Experimental Measurement Process of a Volume Displacement of Oil Caught in a Fractured Rock by Gravity and Using Surfactant Foam

Arnulfo Ortíz Gómez

Abstract We present a series of experiments conducted in a cell with two parallel plates made of acrylic, the foundation plate used as a base is 0.5 in. thick. Inside it 4 mm deep and 6 in. wide channel was made, the wet perimeter was covered with sand and a cementing material, after the cap was set, it was filled with oil. We measured the filling time by means of a constant column, the time it took the cell to empty from different angles, where the only acting force displacing oil was gravity. We also measured the emptying time when using foam as displacing agent on different slopes, the foam was generated by injecting air into a mixture of water, glycerin and a surfactant, them it was introduced to the cell through a latex line of 10.0 mm diameter. The results found allowed us to establish meaningful conclusions in order to understand the rheology of foams, after being used as secondary methods of oil production in fractured reservoirs.

1 Introduction

Enhanced Oil Recovery (EOR) refers to all the processes used to recover more oil from a reservoir than the one being recovered by primary methods, it mostly involves the injection of gas or liquid chemicals and/or using thermal energy. Among the former ones, the most used are: gaseous hydrocarbons, CO2, nitrogen and flue gas. Among the liquid chemicals polymers, surfactants and hydrocarbon solvents can be found. Finally, thermal processes are related to the use of steam or hot water, or the in situ generation of thermal energy by internal combustion of oil in the rock of the reservoir (Donaldson and Chilingarian 1985; Baviere and Canselier 1997; Roehl and Choquette 1985).

A. O. Gómez (✉)
División de Ciencias Básicas, Facultad de Ingeniería, UNAM, Ciudad Universitaria,
CP 04510 Coyoacán, México City, D.F., México
e-mail: arnulfo64@gmail.com

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Such interactions can, for example, lead to a decrease in interfacial retention, oil swelling and reduction in viscosity, modifying the wettability or favorable behavior of phases. The latter ones are of special interest in this work, which deals with the process of oil displacement that is trapped in a crevice, by means of reducing the phenomena listed above.

The study was done by making an acrylic rectangular cell, where the wetted perimeter was covered with sand produced in the Cantarel area. Inside the cell a series of filling and emptying experiments were performed by means of gravity and by surfactant injection. We measured the filling and emptying times from different angles, using a surfactant, saturation and volume displacement percentages at emptying times. With the information gathered, capillary pressure variation, permeability of the material and percentages of saturation graphs were prepared. It was also possible to verify the formation of fingers due to the menisci advance.

2 Injection Foam (Surfactant)

The process demanding our attention is the one related to the injection of gases and mixed fluids in a surfactant, known as foam. In secondary recovery operations when water or gas is injected into the reservoir, also immiscible displacements occur, such kind of sweeping is due to the mixture of gas, liquid and additives which allow interfacial activity; *surfactants* is the term normally used to abbreviate the compounds with activity between phases (Morrow and Mason 2001; Shah and Schechter 1977). Chemically, the surfactants are characterized by having a molecular structure containing a group that has little attraction or antipathy for the solvent, known as liofóbico group, along with another group that has strong attraction, appetite for the solvent, called liofílico group. If the solvent is water, these groups are known as hydrophobic and hydrophilic portions of the surfactant. Usually, the hydrophobic group is a linear carbon chain or branched, while the hydrophilic portion is a group with some polar character. In the case of water injection the process is similar to the one mentioned above, this is due to the physicochemical characteristics of both fluids, a surfactant that allows the interaction between the present phases is required.

Assuming for simplicity that the porous medium containing a brine (water-crude, W-O), these two phases are distributed by the hydrostatic laws of capillarity. The basic Laplace Law capillary equation relates to the pressure difference between the sides of an interface (capillary pressure, Pc) with the curvature:

$$P_c = \Delta P = P_o - P_w = 2\gamma R \tag{1}$$

Where γ is the interfacial tension, R is the average curvature of the interface. A hemispherical surface to the average curvature radius is reversed. Pair any surface, R is half the sum of the reciprocal surfaces of the principal radius of curvature (high and low).

The interfacial tension is the Gibbs Energy per unit of area, this one depends on the substances absorbed in the interface. For water to be in equilibrium with a hydrocarbon phase, this energy is just of some sets of 10 dyne (din/cm or mN/m) (Johansen and Berg 1978; Shah 1981; Larry 1989). In the presence of a surfactant this energy is generally reduced to 1.0 or 0.1 din/cm.

Contact angle. The three-phase contact, water (W), oil (O) and solid (S) is identified as the contact angle between the surfaces.

If we assume that the solid is quite flat at the point of contact, you can set a vector equation of equilibrium between the forces, called Newman balance.

$$\gamma_{SW} + \gamma_{WO}\,(cos\ \theta_W) = \gamma_{SO} \tag{2}$$

$$\cos\theta_W = (\gamma_{SO} - \gamma_{SW})/\gamma_{WO} \tag{3}$$

The magnitude of the contact angle depends on the interfacial tension between O and W (γ_{WO}) and on the free interfacial energies of the solid with the two fluids as well, in other words, it depends on the natural fluids and the surface of the solid.

The fluid which has a contact angle, $\theta < 90°$ wets the solid surface. The reservoir rocks have a polar nature (silica carbonate) and thus the clean rock can be wet with water. Despite this, in many reservoirs $\theta > 90°$ something different is observed, because the solid surface is covered by a layer of absorbed substance which gives an oily character (Baviere 1991; Salager and Antón 1999; Pillai et al. 1999; Salager and Microemulsions 1999).

3 The Experiment

In order to understand the rheology of the surfactant interacting with the water and oil an acrylic cell with three sidewalls made of stone was designed, Fig. 1a. Subsequently it was filled with high density oil, so that it could not be displaced in the absence of gravity. Then we proceeded to inject a mixture of water, surfactant and glycerin, the latter one was to prevent *minimal surfaces* from dehydrating quickly and being broken down.

The idea is to simulate what happens in a fractured rock full of oil, when the lower part is connected with the reservoir and the upper part is in contact with the atmosphere, after an injection well was drilled (Fig. 1b).

In order to improve oil recovery, we developed a chemical formula that can alter the wettability of the oil and preferably water, lowering surface tension, so that the effect of capillary breaks and the oil can be conducted by effect of gravity, and can change the cross flow between layers permeability.

The experiment was performed as follows: firstly we connected a supply valve (Qe Fig. 1) to a conducting line (latex hose inner diameter 0.8 cm), secondly, we filled the container with a volume of oil equal to the volume of the cell ensure that the flow opened two keys; the supply and the output. The filling process was always the

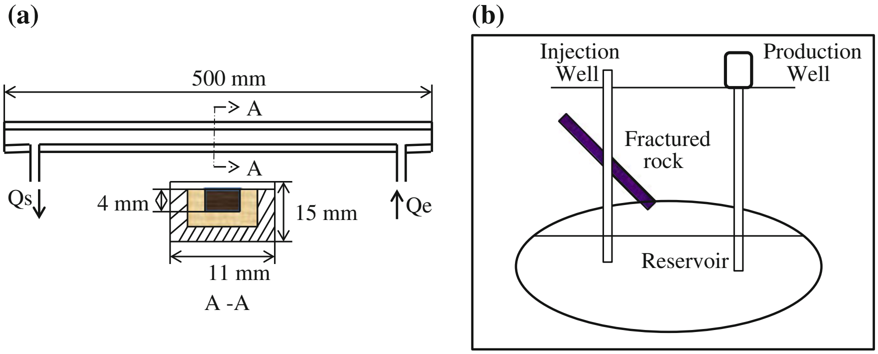


Fig. 1 **a** Experimental model; acrylic cell slot 50.0 mm by 4 m deep, the wetted perimeter is a limestone core Cantarel study. **b** Image of a fractured penetrated by an injection well

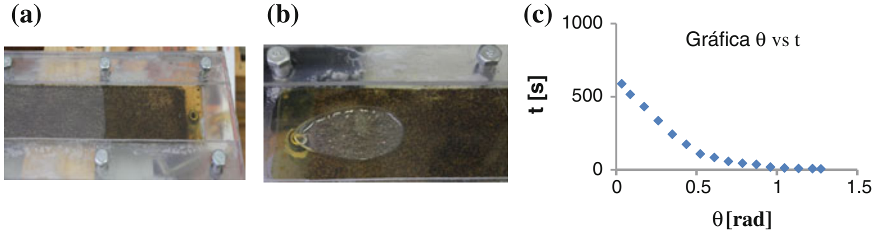
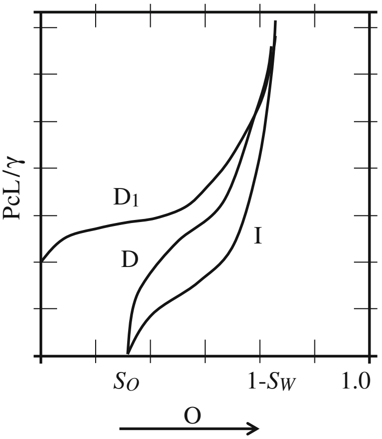


Fig. 2 **a** Advancing front during the filling process. **b** Advancing front during the casting process. **c** Graph of slope θ, versus time t, it is seen a shorter steeper emptying the cell

same, the total filling time associated with the cell was 15.0 min ($T_{LL} = 15$ min), maintaining a hydraulic head of 20.0 cm above the cell. This process is performed by simulating a source and a sink (*Qe* and *Qs* Fig. 1), since the supply valve and outlet are located at the base of the cell. Right in the source, oil gets radially into the cell but as soon as it finds walls, it advances or moves in a horizontal direction (*xi*), the face is convex, because the friction on the walls increases, the liquid is confined to four walls where the wetted perimeter of the landfill is sandy and the top cover is 4.0 mm acrylic to make it easy to view. In Fig. 2a an image of the forward advance in two different instants is shown. During this movement it was observed that the parabola formed by the advancing front is not parallel, sometimes it fills more in one side of the cell than in the other and vice versa, this is because the wall friction does not have a constant presence.

The times associated to the emptying of the cell to different slopes were measured too, now the walls stop the oil slick, emptying first in the center, so the front is concave Fig. 2b. The experiment was performed from different angles ($0° < \theta < 80°$) measuring the times for each slope, the results found are shown in the graph of Fig. 2c.

Fig. 3 Capillary pressure variation to successively injects of water and oil in a rock core, usually for a study of the perforations. In the experiment we do it in the cell



When two immiscible fluids coexist in equilibrium in a porous medium, they are distributed according to the laws of hydrostatics and capillarity. The distribution of the fluids depends on the dimension of the pores, the contact angle, the interfacial tension and the saturation S_W and S_O.

In practice, the variation of the capillary pressure was experimentally determined.

$$\Delta P_c = P_c L/\gamma \tag{4}$$

Where L is the characteristic length of the medium, for example the average pore diameter, in our case we use the channel height that was practiced in the cell of the cell (4 mm), Eq. 4 allows the drainage on determined imbibitions curves, Fig. 3.

Curves I and D comprise the hysteresis loop of capillary pressure. This means that for a certain state of saturation of the porous medium, the given capillary pressure in the real distribution of the fluids depends on the previous history of the system evolution.

The drain and saturation experiments show that it is not possible for one of the fluids to be displaced completely by the other. In both displacement cases there is a residual saturation of 20 %, which corresponds to a fluid in form of beads disconnected from one another and trapped by capillary force.

The motion of a single-phase fluid in a porous medium is dependent on one specific property of the medium called permeability, this can be found experimentally by determining the relationship between the velocity of a fluid movement and the pressure drop produced.

$$u = (k/\eta)(dP/dL) \tag{5}$$

Darcy's law (Eq. 5, is a linear relationship that satisfies the low speeds involved: where u is the specific speed or filtration speed, i.e. the volumetric flow per unit area of the medium it passes through, the viscosity η, fluid, dP/dL is the pressure gradient (also comprises hydrostatic pressure).

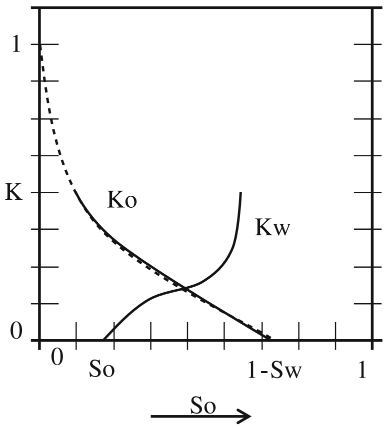


Fig. 4 Graphical permeability determined in a core of 20 cm height and 5.0 cm radius, extracted from Cantarel Reservoir

The Eq. 5 is equivalent to the Poiseuille Equation for a cylindrical capillary, and to involve all the pores, it incorporates a factor (0.125R2):

$$v = (R^2/8\eta)(dP/dL) \tag{6}$$

By defining Eq. 6 for each of the fluids involved in the experiment, it was found that the effective permeability was lower than the permeability of the porous medium.

The ratio of the effective permeability and the one of the medium is defined as the relative permeability *K*.

$$K_0 = k_O/k, \qquad K_W = k_W/k \tag{7}$$

For a core of 20.0 cm high and 5.0 cm radius, graphs of relative permeability were constructed as a function of saturations SW and SW, Fig. 4.

4 Conclusions

In order for the displacement of fluids to take place it is necessary that the displacing fluid possess more energy than the displaced one. As the first fluid is injected, a separation front starts appearing and two zones in the cell are well distinguishable, one of them is called non-invaded, where an oil bank is being formed due to the oil displacing forward. Behind that bank is the invaded zone, which was formed by the injected fluid and the remaining oil.

In order to improve the recovery of oil it is required to develop a chemical formula that can alter the preference wettability of the oil and water, which reduces the low surface tension in such a way that the capillary effect of the oil is broken and can be driven by gravity effect, and the permeability between layers can be changed by the crossed flow.

Chemical products injected can be introduced in the zones of less permeability, not only by spontaneous imbibitions, but also by the foam that diverts the liquid in the lower permeability layer. The foam as mobility control can also improve the efficiency of sweeping.

As a result in each of the flow processes, the foam is usually injected after low surface tension. The disadvantage in lowering the surface tension of the surfactant is in the lack of mobility control, generating a poor swept. It is ideal that the formulation of surfactants can simultaneously reduce the surface tension to very low values and generate strong foams which generate microscopic displacement and an efficient swept of the reservoir.

The laboratory-scale dimensions are totally different from the reservoir, as a consequence, several aspects need to be considered when extrapolating results.

The effect of gravity cannot be neglected in a field of several meters thick, or in the case of a sloping site. The reservoir thickness produces gravitational segregation with higher saturation of oil in the upper part, therefore conditions along the vertical axis change.

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