velocity in the pipeline and proposed a pressure drop model based on Lockhart-Martinelli model obtaining a good fitting. Wang et al. (2012) evaluated a three-phase flow system with natural gas/water and oil viscosity between 0.15 y 0.57 Pa.s and a relatively high pressure of 375 psig. They obtained experimental data of holdup in the pipe, pressure gradient and flow pattern which were compared against the unified model proposed by Zhang and Sarica (2006). They found significant discrepancies between the experimental results and the model predictions.

NON-AQUEOUS FOAM, FOAM EMULSIONS AND FOAMY OIL SYSTEMS

Salager et al. (2001) argued that in the EHO production systems gas bubbles appear below the bubble point and grow due to the gas expansion, but then coalescence process between the bubbles is not significant, unlike most oil production systems, where no surfactant action is possible as the gas-liquid interface is considered to be non-polar, and hence the inherent surface tension is at such a low level that there is little or no adsorption to the surface of hydrocarbon based surfactants (Friberg, 2010).

Salager et al. (2001) argued that for EHOs there is an efficient stabilization mechanism of the gas-liquid interface in the bubbles, driven by asphaltenes deposition on their surface, apparently inducing bubbles to be "armored" or "encapsulated". There is still a large controversy regarding the phenomenology of these foamy EHOs as it is not clear which the mechanisms that stabilize these non-aqueous foams are (Belandria, 2001).

According to Schmidt (1996), Edward et al. (1991), Belandria (2001) and Friberg (2010) the unusual stability of this type of foam could be associated to a steric mechanism, in which the solid particles form a crust around the bubble. Another alternative is to consider the effect of the high interfacial viscosity promoted by the presence of substances, liquid crystals deposited at the interface, and the low rates of drainage liquid film inter-bubbles.

Masatoshi et al. (2003), Shrestha et al. (2007), and Marcano et al. (2009) studied the effect of adding only water, and water and surfactants to non-aqueous foams. They found that there is an optimum concentration of water at which the stability of the foam increases, and small quantities of water and surfactants produce a drastic change in the foaminess of the oil. In addition, Marcano et al. (2009) concluded in their research, after trying to reproduce the mechanisms that form and stabilize the foam in the Venezuelan heavy crude oils, that the presence of dispersed water in oil is the responsible for their foaminess.

The hypothesis, presented by Marcano et al. (2009) in order to explain how the water stabilized the foam, is based on a water film surrounding the gas bubbles dispersed in the oil, resulting in a multiple emulsion, air/water/oil, stabilized by a surfactant as shown in Figure 1.

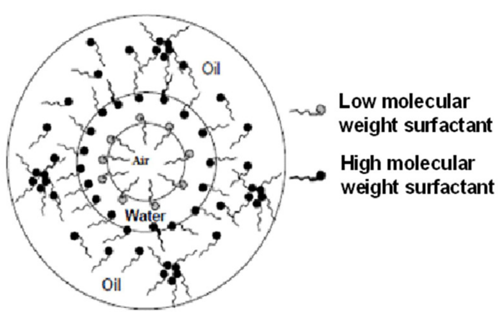

Figure 1. *Multiemulsion oil/water/air (Marcano et al., 2009)*

Turner et al. (1999) present a study on a three-phase system which they called "foam emulsion." In this case the continuous phase is water in paraffinic oil and the dispersed phase is gas. They found that the decay constant parameter of the "foam emulsion" is an intrinsic parameter of the system. They also suggested that gas bubbles are stabilized due to the rearrangement of water droplets dispersed in oil (Figure 2), surrounding the interface and increasing the superficial viscosity and elasticity associated to smaller droplet sizes in the emulsion.

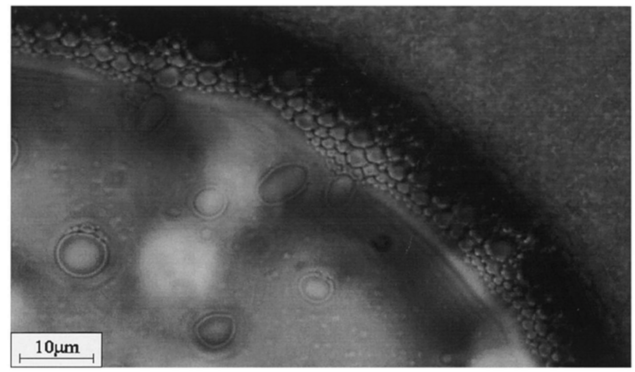

Figure 2. *Microphotograph of the emulsion-gas interphase (Turner et al., 1999)*

Regarding the "foamy oil", it can be present in heavy crude oils, whether there is presence of asphaltenes or not. The studies of Adil and Maini (2005), suggest that asphaltenes promote crude foamability. Cassani et al. (1992) studied Venezuelan heavy crude oils and obtained similar results to those of Claridge and Prats (1995). They proposed that foam stability in these crude oils is related to the adsorption of asphaltenes on the gas/oil interface, which prevents the bubbles coalescence process. Zaki et al. (2002) demonstrated that an increment in the oil viscosity and asphaltene content in non-aqueous foams increased the foamability and foam stability. In contrast, Tang and Firozabadi (1999) and Sheng et al. (1997) did not observe any difference between the foam produced with oil and silicone with similar viscosities.

Bauget et al. (2001) and Delgado et al. (2008) evaluated the effect of asphaltenes, resins and oil viscosity in the foamability of heavy oils, finding that when the viscosity is very low the film is brittle and breaks easily, if not, for high oil viscosities, the film becomes very rigid and makes difficult to form foams.

Belandria (2001) studied the effect of solids in non-aqueous foam with mineral oil viscosity up to 0.05 Pa.s. Above this value it was not possible to form foam under the studied conditions. Belandria (2001) reported that solids produced an increase in both foamability and foam stability between 50 and 100%, when the liquid viscosity was high, whereas for oil viscosities less than 0.009 Pa.s the stability of the foam was reduced with the addition of solids.

Foamy oil at reservoir conditions exhibits a behavior typical of a non-Newtonian fluid, with lower viscosities than the oil and less resistance to flow. Foam is essentially an unstable thermodynamic system where the interactions are extremely complex and depends mainly on the following factors: size, shape and amount of gas bubbles, thickness, shape and intensity of foamy fluid films, and properties such as surface tension, viscosity and elasticity of the foam solution (Xijing (1997), Yanping et al. (2002), Jing et al. (2010)).

EXPERIMENTAL SETUP AND PROCEDURE

The experimental facilities are composed by two horizontal flow loops with different diameters (0.0243 m and 0.0508 m). The sections in the flow loops are (Figure 3):

- An injection section with three parallel pumps to handle the liquid phase, with liquid flow rates ranging from 2.83m3/h to 28.27m3/h. The liquid flow rate is measured with Coriolis flow meters. In this study, the liquid phase was water in oil emulsion. The gas phase (air) is compressed and metered through an orifice plate, for "low" gas flow rates (between 6 and 118 sm3/h) and through a vortex meter for "high" gas flow rates (between 110 and 1400 sm3/h).

- A mixing section, in which the oil-water emulsion is mixed with air to form the foam, consists of 12 elements of static mixers type SMX, provided by Sulzer.

- A flow development section.

- A test section, instrumented with pressure gradient sensors, temperature sensors, pressure sensors, quick closing valves and capacitive sensors to capture the liquid holdup.

- A visualization section.

- A sampling section, to collect samples for the foamability foam stability studies in the graduated cylinders.

- A separation section, where a horizontal pipe delivers the mixture to a tank to break the foam and recover the emulsion.

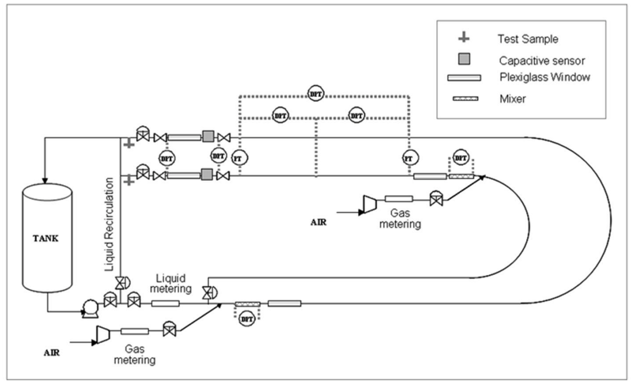

Figure 3. *Experimental test loop diagram*

The length diameter ratios for the different sections are as indicated in Table 1. Around 56 experimental points were carried in the 0.0243 and 0.0508 m pipe diameters.

Table 1. Flow loops lengths

Section\ Diameter flow loop	0.0243 m	0.0508 m
Mixing	40D	20D
Flow development	41D	827D
Test	514D	246D
Visualization	160D	80D
Sampling	160D	80D
Total	915D	1253D

The operational conditions used in this study are presented in Table 2.

Table 2. Operational conditions

Parameter	Min.	Max.
Gas Flow Rate (sm^3/h)	3	133
Liquid Flow Rate (m^3/h)	0.08	7.82
Superficial Gas Velocity (m/s)	0.92	17.56
Superficial Liquid Velocity (m/s)	0.04	1.07
Temperature at Test Section (°C)	18.9	25.7
Pressure at Test Section (kPa)	110	420

Before starting the experiments, the tank was filled up with mineral oil, and was carefully mixed with 8.5 wt.% of water and a 1.5 wt.% of a surfactant. This surfactant is a fatty acid mixture of C16-C18 and its salts generated by the reaction with the Monoethanolamine (MEA); this simulates the natural surfactants present in most of the Venezuelans crude oils (Marcano et al. 2009). After preparing the liquid phase, it was recirculated during 30 min at a fixed flow rate in order to obtain water in oil emulsion. Once the emulsion was formed, it was mixed with air until meta-stable foam was produced. Table 3 presents the properties of the fluids used. For each experimental point the hydrodynamic parameters were kept constant with time, namely: gas and liquid flow rates, pressures and temperature of the system.

Table 3. Fluids Properties

Fluid\Properties	Density at 20°C (Kg/m³)	Viscosity at 20°C (Pa.s)
Gas	1.73	0.00002
Mineral Oil	858	0.43
Water	993	0.001
W/O Emulsion	900	0.56

The gas and liquid flow rates were selected taking into account the field operating on conditions, with GOR between 10 and 1000 SCF/STB and superficial liquid Reynolds number between 5 and 300.

Once the dynamic test conditions were achieved and one experimental point was obtained, the foam was separated by gravitational separation in the tank for 24 hours. The emulsion viscosity was determined using a viscometer of concentric cylinders type HAAKE RC-20, while density and mass flow rate were quantified using a Coriolis flow meter.

Foamability and foam stability were studied in two stages, one of them consisting of taking samples of each experimental point in 3 graduated cylinders, and the other one consisting of trapping a volume of the fluid in the pipe using quick closing valves, repeating each point three times. Then, with the relation between the maximum foam height and the liquid height after total foam breakup, it was possible to determine the foamability. The stability of each system was determined using the half-life time of the foam, which corresponds to the time at which the column height is half the original foam height.

EXPERIMENTAL RESULTS

During the experiments, it was observed that foam and a separate gas phase were flowing simultaneously in the pipe, forming different flow patterns similar to the case of gas-liquid systems flowing in horizontal pipes. Foam samples were taken under dynamic conditions and foamability and foam stability were studied.

Flow patterns

Three different flow patterns were obtained, namely annular flow, slug flow and stratified wavy flow, depending on the gas-liquid ratio used in the test. The denser phase was formed by "foamy emulsion" and the lighter phase was the air. Figure 4 shows pictures of the flow patterns obtained in this study and Figure 5 the corresponding pressure response in pipeline. It is possible to identify in the plots of pressure signal against time the significant instability effect in the slug flow due to the intermittency of this flow pattern, and a lesser instability in the pressure response for a foamy segregated flow pattern, as the gas phase and the foamy emulsion phase are separated in the case of stratified flow and annular flow.

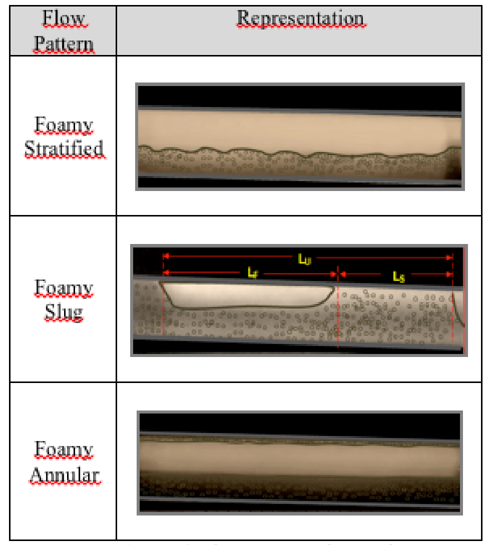

Figure 4. *Flow Pattern observed*

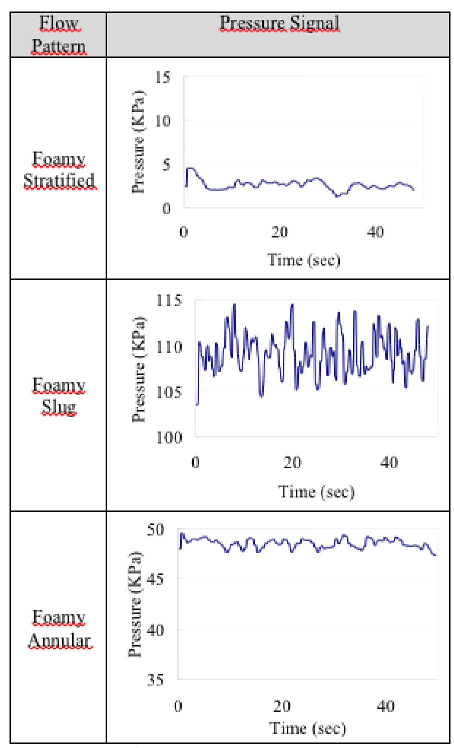

Figure 5. *Pressure response*

Similar results were presented by Bogdanovic et al. (2009) who classified the foam flow through the pipeline as a "high quality" regime for the flow characterized as unstable with oscillating pressure response, which corresponds to foamy slug flow pattern, and a "low quality" regime characterized by a stabilized pressure response for the so called uniform flow and homogeneous foam. However, in this study the non-oscillating pressure corresponds to the segregated flow pattern.

Characteristics of the foam emulsion

In order to represent the characteristics of the Foamy Oil, a highly viscous mineral oil with a viscosity of 0.440 Pa.s at the operational conditions was used in this study. The liquid mixture contains a water cut of 8.5 wt.%, 1.5 wt.% of surfactant and 90 wt.% of mineral oil, forming an emulsion with a viscosity of 0.560 Pa.s at the operational conditions. The dispersion morphology was analyzed using optical microscopy. Figure 6 and Figure 7 present the water in oil emulsion and droplet size distribution with the majority of droplet size between 2 y 8 μm, the emulsion droplet size distribution is unimodal, following a log-normal distribution as occurs in most emulsion droplet size distributions (Peña and Hirasaki (2006) and Opedal et al. (2009)).

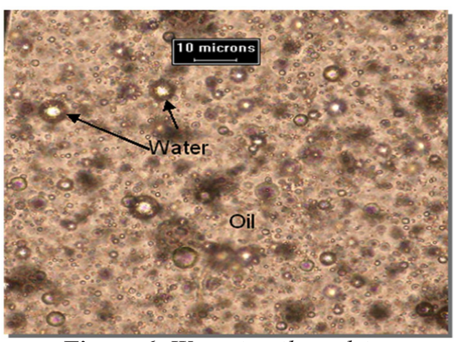

Figure 6. *Water in oil emulsion*

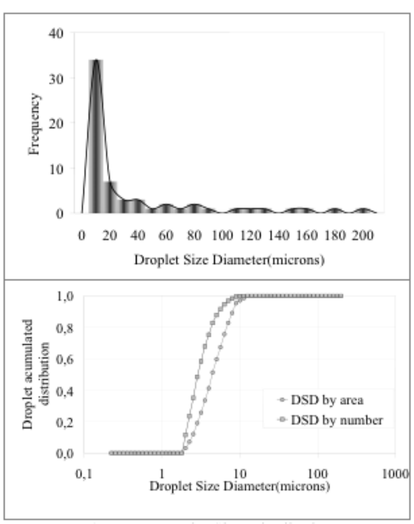

Figure 7. *Droplet Size Distribution*

The foamability and foam stability studies of the system were conducted in two different ways: the first consisted of taking samples of the mixture in graduated cylinders (Figure 8) and the second one was closing the quick valves to acquire a sample in the horizontal pipe (Figure 9). These figures show the foam evolution with time. The foam life and the behavior of the different stages of the foam: drainage, coarsening and collapse were similar in the pipeline and in the graduated cylinders in which is possible to observe that the initial drainage stage is very short, it often occurs in a few minutes, which is negligible compared to the decay time scale. The coarsening process presented in Figures 8 b and 9b takes place when the bubbles morphology changes from spherical to polyhedral shape in which bubbles are separated by flat liquid films due to the liquid loss in the foam. Then in Figures 8d and 9d the coarsening effect is no longer present, only the collapse effect was visualized.

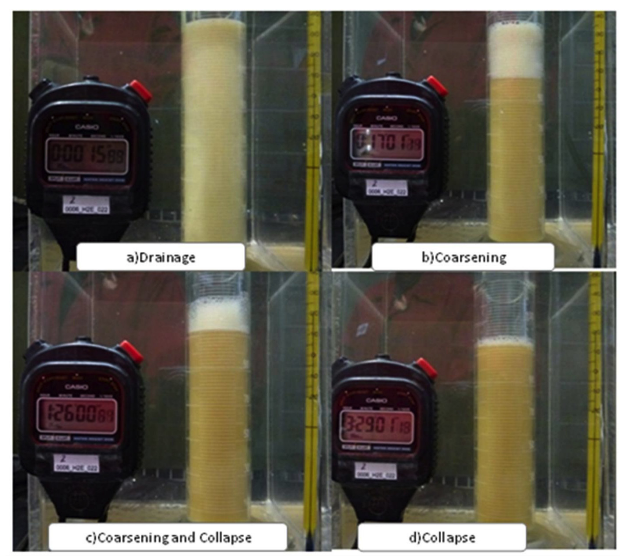

Figure 8. *Foam stages in a graduate cylinders for vsg= 3.53 m/s and vsl= 0.23 m/s*

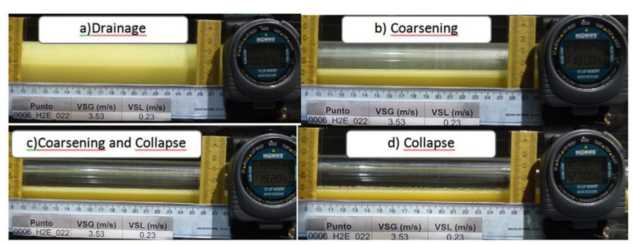

Figure 9. *. Foam stages in the pipeline for vsg= 3.53 m/s and vsl= 0.23 m/s*

In these experiments, the drainage stage took less than ten minutes (Figure 10). It was possible to observe how in the first ten seconds after taking the sample the entire graduated cylinder volume was occupied by foam with bubbles of small diameter (less than 1 mm). The size of the bubbles increases as coalescence progresses, 15 minutes later the shape of the bubbles in the foam were mostly spherical, covered by a liquid film, with bubble size in the order of several millimeters and it was possible to differentiate two zones: one with foam and the other with water in oil emulsion free of bubbles.

Figure 10 demonstrates the existence of foam coalescence/drainage mechanisms. This can be clearly seen with the drainage curve. The first mechanism is dominated by gravitational drainage, which occurs in the first ten minutes. This mechanism is characterized by the highest drainage velocity, as exhibited by the steep slope of the curve for this period. The second mechanism is dominated by capillary suction, occurring after the first 40 minutes. This mechanism results in a very slow drainage velocity, as exhibited by the near flat drainage curve for this region. There is an intermediate period of time between 10 minutes (600 sec) and 40 minutes (2400 sec), when both mechanisms are present. The foam formed in this study took around four hours to fully collapse.

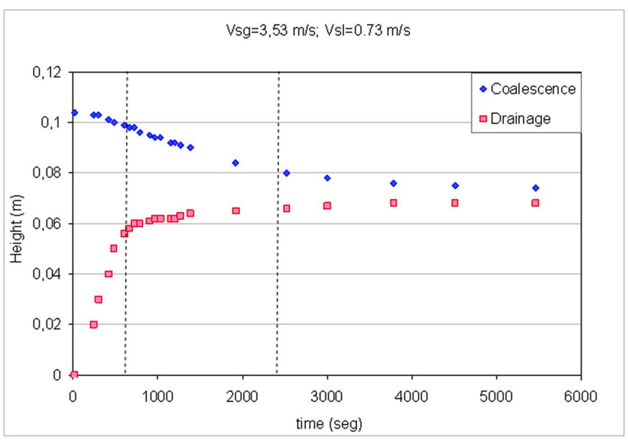

Figure 10. *Foam stages in the pipeline for vsg= 3.53 m/s and vsl= 0.73 m/s*

In this study, the same assumptions as Iglesias et al.(1995) and Belandria (2001) were made, in which the foamability of the system is related to the foam height in the graduated cylinder and the foam stability is related to the half-life time. Foamability is represented through the non-dimensional foam height, that is, the ratio of the final liquid height in which no-foam is present in the graduated cylinder to the maximum foam height. Figure 11 shows how the foamability of both pipelines of 0.0508 m and 0.0243 m system studied increases when gas and liquid flow rate increases. This effect was expected since higher flow rates translate into an increased mixing energy in the static mixers used to produce the foam. Each experimental point represented in Figure 11 corresponds to an average between three to six samples taken during the experiments with a root mean square percent error of 8% for the 0.0508-m pipe data and 6% for the 0.0243-m pipe experimental data.

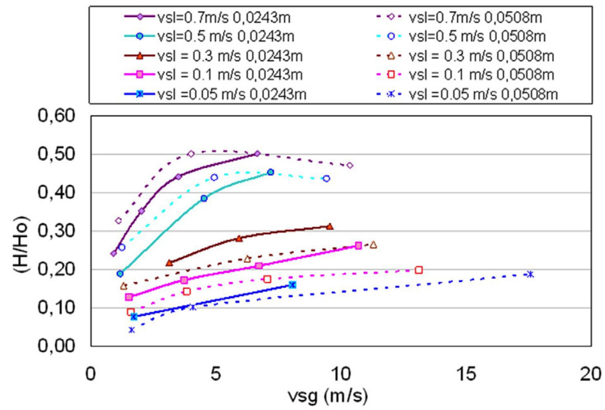

Figure 11. *Foamability versus gas-liquid superficial velocities*

Foam stability is quantified using the half-life time of the foam, Figure 12 shows how the foam stability tends to decrease when the liquid flow rate increases and the gas flow rate decreases. Based on visual observations it was possible to identify three differentiated flow patterns and their transition zones between the flow patterns characterized. These zones are identified in Figure 12: one located to the leftmost area of the plot, corresponding to the flow pattern transition zone in which there is no clear indication of which flow pattern was present in the horizontal pipe. And another zone where the flow pattern corresponding to each experimental point can be clearly identified, being whether foamy slug or foamy annular flow. For the transitional flow pattern zone the reduction of the half-life time of the foam is faster than for the other zone.

Each experimental point presented in Figure 12 corresponds to an average between three to six samples taken during the experiment with a root mean square percent error of 10% for the 0.0508-m pipe data and 12% for the 0.0243-m pipe experimental data.

Similar results were obtained by Salager (1999), when the disperse phase (bubbles) fraction increases in the foam, it produces an increment in the bubbles interactions which is translated into an increment in the collapse velocity and hence there is less foam stability.

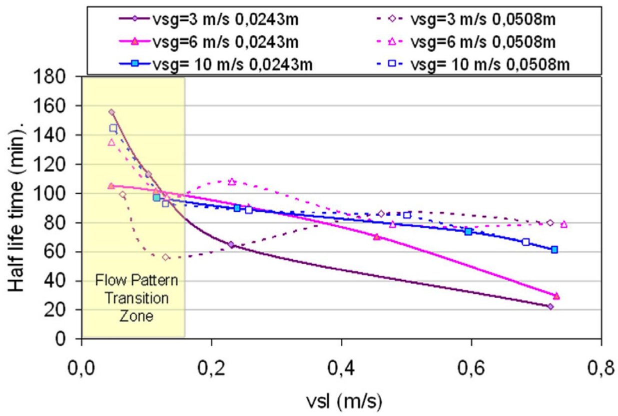

Figure 12. *Stability of the foam against gas and liquid superficial velocities*

CONCLUDING REMARKS

The behavior of a "foam emulsion" was experimentally studied at surface operational conditions in a horizontal flow loop of 0.0243-m and 0.0508-m-ID, using water in oil emulsion with high viscosity of 0.560 Pa.s at the operational conditions, 8.5 wt.% of water and 1.5 wt.% surfactant.

The most relevant results of the experimental study were:

- For the operational conditions, different flow patterns were identified in the pipeline, similar to the two-phase flow systems in horizontal pipes. These flow patterns were foamy stratified flow, foamy slug flow, and foamy annular flow, in which the denser phase was formed by the foamy emulsion and the lighter phase was air.
- The pressure response in the system was unstable in the intermittent flow patterns and relatively stable for the segregated flow patterns. This differentiated trend on the pressure response could be used in the future to identify the dominant flow pattern in a particular pipeline section. Application of this signal behavior at an industrial scale could help enhance the performance of online, real time monitoring systems, and validate multiphase flow simulators prediction capability under producing scenarios with foamy oils like the Orinoco Belt case.
- The foamability of the system increases with the increment of the gas and liquid flow rates due mostly to the increase in the mixing energy.
- The stability of the foam tends to decrease when the internal phase (bubbles) increases, due to a greater bubbles coalescence rate.

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