EVALUATION OF FRACTURE APERTURE AND WETTABILITY, CAPILLARY PROPERTIES OF OIL-BEARING FRACTURED GRANITE

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ABSTRACT : Oil-bearing fractured rocks of a crystalline granite basement has been discovered offshore Viet Nam. For this type of rock, fracture is the main factor controlling the rocks permeability. Based on a large number of core analysis data, pore space of the rock was divided into the following main elements: macrofracture, matrix with microfractures and tight non-permeable matrix.

Cores of full sizes were used to determine the rock porosity, permeability and petrophysical properties. Contribution of each pore element was evaluated by air-water capillary pressure curve. From this analysis, the main contribution of pore volume is matrix with microfractures. Physical models of fractured granite of a single or double macrofracture and matrix with microfractures had been created. Electrical resistivity and water permeability of this media were measured simultaneously in Hassler cell at two saturation states: full and partial brine saturations (nonconductive matrix). By controlling effective overburden pressure, fracture aperture and sample's permeability were varied and a good relationship between resistivity and permeability were obtained in both cases of saturation. Hysteresis behavior of resistivity and permeability versus overburden pressure was investigated and large hysteresis was found. Comparison of these results shows that the apertures calculated from resistivity data are systematically more than those from permeability data, but in good relationship.

In this paper, laboratory data of rock wettability, capillary properties are reported. For such a type of collector, these characteristics are the main factors in controlling the oil recovery process. Integral wettability was determined by modified Amott-method. Separate determination of wettability of the fracture surface and matrix was carried out by contact-angle method. Results of these studies show that rock matrix is typically water wet (hydrophilic) and wettability of fracture surface changes in wide range from hydrophilic to hydrophobic, but in most cases is intermediate wet. Intensity of the oil-water capillary exchange process was studied under restored reservoir conditions and the numbers of curves of oil displacement coefficient versus time were obtained.

INTRODUCTION

Oil-bearing fractured granite is a major productive formation of the BACH HO field offshore Viet Nam. This is a rare type of reservoir rocks with numbers of specific characteristics, which differed from traditional sedimentary rock and fractured carbonate, on which were dedicated many publications.

Complex reservoir studies show that fractured granite had been formed during several processes such as weathering, shrinkage of hot intrusive rocks, tectonic movement and hydrothermal process. As a result, fractured granite is characterized by its heterogeneity and specific pore structure consisting of three main elements: macrofractures, low permeable matrix with macrofractures and tight non-permeable matrix.

It is widely acknowledged that fractures have an important role in the filtration of hydrocarbons in the reservoir although the main pore volume belongs to the matrix with microfractures. Permeability of fractured rock depends mainly on the fracture density and their aperture, therefore fracture study is essential to characterize the reservoir.

For such heterogeneous rock, wettability, capillary properties and fracture compressibility are among the major factors, which have strong effects on the oil recovery process. Wettability has more importance because the reservoir is being waterflooded and in this case the oil recovery mechanism in low permeable microfractured blocks is determined mainly by wettability and capillary properties.

In this paper we present the results of laboratory studies on these parameters of fractured granite. The reservoir was discovered at a depth in excess of 4000 m with high pressure and temperature (130-140°C), therefore it is important to carry out the experiments under similar condition. Due to the rock heterogeneity core of full size were used and there were also some specific procedures in dealing with these cores are presented.

PARTITION COEFFICIENT AND PETROPHYSICAL PROPERTIES

Procedures

Fracture reservoirs are commonly dual or possibly triple porosity and permeability system, where understanding of the control of the host rock porosity and permeability is as much a part of fracture study as recording fracture in core.

For determining the contribution of macrofractures and vugs in rock porosity we selected a collection of the most representative cores. The whole cores (D=6.7cm), after trimming and cleaning were saturated with synthetic formation brine(7 g/L NaCl) then the total porosity was determined. In order to avoid possible spontaneous brine loss from macrofractures due to gravitational and low capillary forces, core preparation should include the sealing of the fracture traces at the bottom end of the core by a thin glue ribbon.

Capillary pressure curves of these core were obtained by porous plate technique. Saturated samples were loaded into a capillary cell and Pc was increased in the following steps: 0.05; 0.1; 0.2; 0.5; 1; ... and 5 bar. At each Pc, water saturation (Sw) was determined.

Results and interpretation

These procedures were performed on 10 full size cores with permeability from 226 to 19250 mD, and total porosity from 3.03 to 9.93 % as shown in Table 1. Fracture and vug porosity was evaluated separately based on the effect of liquid capillary restrain in the pores. In the macrofractures, which provide major rock permeability, the larger fracture width (aperture), the lower capillary forces.

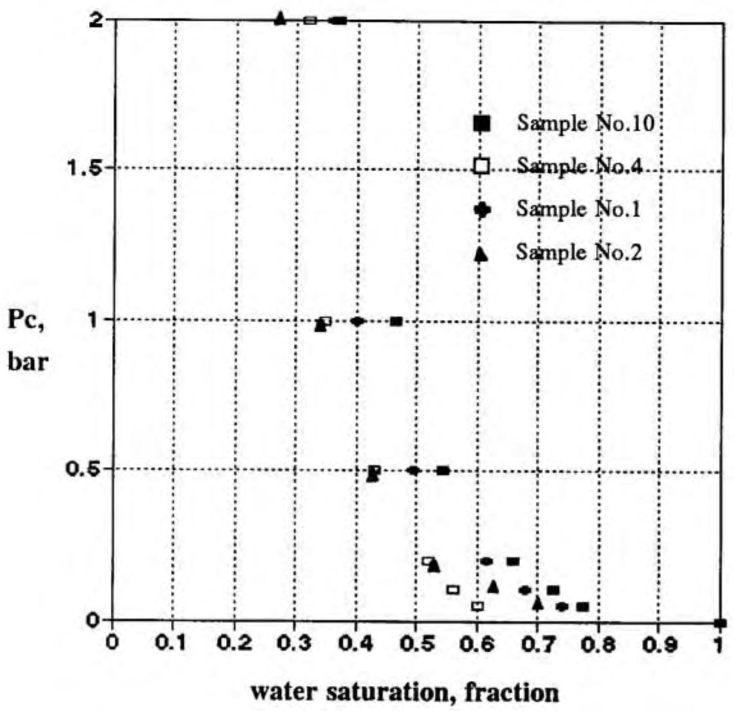


Fig. 1 : Air-water capillary pressure curves

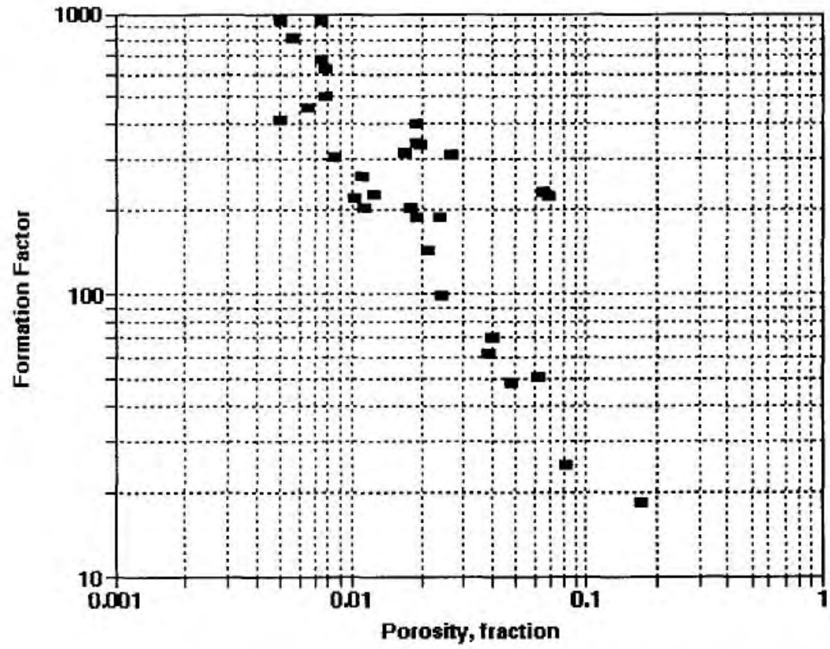
Table 1: Results of partition coefficient determination

Samples No	Permeability, mD	Total porosity, %	Partition coefficient
1	1800	8.33	0.328
2	19250	8.63	0.302
3	15220	4.25	0.435
4	1704	4.67	0.400
5	8520	3.03	0.396
6	386	4.34	0.260
7	824	9.93	0.266
8	514	5.54	0.462
9	226	4.06	0.370
10	302	7.69	0.223

Using this approach, we consider that the drastic change of the slope of the capillary pressure curve at low pressure should correspond to the volume of macrofracture and adjacent vugs. As shown on Fig.1, in all Pc curves it is very easy to determine the point of drastic slope change with corresponding saturation S_w*. Fracture and vugs porosity ($\varnothing_F$) was calculated by: $\varnothing_F = \varnothing_T(1-S_w*)$ and partition coefficient: $C = \varnothing_F/\varnothing_T$, where $\varnothing_T$ is total porosity. For these cores (table 1) partition coefficient was evaluated from 0.266 to 0.462 (on average 0.344), which show the major contribution of matrix with microfractures in rock porosity.

In previous works several methods were introduced to determine the partition coefficient of fractured rock. One of them was the method of interpretation of the curve of injection pressure versus injected volume of liquid (mercury or water). In another method, fracture porosity was evaluated by comparing the values obtained on the core containing fractures and then on the unfractured part of this core separately, or by calculation from the width of fracture traces visually determined on the core surface [Bagrinseva, 1982 *et.al*].

For the purpose of understanding the structure of the matrix with microfractures, resistivity measurement was performed on 31 fully brine saturated cores with K<3mD. Results presented on Fig.2 show a good relationship between the formation factor (FF) and porosity (∅) with cementation factor m = 1.36, which is significantly less than the common value of m for sandstones and carbonate rocks. Commonly for these rocks, m varying from 1.7 to 2.2 [Longeron, 1990].



$$FF = \frac{1}{\varnothing^{1.36}}$$

Fig. 2 : Formation resistivity factor vs. Porosity

FRACTURE APERTURE AND PERMEABILITY

Experiment

Simultaneous measurement of permeability (K) and resistivity (ρ) was performed on the models of fractured granite. The models were prepared as follows: the natural granite cores with filled fracture were selected for sampling plug cores of the required sizes (D=50 mm, L=50-80 mm). Drilling direction was chosen to be parallel with the fracture, so that the fracture traces appeared at the both ends of the plug. They were then mechanically broken by the fractures, and the filling material (friable secondary mineral) was cleaned up. All of broken parts were reassembled again by special glue. By this method, the fractures became open and it is believed that they have the same morphology as natural open fractures.

Measurement of permeability to water and resistivity of these samples was performed simultaneously in Hassler coreholder equipped with two silver-coated electrodes (Fig.3). For each sample, ρ and Kw were determined at various overburden pressure after one hour for stabilizing the stress state. The following steps of overburden were applied: 15, 50, 100, 200, 300, and 400 bar.

Samples of two saturation states were investigated:
a) Full brine saturation
b) Partial brine saturation.

For partial brine saturation, firstly samples were saturated with kerosene, then in the coreholder kerosene was displaced by water from high permeable macrofracture. In the results, the low permeable matrix was saturated with kerosene to be nonconductive such as in the well, where during drilling the mud filtrate invasion into high permeable canals (fractures) formed high contrast in resistivity between the matrix blocks and macrofractures.

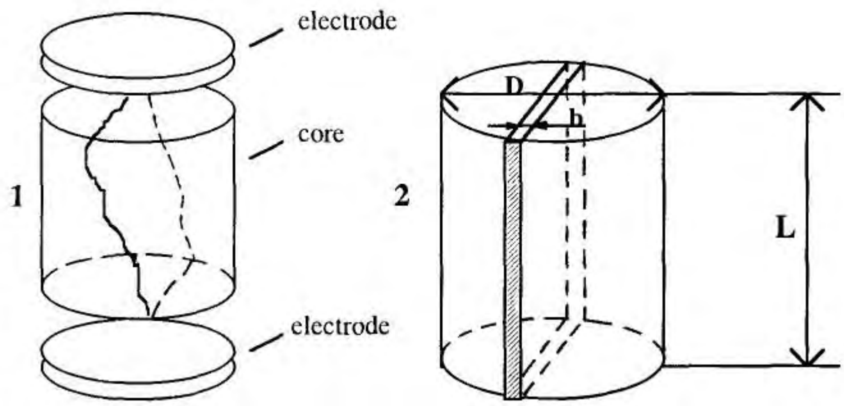


Fig. 3 : Test scheme (1) and simplified scheme of fracture in core (2)

Results and discussion

Results of experiments on 6 models of fractured granite are presented in Fig.4. The cross-plot in Fig.4 shows a relationship between the sample's resistivity and permeability in both cases of saturation. In the case of full brine saturation, the scatter at low permeability may be attributed to different conductivity of the matrix. It is obvious that when the macrofracture is compressed under pressure, its aperture is comparable with the aperture of microfractures in the matrix block, the contribution of matrix conductivity became essential.

These results allowed us to find out the relationship between aperture and permeability. Several authors [Reiss,1987,*et.al*] introduced the empirical formula, which express the relationship between K and fracture aperture for fractured media, as shown in Fig.3 :

$$K = 8.33 \cdot 10^{-4} \cdot b_1^{2} \cdot \varnothing_f ,$$

where : $\varnothing_f$ = fracture porosity, %,
b_1 = aperture, micrometre,
K = permeability, darcy.

For the fracture system, as shown schematically on Fig.3, fracture porosity can be expressed through b_1 as: $\varnothing_f = 4b_1 \cdot 10^{-2}/\pi D$, and we can re-write this formula as:

$$b_1 = \sqrt[3]{\frac{K \cdot \pi D}{33.32 \cdot n \cdot 10^{-6}}} ,$$

where: n = number of fracture in sample,
D = diameter of sample, cm.

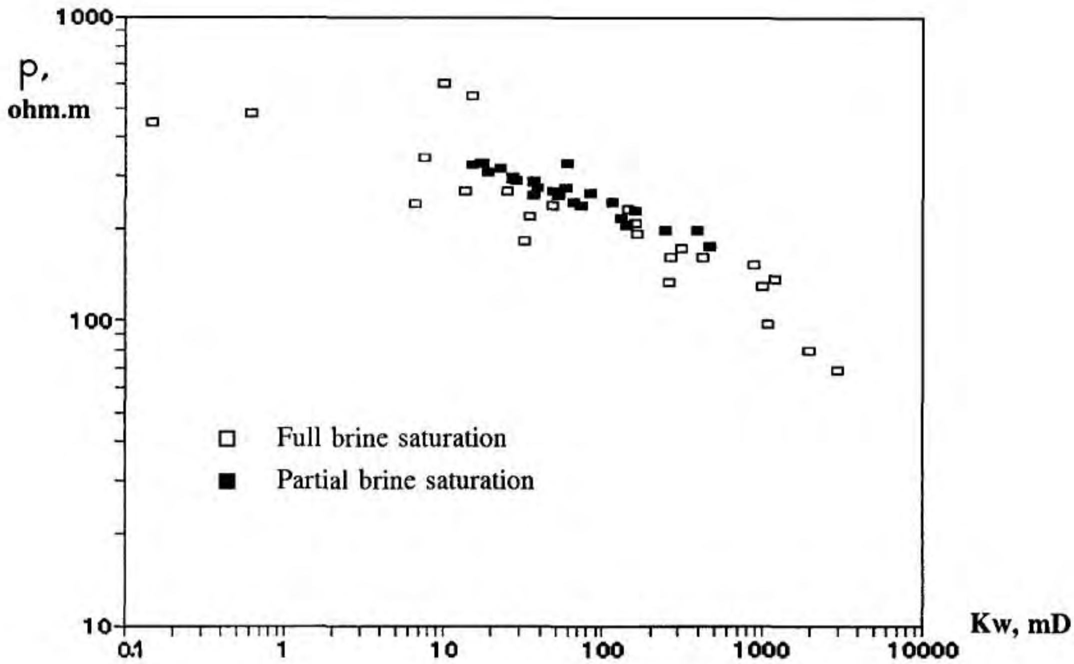


Fig. 4 : Cross-plot of resistivity versus permeability

Using the relationship between the resistance (R) of a conductive material and its size (length-L, cross-section-S): $R = \rho_w L/S$,

where: ρ_w- specific resistivity of a conductive material (brine),

in our case of fracture filled with brine as shown in Fig.3, we can also derive the fracture width from electrical data:

$$R_f = \rho_w \cdot \frac{L}{n \cdot b_2 \cdot D}, \text{ or } \quad b_2 = \frac{\rho_w \cdot L}{R_f \cdot D \cdot n}.$$

For simplicity we assumed that the fracture length was equal to the length of the sample-L.

In Fig.5 the values of fracture aperture calculated from two independent parameters (K & ρ) are compared. The cross-plot shows a linear relationship between the two values. The systematical exceeding of b_2 over b_1 can be explained by roughness of the fracture surface. Brown, 1987; Jones *et al.*,1988 noted that fluid flow rates through fractures with smooth surface are proportional to the cube of the aperture, but decrease with increasing roughness such as found on natural fracture surface. From this data, we consider that the values b_2 derived from resistivity express the real value of the fracture aperture.

For illustrating the hysteresis behavior of a fracture, the variations of K & ρ versus overburden at two increasing-decreasing cycles are shown in Fig.6. In pressure increasing direction, at both cycles we noted that the values of K & ρ became closer and at maximum P_{eff} = 400 bar, behavior of the fracture is elastic. The large hysteresis of K & ρ in decreasing direction indicates the unreversible compressibility of the fracture after pressure was lifted. We also noted that the hysteresis behavior of permeability and resistivity was very similar, which once more proves a strong relationship between them.

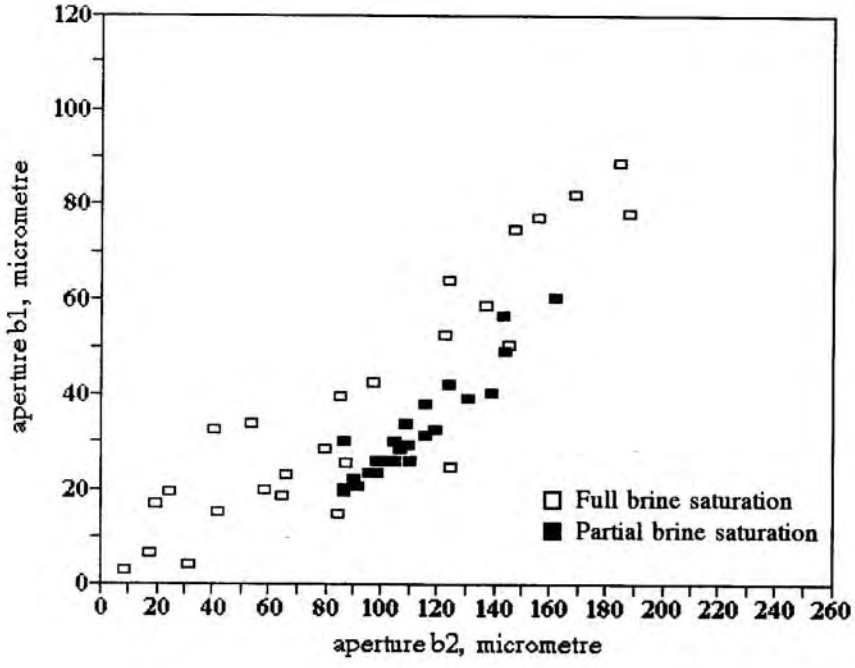


Fig. 5 : Comparison between fracture aperture calculated from resistivity (b2) and permeability data (b1)

WETTABILITY AND IMBIBITION CHARACTERISTICS

Wettability test

As described above, there are two main elements in the structure of fractured granite: macrofractures and matrix block containing microfractures. So determination of wettability characteristics of each pore element is of great interest.

Various methods for determining the wettability are described in literatures. We used the two most popular methods:

- Amott-IFP method: spontaneous water imbibition was performed in special cell at reservoir temperature T = 130-140°C and pressure P = 50 bar. In order to maintain these conditions, the imbibition cell was made from stainless steel and thick quartz graduated tube for visual determination of oil volume displaced during the test period. Forced displacement was performed in the Hassler coreholder on waterflooding apparatus at the same T and P.
- In the contact-angle method, the angle (θ) formed by oil drop on the rock surface under water was calculated from the sizes of drop as: $tg(\theta^*/2) = 2h/D$, where h = height and D = diameter of drop at the contact with rock and $\theta = 180° - \theta^*$. Rock wettability is classified as follows: water-wet (θ = 0-75°); intermediate wet (θ = 75 - 105°); oil-wet (θ = 105-180°), [Bagrinseva,1982].

The cores were first extracted in a soxhlet using benzene and alcohol then saturated with synthetic formation brine. Saturated cores were placed into a capillary pressure cell for simulating residual water saturation. Then the cores were saturated with crude oil and aged under pressure P = 50 bar and reservoir T for 7 days for restoration of the interaction between fluids and rock. After these procedures, the wettability of core was evaluated.

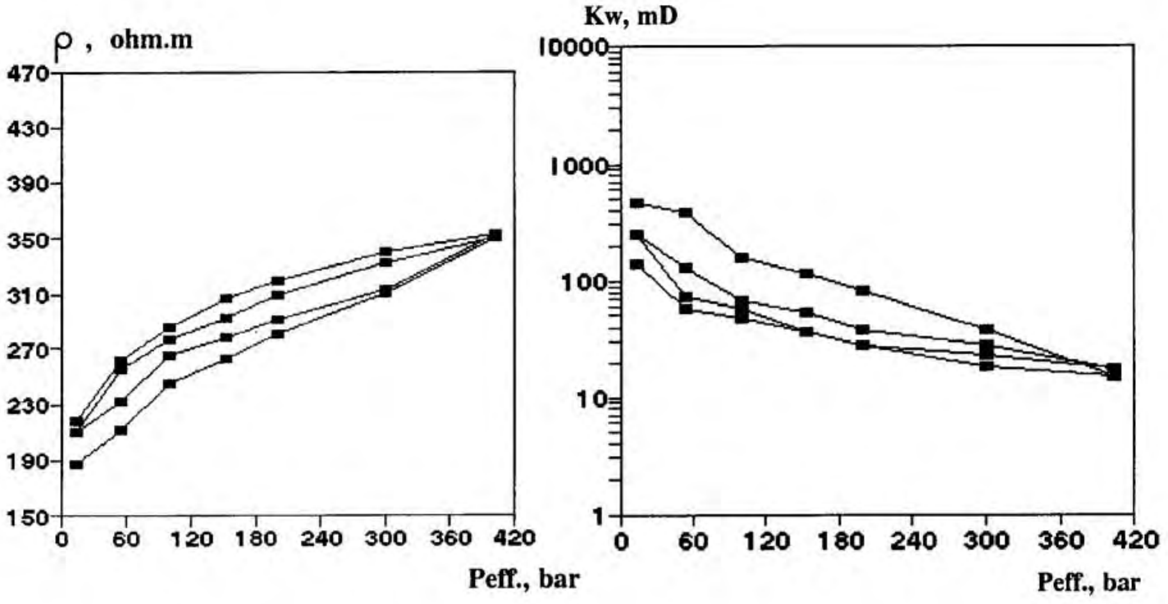


Fig. 6: Hysteresis behavior of fracture versus overburden pressure

Results

Plug samples (D=50 and 30 mm) were used for the determination of wettability index by Amott-IFP method. Contact-angle measurements were performed on the natural surface of the fracture and also on the cut surface of the matrix block containing microfractures.

Results of wettability determination presented in Table 2 show that, by Amott-IFP method, matrix block of fractured granite is water-wet with wettability index WI>0.8 for all samples. The same wettability characteristic of matrix block was confirmed by contact-angle measurements. Table 2 shows that the contact-angle varied from 41 to 62° for matrix block. For the natural fracture surface, θ varied from 75 to 112°, respectively corresponding to water-wet and slightly oil-wet. In most cases, wettability of fracture surface can be classified as intermediate wet. The phenomenon that the wettability characteristics of fracture surface became intermediate or preferentially oil-wet can be explained by its specific mineral composition. Macrofractures were affected by the circulation of hydrothermal solution and in the results on the fracture surface, several secondary minerals such as zeolite and calcite were formed. The presence of these minerals might cause the wettability change of the fracture surface.

Water-wet characteristic of low permeable matrix block is a favorable factor for spontaneous capillary exchange between oil saturated matrix and water saturated macrofracture during water flooding. Intensity of this process in heterogeneous fractured granite determines the rate of waterflooding in order to get maximum oil recovery. For comparison purpose, spontaneous imbibition was studied on the samples both with, and without residual water.

Fig.7 presents dynamics of oil displacement on the time for two pairs of samples with very close porosity (No.2-No.14 and No.3-No.9). We noted that for the samples without residual water, intensity of the spontaneous imbibition was less than in the case when the samples were initially saturated with residual water.

Table 2 : Wettability index and contact-angle

Sample No.	Ø, %	WI, fraction	θ, degrees	Number of measurements	Notes
1	5.42		70	1	fracture surface
			96	2	"
			46	1	cut surface
			50	2	"
2	8.73	0.91	86	1	fracture surface
		0.88	100	2	"
			75	3	"
			90	4	"
			55	1	cut surface
			48	2	"
3	4.56	0.87	107	1	fracture surface
			112	2	"
			102	3	"
			62	1	cut surface
			54	2	"
			50	1	"
			41	2	"

With the concept of imbibition velocity introduced by Ban and Rizhik, 1962 and based on the imbibition end time (t) and the sizes of the sample we obtained the characteristic imbibition velocity for matrix block, which ranged from 9.2 to $69.3 \cdot 10^{-6}$ cm^2/s (table 3). For the porosity Ø=2.88%, oil recovery $\eta=0.328$, which is significantly higher than for matrix of carbonte rocks with the same porosity ($\eta=0.2$) [Salko, Martyntsiv, 1986].

Table 3 : Oil recovery and velocity of spontaneous water imbibition

Sample No.	Ø, %	Swr, %	t, $\times 10^4 \cdot s$	Velocity, $\times 10^{-6} cm^2/s$	Oil recovery
1	4.25	40.4	24.5	45.8	0.499
2	3.03	36.2	37.8	9.2	0.581
3	8.63	30.9	24.5	45.8	0.499
4	5.54	28.1	32.9	24.3	0.431
5	4.34	33.1	23.9	25.7	0.457
6	9.93	34.1	22.3	37.7	0.397
7	4.06	38.5	10.9	69.3	0.457
8	4.67	41.9	23.0	27.4	0.563
8	4.67	0	26.1	24.1	0.541
9	8.33	0	38.9	16.8	0.382
10	2.76	0	14.4	42.2	0.320
11	6.45	0	21.6	17.6	0.328
12	5.73	0	14.9	19.4	0.176
13	9.09	0	18.0	20.1	0.251
14	2.88	0	25.2	25.2	0.328
15	3.80	0	20.9	36.9	0.431

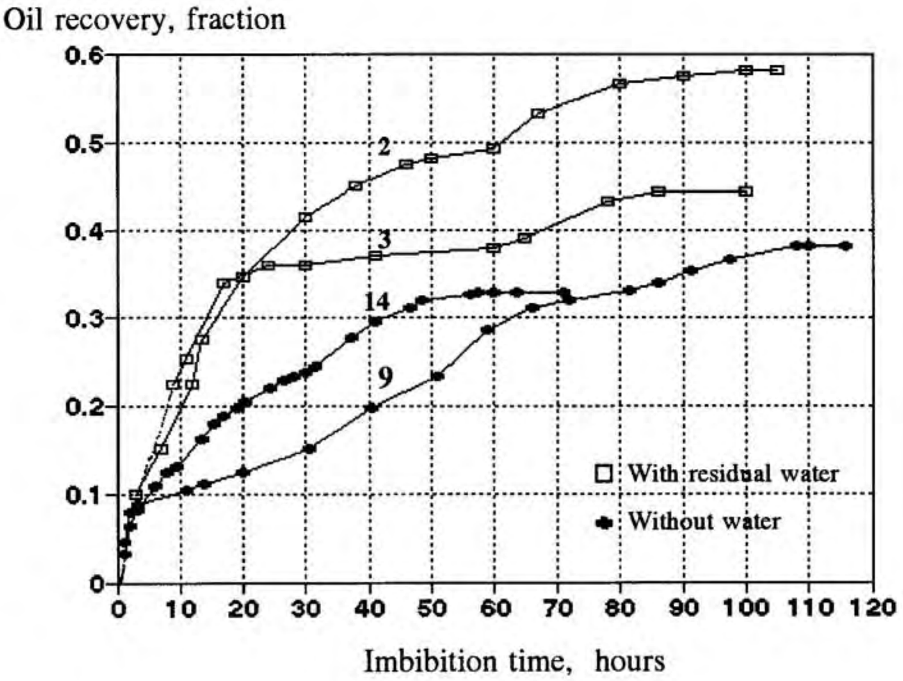


Fig. 7 : Dynamics of imbibition process

CONCLUSIONS

1. Air-water capillary pressure curves obtained on whole core were used to determined the partition coefficient of the fracture and vug porosity: the drastic slope change of Pc-curves corresponds to the fracture and vug porosity. For fracture granite, partition coefficient was evaluated from 0.226 to 0.462.

2. A good relationship between permeability and resistivity was obtained on the models of fractured granite. Different matrix conductivity does not have a strong influence on these parameters at high permeability, the dominant role belongs to the macrofracture.

3. Simultaneous measurement of permeability and resistivity provided the possibility of reconciliation of these data. Comparison of the apertures derived from permeability and resistivity data shows a good relationship but systematical exceeding of "resistivity" aperture over "permeability" aperture due to the roughness of fracture wall.

3. Separate measurements show different wettability characteristics of matrix block and fracture surface: microfractured matrix is typically water-wet and intermediate wettability of fracture surface.

4. Water-wet characteristic of low permeable matrix block supported high intensity and efficiency of water imbibition, which is higher than for fractured carbonate rock.

But saturation history had some unfavorable effect on oil recovery by spontaneous water imbibition.

NOMENCLATURE

b	= fracture aperture, micrometre	FF	= formation resistivity factor
K	= permeability, mD	Pc	= capillary pressure, bar
P_{eff}	= effective overburden, bar	R	= resistance, ohm
S_w	= water saturation, fraction	T	= temperature, °C
t	= imbibition time, sec.	∅	= porosity, fraction
WI	= wettability index	θ	= contact-angle, degrees
ρ	= resistivity, ohm.m	η	= oil recovery factor, fraction.

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