DETERMINATION OF FLUID FLOW PROPERTIES USING CAPILLARY PRESSURE CURVES

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Abstract
Capillary pressure values obtained from experiments can be used to characterize fluid flow in an oil reservoir. The data could also be used to obtain the pore size distribution in each sample, which is a vital tool for explaining the fluid flow properties. This will be another method to determine characteristics of rocks. A plot of capillary pressure vs. saturation for a rock core, called capillary pressure curve, can be used either to calculate reserves or in reservoir simulation computers routine. These curves also provide data on the irreducible water saturation of a reservoir rock and the entry pressure of oil into a water-saturated reservoir or cap rock.

The three available methods for obtaining capillary pressure curves are the porous plate, mercury injection and centrifuge methods. Due to some advantages over the two other methods, the centrifuge methods are widely used. Any fluid combination (air-oil, water-air, water-oil, and air-water-oil) can be used to obtain the capillary pressure curve.

In this study we use three types of cores i.e. sandstone, limestone, and dolomite. Each type is examined by the centrifuge method to compare the average and end-face saturations. Furthermore, pore size distribution and fluid flow in each type is calculated.

Introduction

The centrifuge method developed for evaluating the pore size distribution, accurate calculation of the inlet saturation, shape of capillary pressure curves, residual wetting phase saturation and etc. Capillary pressure may be a major factor to control the fluid flow through porous media. For example in water injection in some fractured reservoirs, imbibition capillary pressure is dominant force in the recovery of oil from matrix blocks compared with gravity and viscous forces. The first experiments with a centrifuge in petroleum industry are referred to McCullough et al [1]. They measured saturation by electrical conductivity of the sample. McCullough et al did not mentioned the effect of cavitation (bubble formation in liquid phase) in capillary pressure measurement. Slobad et al [2] found a correlation between the irreducible water saturation measured in the centrifuge and porous plate method. They showed that drainage capillary pressure curve which is produced by centrifuge were reproducible and matched those of the porous plate. Szobo [3] obtained imbibition capillary pressure curves by centrifuge and extended the capabilities of centrifuge method. Hassler and Brunner [4] developed a centrifuge method for determination of capillary pressure for small cores by using a small increase at centrifuge speed (rpm) and following time for saturation equilibrium in the cores at each step. They presented an approximation for converting measured average saturation to end-face saturation (end of the core closest to center of rotation) and proposed a criterion to validate the methods. The average fluid saturation and amount of fluid displaced is measured at each step. Hassler and Brunner also presented and approximate method for correction of the average saturation to obtain end-face saturation.

Centrifuge Method

The centrifuge technique has been widely used in the oil and gas industry for determination physical properties of reservoir rock core samples, and specially for measuring experimentally capillary pressure behavior. Other applications include measuring wettability, electrical properties, relative permeability and performing recovery study. The centrifuge method entails increasing the centrifuge speed in steps and measuring at each step the amount of liquid produced from the core at equilibrium, when all flow has ceased. An important assumption in analyzing this experiment is to assume that capillary pressure at outflow end is equal zero. Usual measurements are made in imbibition or drainage mode where oil or water can be wetting phase. However, there are other possibilities, e.g., secondary drainage from a core initially saturated at water flood residual oil and imbibition into a core at irreducible water saturation. The most pressing problem with the centrifuge techniques is focused on the validity of the fundamental assumption associated with the Hassler-Brunner equation. These include assumption of zero capillary pressure at the outlet end face of the core plug. In this study, merely for simplicity, the core is assumed to be initially 100% saturated with displaced phase. The phase entering the core is referred to as the invading phase.

Hassler-Brunner Theory

Modern centrifuge techniques are primarily based on the pioneer work by Hassler and Brunner, although centrifuge was used much earlier. The centrifuge method consist in measuring mean saturation values, $\overline{S}$ versus capillary pressure, P_{ci} at the inlet end face of the sample at equilibrium during rotation at various angular velocities, ω .

Several assumption have to be made in order to obtain an accurate approximation of explicit solution (an exact closed-form solution is unavailable) for a capillary pressure curve, the most important of which is that one-dimensional centrifugal force field exists inside the core plug. The classic Hassler-Brunner saturation equation, also known as the fundamental equation, is written as:

$$S_{(pci)} = S_{HB} = \overline{S}_{(pci)} + P_{ci}\frac{d\overline{S}_{(pci)}}{dP_{ci}} \quad (1)$$

The equation for capillary pressure in a centrifuge force field developed by Hassler-Brunner and demonstrated for small cores by Slobod et al. is derived beginning with the equation for capillary rise in a straight tube:

$$P_c = \Delta\rho g h = 1.179e-5\Delta\rho N^2 hr \quad (2)$$

Integrating across the length of the core to the outer radius, r_2 :

$$P_{c1} = P_{c2} + 1.179 * 10^{-5} \Delta\rho((r_1^2 - r_2^2)/2) \qquad (3)$$

Capillary pressure and saturation gradients exist in the core under centrifugal force, but the only measured quantities are revolution per minute (N) and the average saturation of the core (S_a). Hassler and Brunner assumed that the outer face of the core remains 100% saturated with the wetting phase at all centrifugal speed; consequently the capillary pressure at the outer face (P_{c2}) is zero. This leads to the equation for the centrifuge capillary pressure measurement adjusted to accommodate valuable core lengths:

$$P_{c1} = 1.588 * 10^{-7} \Delta\rho(r - l/2) * l * N^2 \qquad (4)$$

Experiments

Three different rock types have been selected. In this study the centrifuge method was used to obtain the capillary pressure curves. The Beckman Model LH-M Ultracentrifuge was also used in the study. The core sample was saturated with the wetting phase (brine) and rotated in the non-wetting phase (cornation oil, ρ =0.87 g/cc, μ = 19 c.p, σ_{o-w} = 35 mN/m) at increasing speeds up to some maximum value. The average water saturations at each speed were calculated from observations of the brine produced which is read from a stroboscope while the centrifuge is rotating. The petrophysical of the samples are shown in Table 1. Figure 1-3 also compares $P_{c|}$ as a function of S_a and S_1 illustrating, graphically the difference between the average and inlet saturations corresponding to the inlet capillary pressure. The correct capillary pressure curve is then $P_{c1} = f(S_1)$.

The capillary pressure at the inlet face of the core is calculated from Eq. 4. The average saturation and the amount of fluid displaced is measured at each step for each type of the core and the inlet saturation is determined.

Pore entry Size distribution

The capillary pressure curves can be used to infer a pore size distribution, which is useful for the analysis of problems associated with fluid flow characterization. One can not state that the pore size distribution which is exact because it is based on simplifying assumption, but its measurement is reproducible for repeated experiments. There are three general methods, which may be employed to measure the pore size distribution in naturally occurring rock formations. We used the method employed by Purcell [5] in an investigating of capillary pressure in reservoir rocks, and by drake and Ritter [6] bin the measurement of pore size distribution of the catalysts uses“non-wetting” fluid mercury. The technique of drake and Ritter, with modification has been applied to the study of the pore entry radii and the distribution of pore volume with pore entry radii in reservoir rocks. The radii of pores are then related to capillary pressure by:

$$R_i = \frac{2\sigma COS\theta}{P_c} \qquad (5)$$

The distribution function can be obtained by differentiation of the capillary pressure versus saturation curve as follow:

$$D(r_i) = (P_c \frac{PV}{r}) \frac{dS}{dP_c} \quad (6)$$

Graphical representations of pore size distribution as a function of pore entry radius for all types are shown in Figs 4-6.

Results and Discussion

Fluid flow Characteristics

The pore size distribution and wettability of the rocks may be an index for judgments about fluid flow characteristics of a rock which represents another method for evaluation of reservoir rocks. The term relative volumetric flow may be defined as the ratio of the “rate of fluid flow through an arbitrary interval of pore sizes” to the “total flow rate of the core” [7]. The equation for the relative volumetric flow was derived using the theoretical argument for the calculation of absolute permeability from the pore size distribution, which was represented by Burdine et.al [8]. They began with Poiseulli equation, which can be used to calculate the volumetric flow rate of a straight capillary tube of uniform size, assuming laminar, steady state, and incompressible flow:

$$Q = \frac{(\pi r^4 \Delta P)}{(8\mu L)} \quad (7)$$

Total flow rate of a group of a capillary of various sizes may be determined from the sum of the flow rate in each tube:

$$Q_t = (\pi \Delta P / 8\mu L) \sum n_i r_a^4 \quad (8)$$

Defining the number of capillary as the total volume of the tubes divided by the volume of a single tube and substitute in above equation, yield that:

$$n_i = V_t / (\pi r_a^2 l) \quad (9)$$

The relative volumetric flow is obtained by dividing the flow rate of pore sizes by the total flow rate of the group of the capillaries summed over the entries pore size distribution:

$$Q_t = (\pi \Delta p / 8\mu l) \sum_1^t (V_i r_a / \pi l) \quad (10)$$

$$Q_{rel} = \sum_l^m V_i r_a^2 / \sum_1^t V_i r_a^2 \quad (11)$$

The calculated relative flows with respect to the relative pore volume are shown in table 2. The relative volume of each group of pore radii (in Percent) to the total pore volume is listed in column 2 of table 2, and relative flow for each group is listed in column 3. Graphical representation of the pore size distribution as functions of pore entry radius are shown in figs 4-6. These graphs can be used to analyze the single phase flow through the core with the respect to the distribution of pore sizes. The area under the pore size distribution curve represents the pore volume of the porous medium:

$$PV_{cal} = Area + PV * S_{iw} \quad (12)$$

Table 2 represents the range that contains the immobile, irreducible saturation whose volume is equal to the total pore volume multiplied by the irreducible saturation (S_{iw}); this was selected as the first range of sizes with a flow arte equal to zero. The remaining groups of the pore sizes were arbitrarily divided into many groups, as shown in the first column of Table 2. The volume of each group of pore radii (second column of table2) was obtained by integration of distribution curve (Figs. 4-6) between the limits of the radii for each group. The relative volume of each group of pore radii to the total pore volume is listed in column 2 of table 2 and relative flow for each group is listed in column 3. The histogram in figs 7-9 compares the relative pore volume to the relative flow rate (column 3,4, table 2). The pore size ranges 0-0.41 for dolomite, 0-0, 36 for limestone, 0-0,94 for sandstone, representing the irreducible saturation, which does not conduct any of the fluid. The pore size ranges 0.42-0.73 for dolomite, 0.37-1, 25 for limestone, 0.95-2.1 for sandstone conducts 12.5, 13.2 and 2.6 percent of the total fluid flowing respectively. The pore size ranges 0.74 -1 for dolomite, 1.26-2.7 for limestone, and 2.11-2.7 for sandstone conducts 32, 36.3 and 17.2 percent of the total fluid flowing respectively. The pore size ranges 1-1.14, for dolomite, 2.71-3.4 for limestone, and 2.71-3.41 for sandstone conducts 55, 50.6 and 34.1 percent of total fluid flowing respectively. Finally only in the sandstone pore size range of 3.42-4.26 conducts 46.1 percent of the total fluid flowing respectively.

Thus this analysis yields a direct comparison of the pore volumes of ranges of pore radii to the relative amount, or relative rate, of flow within the porous medium. The analysis also provides a method for comparison of the fluid flow properties of different rocks, for example in dolomite 9 percent of pore volume is occupied by non-flowing irreducible water whereas 25.2 percent of limestone pore volume and 15.2 percent of sandstone pore volume are occupied by the irreducible water saturation.

Conclusion

1- In this paper we demonstrate the Hassler-Brunner solution for three types of core. This method is rapid to operate, accurate and simple for use. For the sandstone sample the calculated P_c curves from both experiment and H-B method are shifted to lower saturation with respect to the other two rock types because the sandstone has the higher porosity and permeability.

2- A useful method for characterizing the fluid flow properties of rocks based on the pore size distribution has been developed. These methods are examined on three types of core.

References

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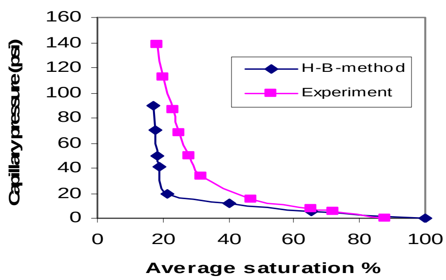

Fig.1- Capillary pressure curve (Dolomite)

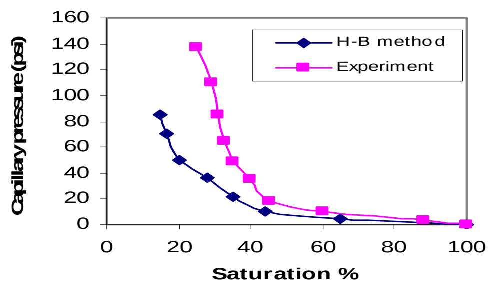

Fig.2-Capillary pressure curve (Limestone)

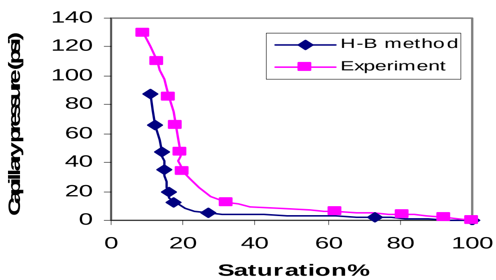

Fig 3- Capillary pressure curve (Sandstone)

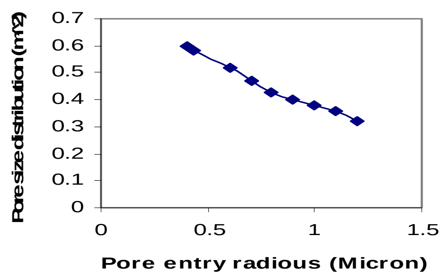

Fig.4-PSD curve for Dolomite

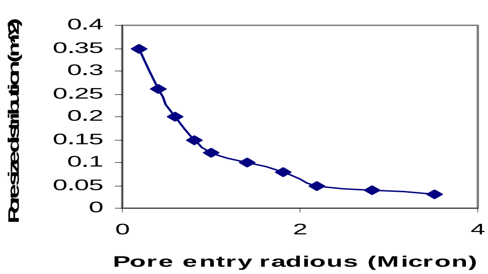

Fig.5-PSD curve for Limestone

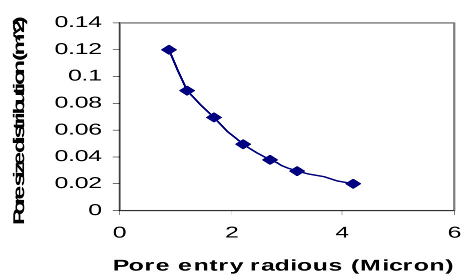

Fig.6-PSD curve for Sandstone

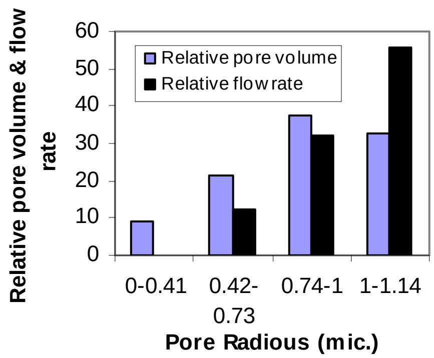

Fig.7-Histogram for Dolomite

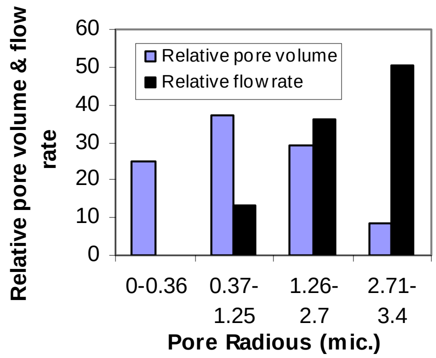

Fig.8-Histogram for Limestone

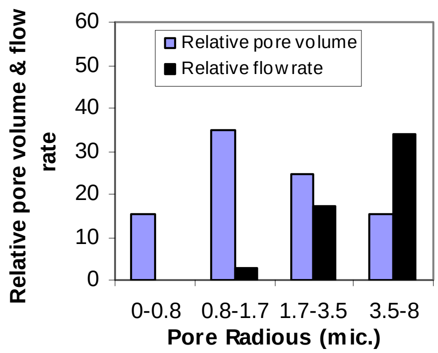

Fig.9-Histogram for Sandstone