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A Laboratory Investigation of the Factors Controlling the Filtration Loss When Drilling With Colloidal Gas Aphron (CGA) Fluids

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Abstract

The colloidal gas aphron (CGA) drilling fluids are designed to minimize formation damage by blocking pores of the rock with microbubbles and reducing the filtration loss.

In order to gain a better understanding of the factors controlling the pore blocking mechanisms of microbubbles, a set of core flooding experiments were conducted by using various CGA drilling fluid formulations. The differential pressure drop along the sand-pack was measured.

Effects of CGA fluid composition, flow rates, type of reservoir saturating fluids, permeability and wettability on the resistance to CGA drilling fluid flow through porous media (i.e., pressure drop due to CGA fluid flow) have been investigated.

An increasing resistance to flow of CGA drilling fluids through porous media was observed as more CGA fluid was injected. Results confirmed that CGA microbubble build-up across the pore structure could establish an effective seal for controlling filtration loss.

Introduction

Like regular foams, Colloidal Gas Aphrons (CGA) are typically composed of a gaseous core but unlike foams, CGA's have a thin aqueous protective shell. CGA's are composed of an inner shell as well as an outer shell. Figure 1 illustrates the structure of the aphron on a molecular level. The two shells are separated by a viscous water phase. The inner shell consists of surfactant molecules that are hydrophobic inwards. This layer supports and separates the air core from the viscous layer. The outer shell which also supports the viscous layer is hydrophobic outwards. Since this bubble is in contact with the bulk water it is only natural to believe that there is another layer in which the surfactant molecules are hydrophobic inwards. This indicates that there is a region in between the aphron outer shell and the bulk phase layer where a hydrophobic globule will be comfortable and adhere to the gas aphron[1].

CGA flow and blockage in porous media has not been studied extensively. Rather extensive literature , however, can be found on the on the flow of conventional foams in porous media.[2-7] Although CGA's and foams show structural differences, some of the results from foam flow in porous media studies can be helpful to understand the CGA's behavior. Therefore, a brief discussion of the literature on the use foam in porous media is presented here. Much of the conventional foam research has focused on foam applications for enhancing oil recovery. As well, there is a large focus on the creation of foams in the porous media itself[8-9]. Bernard and Holm[10] studied the effect of foam on the reduction of gas permeability while Bernard et al.[11] studied the effect of foam of the reduction of water permeability. They found that foam effectively plugged the gas flow in the reservoir. Albrecht and Marsden[3] studied foam blocking and found that with an increase in surfactant concentration, the blocking effect was greater. Manlowe and Radke[12] investigated the effect of oil on foam stability in porous media using an etched glass model. They found that the lack of stability of the foam when in contact with oil is determined by the strength of the film in between the bubble and the oil.

Foam gel combinations have also been studied to enhance blocking ability[13-16]. Wassmuth et al.[13] investigated the blocking ability of polymer enhanced foam and foam gels. They found that with an increase in the polymer viscosity, the blocking ability increased. Dalland and Hanssen[17] also compared foams, polymer enhanced foams and foam gels. They found the polymer enhanced foams increases the gas blocking ability but that at high concentrations of polymer, the blocking efficiency can be reduced.

Mast[18] used an etched glass model to study the flow of foam through porous media. It was discovered that the foam blocked some of the pore throats and it was concluded that this was due to Jamin Action. . The Jamin Effect or as it is sometimes referred the Jamin Action was initially described by Jamin[19] in the late 19th century as the resistance caused by the boundary conditions of gas and liquid bubbles in a confined capillary space[20]. It describes the retardation of liquid flow in capillaries due to the presence of bubbles[21]. Owete and Bringham[22] also concluded that Jamin Action was responsible for the blockage of pore throats. The average bubble size was as large as or larger than the pore size. Blockage was temporary and it occurred in the smaller flow channels only.

A study on the flow of CGA's in porous media has been presented by Growcock et al.[23]. They included the visualization of aphrons in a microcell but did not provide any visualization of plugging or a quantitative pressure range for the experiment. Bjorndalen et al.[24-25] provide micromodel studies of CGA flow. They concluded that there was successful blockage of the micromodel by the CGA fluid as the pressure rose for the extent of the test. CGA mud system was investigated by Growcock[26]. He found that the aphrons in the mud system inhibit the movement of liquid and that the CGA along with particulates in the mud system create bridges in the porous media. This combined with the radial flow of the mud in the formation which decreases shear rate, increases the viscosity of the fluid and causes a drastic decrease in the velocity of the mud system. Belkin et al[27] showed that the formation damage of a CGA drilling mud is low and that 80% or more of the original permeability is returned after CGA injection.

Basic mechanisms of resistance to flow include pore plugging due to particle invasion. The particles, which can be in the form of solids, liquids or gases alter the permeability of the formation. The mobility of particles in the formation is strongly dependant on surface and interfacial forces. Sarkar and Sharma[28] found that core wettability, residual oil saturation and oil and water fractional flow all play a role in determining particle invasion.

The purpose of this study is to understand the extent of resistance to flow through porous media caused by CGA drilling fluid. Pressure drop through porous media is used as key parameter for assessing the amount of blockage the CGA fluid will accomplish. Higher pressure drop across the porous media indicates more effective blockage of fluid invasion. Pressure drop through porous media was measured for different flow rates, formulations of CGA fluid, sandpack saturation fluids, permeabilities and wettability.

Experimental Program

Pressure Vessel Design

A diagram of the sand pack pressure vessel utilized in this study is given in Figure 2. The aluminum pressure vessel is equipped with two production wells at the wall of the cell and one injection well at the center of the cell. The injection tube sits inside a larger tube which can be utilized either for injection or as a fluid bypass. The two production tubes and the larger injection tube are partially slotted and screened. The cell was designed to roughly simulate radial flow by equipping the inner diameter of the aluminum pressure vessel with a screen. This screen was utilized to encourage radial flow to the outer edge of the pressure vessel and thus to the producer tubes. The bottom end cap of the cell is equipped with a sandpacking port that is used to pack the vessel with sand.

Saturation Fluids

Water, brine, mineral oil and crude oil have been used for saturating the porous media. The properties of the reservoir saturation fluids can be found in Table 1. An artifical brine waas prepared in the laboratory using a brine composition of a typical Lloydminster reservoir.

CGA Formulation

A Xanthan Gum (XG) – water mixture was used as the base drilling fluid. The CGA fluid was prepared by using a method similar to the one described by Bjorndalen and Kuru[29].. The XG base fluid was prepared at concentrations of 2 lb/bbl. Sodium dodecyl benzene sulfonate (DDBS), an anionic surfactant, was added to the base fluid for aphronization at concentrations of 2 lb/bbl. The specific concentrations of polymer and surfactant used in this study were selected to provide stable CGAs for the duration of the test. Stability data for the aphronized fluid was previously presented by Bjorndalen and Kuru[30].

Sandpacking Procedure

The pressure vessel was packed with sand via a sandpacking injection port at the bottom of the pressure vessel. Either F110 (0.210 to 0.053 mm dia.) sand or 40 to 70 (0.47 to 0.262 mm dia.) mesh sand was used. The properties of the sandpack for each exeperiment can be found in Table 2. The pressure vessel was continuously mechanically agitated while the sand was poured into the vessel at intervals. In between the pouring intervals the pressure vessel was also manually vibrated.

Wettability Alteration Procedure

To investigate the effect of wettability, the normally water-wet sand was chemically altered to become oil- wet. The alteration of the sand from hydrophilic to hyrdrophobic is achieved through methylation[31]. Methylation of the F110 sand was conducted by submersing the sand in 5 vol% trimethylchloronsilane and 95% toluene. The sand was placed in a fumehood and the toluene was evaporated leaving behind the altered sand.

Saturation Fluid Injection

Table 3 summarizes the saturation fluids used for each experiment. Saturation was achieved by injecting more than 1.5 PV (pore volumes) into the sandpack and by cycles of pressure build-up and release. After water or brine injection, the pack was then injected with oil (Experiments 6 -7). In the oil-wet sand pack case (Experiment 9), the pack was saturated with mineral oil alone.

CGA Fluid Injection

A schematic of the experimental set-up is given in Figure 3. The aphronized fluid is pumped into the sandpack vessel from the accumulator. Initially, the valves at the producer tubes are closed and the bypass valve is opened. This was continued until CGA fluid was present at the outlet of the bypass valve. The bypass valve was then closed and the production valves were opened initiating the test. Pressure was measured at the inlet and outlet of the sandpack using a differential pressure transmitter. The outlet pressure was maintained at atmospheric conditions for all runs. The aphronized fluid was injected at a fixed flow rate into the sandpack until a close to maximum pressure was obtained. Once this point was reached, the foam injection was stopped and satuation fluid was re-injected at the same rate as the foam until equilibrium was reached. Pressure values were recorded using a data acquisition system at intervals of 1 minute.

Figure 4 gives an example of a typical experimental result. All results are reported in pressure drop per meter of distance traveled through porous media. The graph is separated into two sections: CGA Injection and Saturation Fluid Re-Injection. During the CGA Injection, CGA fluid was directly injected into the sandpack at a given fixed flow rate. The pressure rose in the sandpack as the CGA fluid invades and blocks the pores of the pack. From the graph, at approximately the 2 and 4 PV intervals, there was decreases in pressure. At these intervals, the sandpack was shut-in and the fluid in the CGA accumulator was replenished. As the experiment progressed, the amount of fluid that could be injected at each accumulator interval decreased. This is due to the fact that as the pressure of the system increases (i.e., sandpack, accumulators, injection lines and pump), the fluid (composed of gas and liquid) becomes more compressed in order to reach that pressure. As well with each shut-in, the flow paths that were once open in the sandpack might be closed and vice versa, due to the fluid equilibrating itself inside of the pack. Therefore, it was very difficult to get an absolute value for maximum pressure and this is the reason why an approximate maximum pressure was reported.

Eventually, the pressure will come to an approximate maximum pressure (after around 6 pore volumes (PV) of CGA injection, Figure 4), where more injection of CGA fluid will not increase the pressure in the pack appreciably. This is an indication of the maximum pressure drop that can be achieved due to the flow of CGA fluid through of the porous media. Higher pressure drop shows that there is more resistance to flow.. The section of the graph labeled as saturation fluid re-injection indicates the point where the injection fluid was switched from CGA fluid to the original saturation fluid.

Saturation Fluid Re-Injection

Reservoir fluid was re-injected into the sandpack after the maximum pressure with the CGA fluid injection was reached. This was done to determine how easily the CGA fluid could be removed or destroyed from the system and to also get an indication of the return permeability. The fluid was injected at the same rate as the foam until a constant minimum pressure was reached. Pressure values were recorded using a data acquisition system at intervals of 1 minute. In Figure 4, the section of the graph labeled as saturation fluid re-injection indicates the point when the injection fluid was switched from CGA fluid to the original saturation fluid.

Results and Discussion

Tests were conducted at different flow rates, CGA formulation, saturation fluids, permeability and wettability. Table 4 lists the experiments conducted and the parameters used for those experiments.

Effect of Flow Rate

Figure 5 indicates the effect of flow rate on the CGA injection pressure. When the flow rate was increased from 3 cc/min to 4 cc/min, the maximum injection pressure per meter increased from approximately 9300 kPa/m to 10200 kPa/m.

Effect of CGA Fluid Composition

Figure 6 shows the results from the experiments with three different CGA formulations, one without any polymer (W-P0-S2-R3-k3), one without any surfactant (W-P2-S0-R3-k3) and one with both polymer and surfactant (W-P2-S2-R3-k3). The highest pressure drop was observed when both polymer and surfactant were used (W-P2-S2-R3-k3) with an approximate maximum of around 9600 kPa/m compared to 2500 kPa/m and 420 kPa/m for the experiment without surfactant (W-P2-S0-R3-k3) and for the experiment without polymer (W-P0-S2-R3-k3) respectively. Without any polymer (W-P0-S2-R3-k3), the CGA is not very stable and cannot last over long a period of time. This is evident from the rise and fall of pressure between 0 and 2 PV of injection. When comparing the experiment with both polymer and surfactant (W-P2-S2-R3-k3) to the experiment without surfactant (W-P2-S0-R3-k3), we can see the effect CGAs have on the pressure drop across porous media. No CGAs were generated in when there was no surfactant in the formulation. It shows that without CGAs the pressure rise was much less.

Effect of Saturation Fluid Type

Figure 7 compares the effect of water and brine as saturation fluids on the pressure drop due to flow of CGA fluid through the sand pack. The rate of injection pressure increase (i.e., pressure drop across the sand pack) was very similar for both cases. When brine is used as a saturation fluid, there is a pressure rise due to a flow rate increase from 3 to 4 cc/min shortly after 5 PV of injection. The results indicate that there is very little change in the pressure drop due to CGA fluid flow through a sandpack saturated with brine when compared to CGA fluid flow throughsandpack saturated with water.

The results from the experiments comparing the effect of mineral oil and water as saturation fluids are shown in Figure 8. Although the rate of injection pressure increase was similar, the maximum pressure required for the injection of CGA fluid into porous media was different for both cases. A higher pressure was required to inject CGA fluid in the sandpack saturated with mineral oil. This might be due to the very high viscosity of the mineral oil compared to the other fluids that were used. Since mineral oil is more viscous than water, it requires a greater amount of pressure to displace the oil through the pores.

Figure 9 compares the effect of water to crude oil as the saturation fluid. The pressure drop due to flow of CGA fluid through sand pack saturated with crude oil was less than that of the pressure drop due to CGA fluid flow through sand pack saturated with water. After 6 PV of CGA fluid injection, the pressure drop in the sandpack was 18% less in the crude oil case than in the water case. This may be due to the instability of the CGA fluid occuring when the fluid comes in contact with crude oil.

Effect of Permeability

The effect of permeability is given in Figure 10. The sandpack with the greater permeability (42D) (B-P2-S2-R3-k42) has a slower rate of pressure drop than the experiment with the lower permeability (3D) (B-P2-S2-R3-k3/B-P2-S2-R4-k3). The maximum pressure drop for the 42 D sandpack was almost 4000 kPa/m compared to a maximum pressure drop for the 3 D sandpack of more than 9000 kPa/m (at 3 cc/min). Lower permeability sandpacks have a higher resistance to flow so the pressure drop should be greater.

Effect of Wettability

Experiments were conducted using sandpacks prepared with water-wet and oil-wet sands. The wettability of the water-wet sand was changed by treating the sand with a saline solution to make the sand oil-wet. Once the sand was treated, it was packed into the sandpack vessel and saturated with mineral oil. Figure 11 shows the difference between the original water-wet sand and the treated sand. The untreated sand (Figure 11a) disperses throughout the water whereas the treat oil-wet sand (Figure 11b) clumps together on the surface of the water showing a change in wettability.

The experimental results for the two different sands is given in Figure 12. The pressure drop in the oil-wet sand is almost 3 times less than the pressure drop in the water-wet sand. This indicates that CGA's are less effective at blocking oil-wet porous media. These results are in agreement with what other researchers found when using conventional foams which indicated that in porous media that is not water-wet foams are less likely to be stable[32]. However, at this point the effect of wettablity on CGA's is not fully understood and further investigation is required.

Conclusions

The following conclusions can be drawn from the sandpack experiments:

- Higher pressure drop through porous media was observed when flowing CGA fluids formulated by using both polymer and surfactant (as compared to the flow of fluids formulated with only polymer and only surfactant). Higher resistance to CGA fluid invasion in this case indicates that both polymer and surfactant are needed for a stable CGA fluid.
- In most cases, the maximum pressure (i.e. pressure drop through porous media) required for injection of CGA fluid through porous media saturated with brine was similar to that of the case when water, was used as saturation fluid.

- The maximum pressure required for injection of CGA fluid through porous media saturated with mineral oil was higher than that of the case when water was used as saturation fluid. This might be due to the fact that mineral oil has much higher viscosity than that of water.
- The maximum pressure required for injection of CGA fluid through porous media saturated with crude oil was lower than that of required for CGA fluid injection when water was used as saturation fluid. After injecting 6 PV of CGA fluid, the pressure drop across the sandpack is 18% less in the former case (i.e., crude oil is saturating fluid) than in the latter case (i.e., water is saturating fluid). This may be due to the instability of CGA's in the presence of crude oil.
- Lower permeable sand packs result in a greater pressure rise and greater blocking ability.
- Wettability of the porous media has significant effect on the blocking ability of CGA's. CGA's block more efficiently in water-wet situations.

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Table 1: Properties of the reservoir fluids

Fluid	Viscosity @ 22˚C (cP)	Density (g/cc)
Brine	1	1.00
Mineral Oil	80	0.87
Crude Oil	7	0.85

Table 2: Properties of the sandpack used for each experiment

Experiment #	Sand	Porosity (%)	Permeability (D)	Effective PV
B-P2-S2-R3-k3	F110 (water wet)	35.2	3.0	489.9
B-P2-S2-R4-k3	F110 (water wet)	35.2	3.0	489.9
W-P2-S2-R3-k3	F110 (water wet)	35.5	3.0	494.9
W-P2-S0-R3-k3	F110 (water wet)	35.4	3.0	493.4
W-P0-S2-R3-k3	F110 (water wet)	35.5	3.0	493.7
MO-P2-S2-R3-k3	F110 (water wet)	35.3	3.0	491.7
CO-P2-S2-R3-k3	F110 (water wet)	35.4	3.0	492.7
B-P2-S2-R3-k42	40/70 (water wet)	34.5	42.0	479.9
MO-P2-S2-R3-k3-OW	F110 (oil wet)	35.6	3.0	492.3

B – Brine
CO – Crude Oil
k - Permeability
MO – Mineral Oil
OW – Oil Wet
P – Polymer
R – Rate
S – Surfactant
W – Water

Table 3: Types of saturation fluids used for each experiment.

Experiment #	Primary Saturation Fluid	Secondary Saturation Fluid
B-P2-S2-R3-k3	Brine	-
B-P2-S2-R4-k3	Brine	-
W-P2-S2-R3-k3	Water	-
W-P2-S0-R3-k3	Water	-
W-P0-S2-R3-k3	Water	-
MO-P2-S2-R3-k3	Brine	Mineral Oil
CO-P2-S2-R3-k3	Brine	Crude Oil
B-P2-S2-R3-k42	Brine	-
MO-P2-S2-R3-k3-OW	Mineral Oil	Mineral Oil

B – Brine
CO – Crude Oil
k - Permeability
MO – Mineral Oil
OW – Oil Wet
P – Polymer
R – Rate
S – Surfactant
W – Water

Table 4: Experiments conducted in this study

Experiment #	Permeability (D)	Saturation Fluid	% Saturation	Polymer Conc. (lb/bbl)	Surfactant Conc. (lb/bbl)	Flow Rate (cc/min)
B-P2-S2-R3-k3	3.0	Brine	100	2	2	3
B-P2-S2-R4-k3	3.0	Brine	100	2	2	4
W-P2-S2-R3-k3	3.0	Water	100	2	2	3
W-P2-S0-R3-k3	3.0	Water	100	2	0	3
W-P0-S2-R3-k3	3.0	Water	100	0	2	3
MO-P2-S2-R3-k3	3.0	Mineral Oil	87	2	2	3
CO-P2-S2-R3-k3	3.0	Crude Oil	85	2	2	3
B-P2-S2-R3-k42	42.0	Brine	100	2	2	3
MO-P2-S2-R3-k3-OW	3.0	Mineral Oil	100	2	2	3

B – Brine
CO – Crude Oil
k - Permeability
MO – Mineral Oil
OW – Oil Wet
P – Polymer
R – Rate
S – Surfactant
W – Water

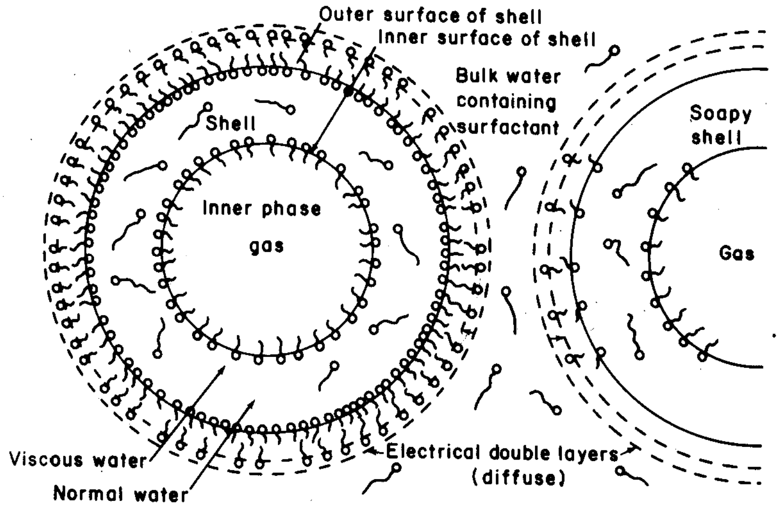

Figure 1: Structure of a CGA (Sebba, 1987)

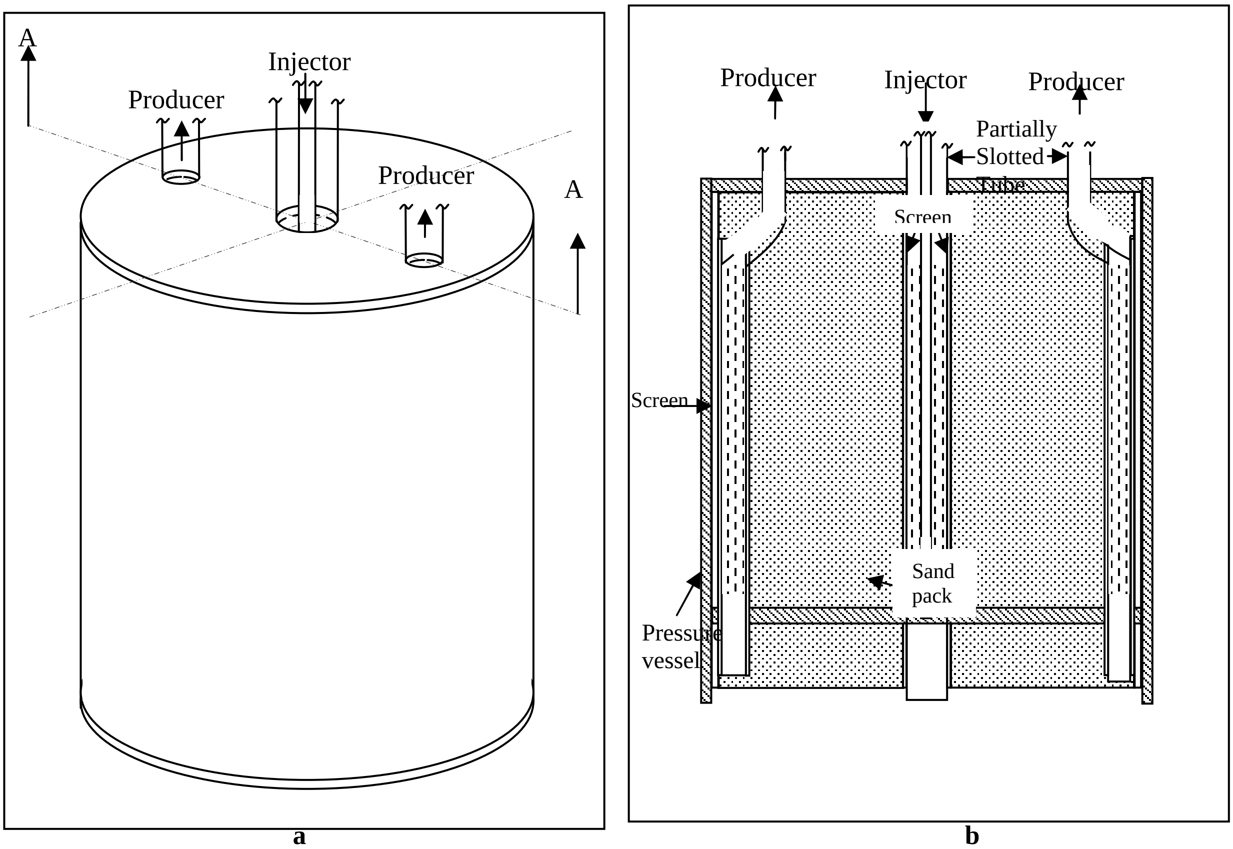

Figure 2: Schematic of the sand pack pressure vessel

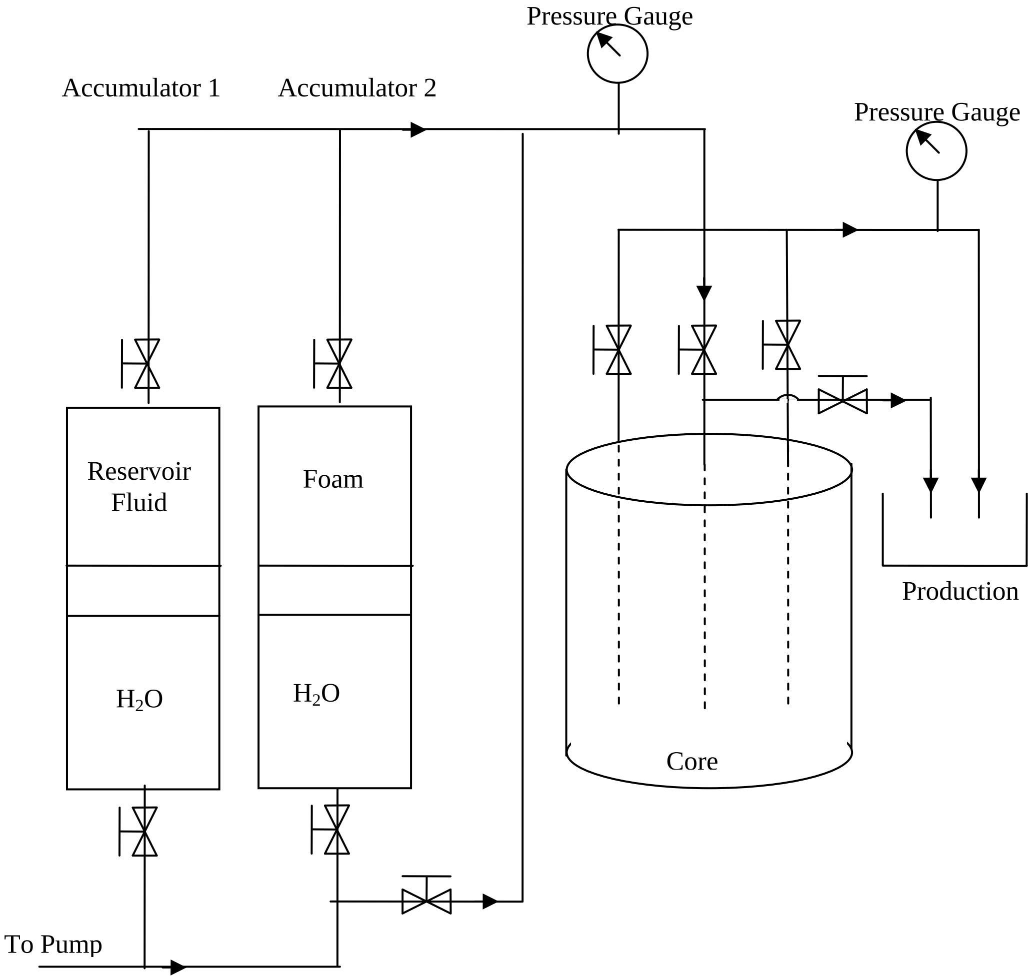

Figure 3: Schematic of the experimental set-up

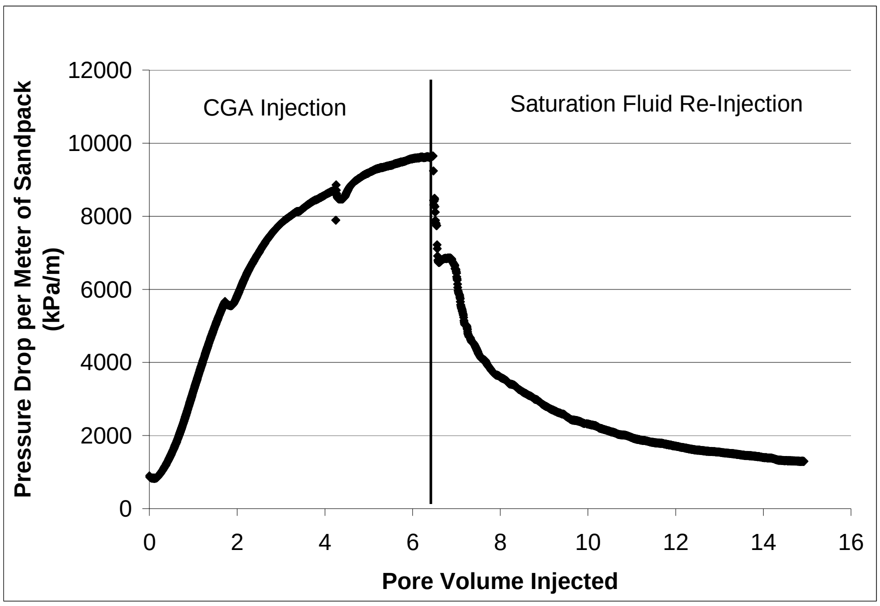

Figure 4: Data recorded in typical experimental run

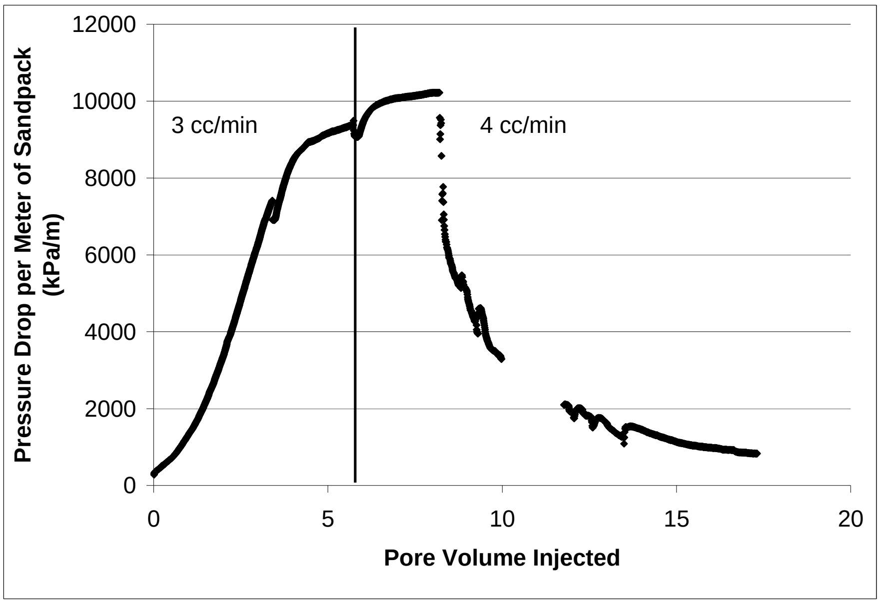

Figure 5: Effect of changing CGA fluid injection rate from 3 cc/min to 4 cc/min (B-P2-S2-R3-k3 and B-P2-S2-R4-k3) on the pressure drop.

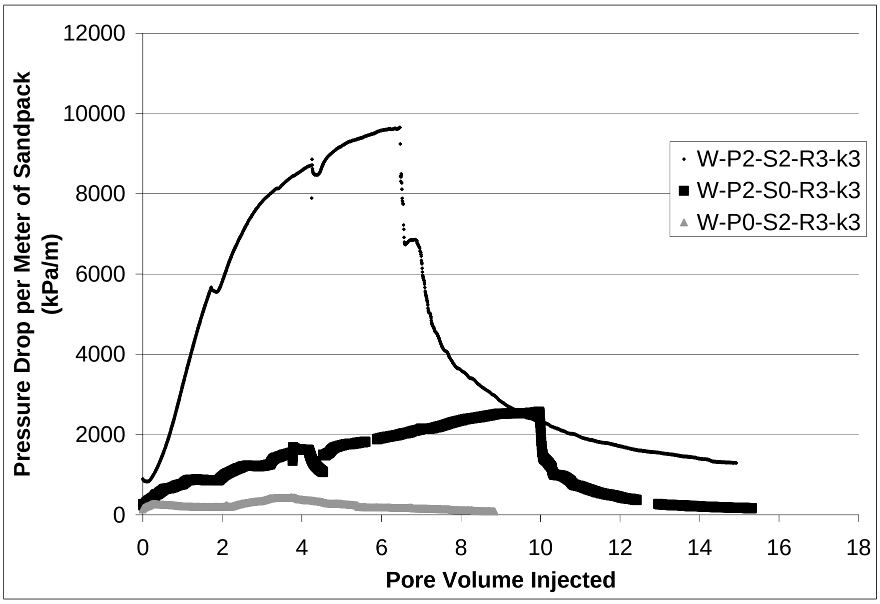

Figure 6: Effect of polymer and surfactant concentration used for CGA formulation on the pressure drop.

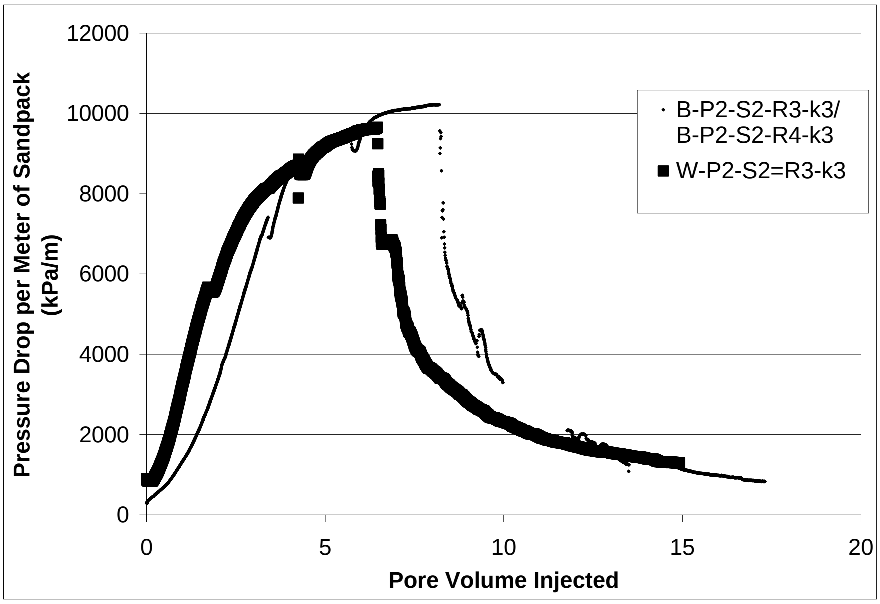

Figure 7: Effect of the saturation fluid on the pressure drop; Brine vs.Water

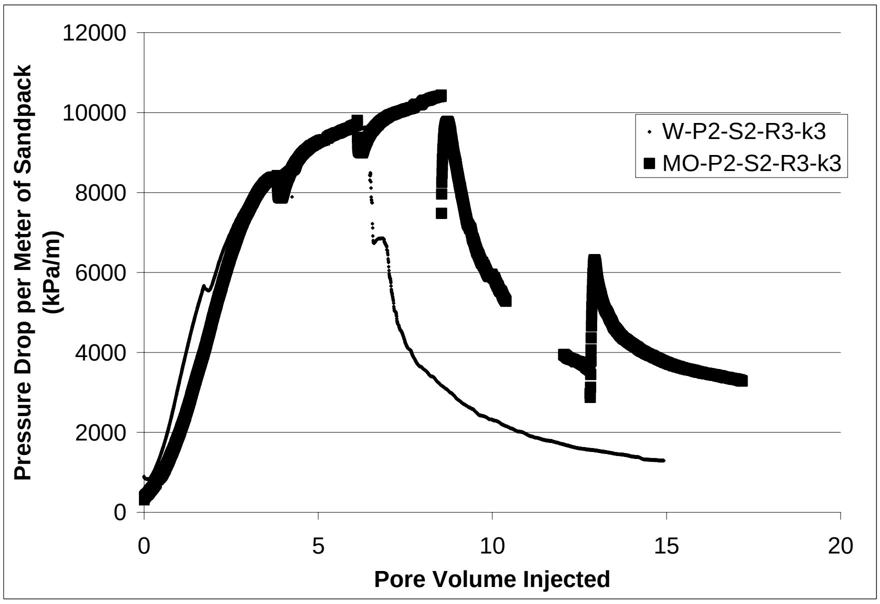

Figure 8: Effect of the saturation fluid on the pressure drop; Mineral oil vs.Water

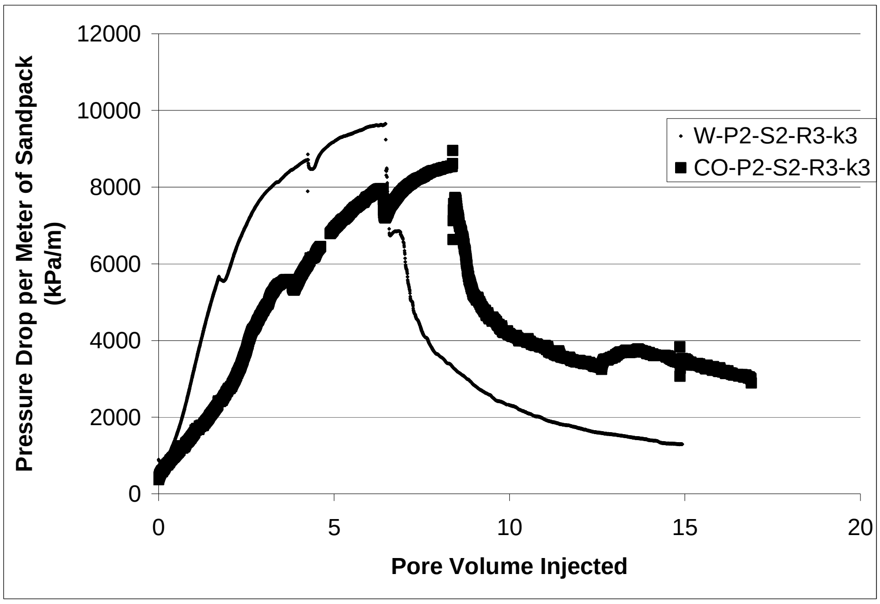

Figure 9: Effect of the saturation fluid on the pressure drop; Crude oil vs.Water

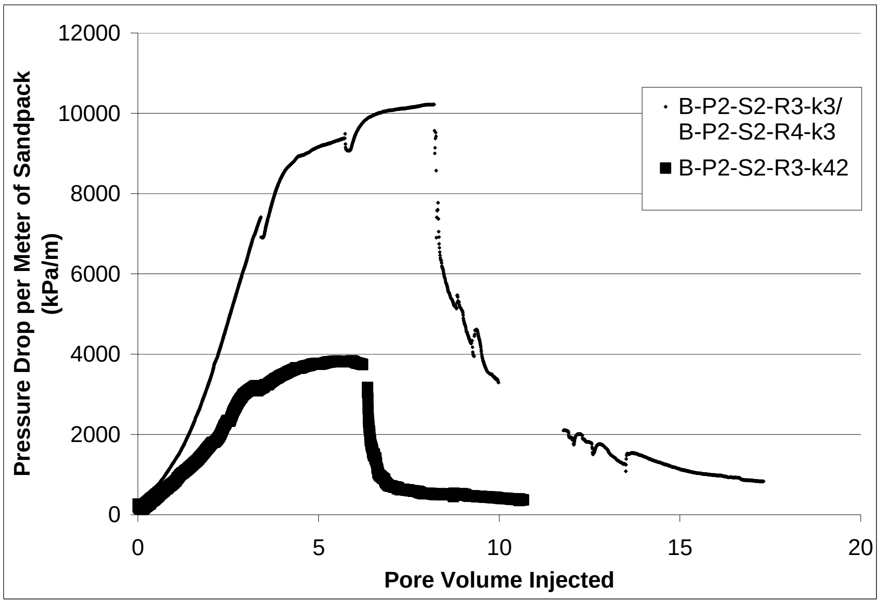

Figure 10: Effect of permeability on the pressure drop

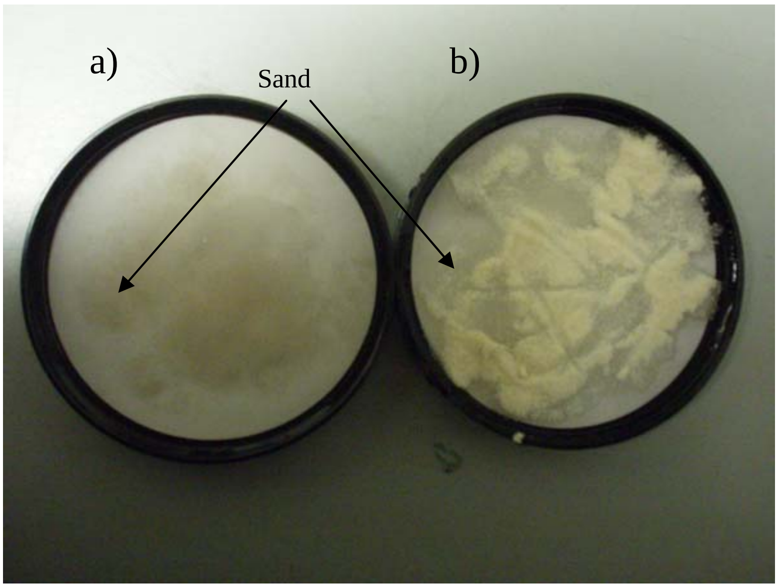

Figure 11: Comparison of oil wet and water wet sand immersed in water.

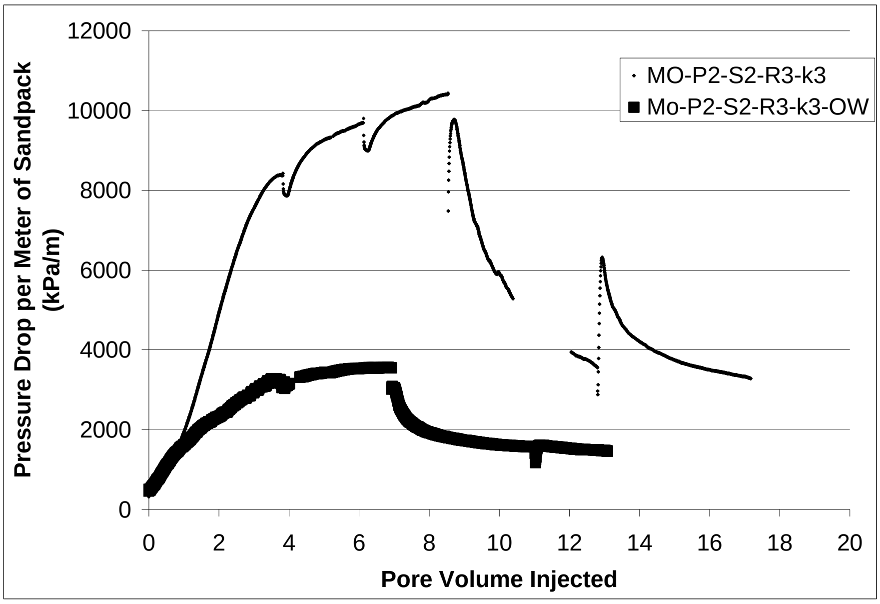

Figure 12: Effect of wettability of thethe porous media on the pressure drop.