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# Appearance of Capillary End Effects in Filtration Studies

**Ivan S. Putilov, Denis B. Chizhov, Evgeniy A. Kochergin**

PermNIPIneft branch of LUKOIL-Engineering LLC in Perm (3a Permskaya st., Perm, 614015, Russian Federation)

# Проявление капиллярных концевых эффектов при фильтрационных исследованиях

**И.С. Путилов, Д.Б. Чижов, Е.А. Кочергин**

Филиал ООО «ЛУКОЙЛ-Инжиниринг» «ПермНИПИнефть» в г. Перми (Россия, 614015, г. Пермь, ул. Пермская, 3а)

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From theoretical studies and experiments on the core, the so-called capillary end effect is known, also called the effect of phases capillary entrapment. When carrying out laboratory experiments to determine the relative phase permeabilities, capillary end effects appear on the core models of the reservoir. These effects can occur as a result of capillary ruptures at the ends of the core sample, which leads to the accumulation of one phase in relation to the other, and thereby affects the movement and retention of the fluid. The region of capillary end effect, which occurs due to the rupture of capillaries at the exit from the sample, affects the change in pressure drop and saturation by a particular fluid. If the influence of capillary end effects is significant, then the experimental conditions are modeled incorrectly, which can lead to serious errors in predicting the productivity of the studied formation.
This paper presents the results of studying the porosity-permeability properties of determining the relative phase permeabilities and the analysis of the studies of the capillary end effects influence mechanism on the filtration capacity of rock samples during laboratory studies using the example of terrigenous and carbonate types of the Pavlovskoye reservoir. According to the results of the studies, the significance of capillary end effects in filtration experiments was established using the example of determining the relative phase permeabilities. Recommendations are given with the aim of minimizing the negative influence of the end effects. The capillary effects can be overcome by increasing the length of the test sample, as well as by increasing the fluid flow rate during a laboratory experiment to determine the relative phase permeabilities.

*Ключевые слова:*
относительные фазовые проницаемости (ОФП), капиллярные концевые эффекты, керн, пластовые условия, перепад давления, пластовые флюиды, пластовая нефть, пластовая вода, насыщенность флюидом, капиллярный разрыв, фильтрационные исследования, терригенные коллектора, карбонатные коллектора, пористость, газопроницаемость.

Из теоретических исследований и экспериментов на керне известен так называемый капиллярный концевой эффект, или, как его еще называют, эффект капиллярного защемления фаз. При проведении лабораторных экспериментов по определению относительных фазовых проницаемостей на керновых моделях пласта возникают капиллярные концевые эффекты. Данные эффекты могут возникать в результате капиллярных разрывов на концах образца керна, что приводит к накоплению одной фазы по отношению к другой, и тем самым влияют на движение и удержание флюида. Область капиллярного концевого эффекта, которая возникает вследствие разрыва капилляров на выходе из образца, оказывает влияние на изменение перепада давления и насыщенности определенным флюидом. Если влияние капиллярных концевых эффектов будет значительным, то условия проведения эксперимента моделируются неверно, что может привести к серьезным ошибкам при прогнозировании производительности изучаемого пласта.
Представлены результаты изучения фильтрационно-емкостных свойств определения относительных фазовых проницаемостей и анализ исследований механизма влияния капиллярных концевых эффектов на фильтрационную способность образцов горных пород во время проведения лабораторных исследований на примере терригенного и карбонатного типов коллектора Павловского месторождения. По результатам проведенных исследований установлена значимость капиллярных концевых эффектов при фильтрационных экспериментах на примере определения относительных фазовых проницаемостей. Даны рекомендации с целью максимального снижения отрицательного влияния концевых эффектов. Капиллярные эффекты могут преодолеваться путем увеличения длины исследуемого образца, а также с помощью возрастания расхода флюида в процессе проведения лабораторного эксперимента по определению относительных фазовых проницаемостей.

**Ivan S. Putilov** (Author ID in Scopus: 25723777700) – Doctor in Engineering, Deputy Director of the Branch for Scientific Work in the Field of Geology (tel.: +007 342 233 64 58, e-mail: Ivan.putilov@pnn.lukoil.com).
**Denis B. Chizhov** (Author ID in Scopus: 57112213900) – Head of the Department for Special Research of Core and Reservoir Fluids (tel.: +007 342 233 65 00, e-mail: Denis.Chizhov@pnn.lukoil.com). The contact person for correspondence.
**Evgeniy A. Kochergin** – 1st category Engineer at the Department of Physical and Hydrodynamic Research (tel.: +007 342 717 01 54, e-mail: Evgenij.Kochergin@pnn.lukoil.com).

**Путилов Иван Сергеевич** – заместитель директора филиала по научной работе в области геологии, доктор технических наук (тел.: +007 342 233 64 58, e-mail: Ivan.Putilov@pnn.lukoil.com).
**Чижов Денис Борисович** – начальник управления специальных исследований керна и пластовых флюидов (тел.: +007 342 233 65 00, e-mail: Denis.Chizhov@pnn.lukoil.com). Контактное лицо для переписки.
**Кочергин Евгений Александрович** – инженер I категории отдела физико-гидродинамических исследований (тел.: +007 342 717 01 54, e-mail: Evgenij.Kochergin@pnn.lukoil.com).

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## Introduction

Liquids inside oil reservoirs move around along extremely complicated systems of branching out pore channels that vary in size. THEREFORE a joint stream of two immiscible liquids, like oil and water, are marked by a vast, extremely curved interface surface that is affected by surface forces. Each of the phases moves within its system of pore channels maintaining continuity; however, at times a fluid particle can get into the channel filled with a different phase. It happens at high gradients of pressure [1].

There is theoretical and experimental evidence of the so-called capillary end effect, which is also known as the effect of capillary entrapment of phases. It is caused by the physical condition of continuity of pressures in phases both inside the porous medium and at the contact of two spans of the porous medium. Since pressures within phases are continuous, consequently, the capillary pressure should be continuous throughout the entire two-phase span.

This effect can be found around the contact of two spans of porous medium with different capillary properties. In this case the saturation of wetting phase changes around the boundary to a value that equalizes capillary pressures.

The end effect impact zone spans along the entire length of the complex model and can significantly affect the results of laboratory studies [2].

This article attempts to identify the capillary end effects in laboratory conditions, determine their significance and analyze their impact using filtration studies in reservoir conditions, namely, based on the determination of phase permeabilities.

Phase permeability is one of the most important parameters characterizing the reservoir fluid distribution process in oil and gas reservoir rock. Data on phase permeability are necessary for justifying saleable limits, petrophysical properties of rocks when making an industrial estimate of transient oil- and gas-bearing zones in the strata, gas-hydrodynamic calculations of technological indexes when choosing a method of impact on the stratum for enhanced oil recovery, as well as field development analysis and control.

## Conducted Studies

1. Selection and preparation of samples for filtration studies.

In order to identify and then estimate and compare the impact of capillary end effects depending on lithology and various degrees of heterogeneity, the study considered samples of the core from two lithologically different layers: Tournaisian (carbonate) and Visean (terrigenous) deposits. The samples were collected from two wells with high reservoir properties (Table 1).

The samples were sawed to the size of 80×30 mm oriented parallel to the layering (Fig. 1), and then prepared for filtration studies.

The core samples were washed in alcohol-benzene mixture to remove oil and bitumens using extraction in the Soxlet apparatus and dried in the cabinet to the fixed weight. Further, samples were characterized in terms of their reservoir properties: absolute gas permeability factor and connected porosity factor (Table 2).

The samples were then saturated with the reservoir water model that was basically a mineralized solution of NaCl with concentration of 234 g/l. The samples were weighed to calculate their pore volume.

After reservoir properties were determined, the prepared samples were placed inside the filtration unit (Fig. 2) which simulated the reservoir conditions and housed the experiments. The studies were conducted in the simulated reservoir conditions at the temperature of 25 ºC and under effective pressure of 5 MPa.

Fig. 1. Sawed samples

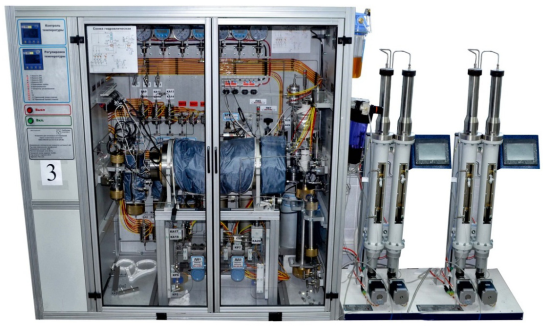

Fig. 2. Filtration unit ПИК-ОФП-2-1-4-СУ-70-40-АР-ЭС


Fig. 3. Composite sample model after repeat treatment

The studies featured the following fluids:

a) reservoir water model that was used to saturate the samples and determine the permeability coefficient to water ($K_{pw1}$);

b) isoviscous model of the Pavlovskoye field oil that was used to create the initial water saturation and determine the phase permeability to oil ($K_{po}$);

c) fresh water that was used as a displacement agent and to measure the phase permeability to water ($K_{pw2}$).

Residual water saturation was generated by means of displacement in the filtration unit in reservoir conditions.

The fluid parameters are given in Table 3.

2. Studies conducted using samples 80×30 mm in size.

Filtration testing started with measuring permeability to reservoir water. The reservoir water was filtrated step by step, at 5 different flow rates, to the point of stabilization of differential pressure but not less than 3 porous volumes.

The prepared sample was then put through tests to determine steady-state filtration using the relative phase permeability (RPP) method in accordance with OST 39-235-89 in conditions that are as close to the reservoir reality as possible. Fluids (oil, water) were injected in various modes. In each mode, the fluids were injected up to the point of stabilization of differential pressure, resistance, and ratio of injected and displaced phase volumes [3].

At the end of the experiment permeability was measured to displacement agent in the sample with residual oil saturation (Table 4).

Table 1

Core samples for the research

| Field | Sample number | Age | Depth, m | Lithologic description | Gas permeability, $10^{-3}$μm$^2$ | Porosity, % |
|---|---|---|---|---|---|---|
| Pavlovskoye | 22-448-14 | $C_1t$ | 1459.31 | Brown limestone, oil-saturated, highly porous, with fine caverns formed around organic remains, solid | 385.96 | 18.30 |
| Pavlovskoye | 8-599-15 | $C_1tl_т$ | 1433.15 | Dark brown sandstone, intensely oil-saturated, fine-grained, with singular grains of medium size, highly porous, solid | 428.98 | 20.11 |

Table 2

Reservoir properties of samples

| Sample number | Reservoir type | Length *L*, cm | Diameter *D*, cm | Porosity, % | Gas permeability, $10^{-3}$μm$^2$ | Pore volume, cm$^3$ | Residual water saturation, u.f. |
|---|---|---|---|---|---|---|---|
| 22-448-14 | Carbonate | 8.02 | 2.95 | 18.61 | 376.15 | 11.76 | 0.120 |
| 8-599-15 | Terrigenous | 7.82 | 2.91 | 20.99 | 411.13 | 12.59 | 0.270 |

Table 3

Fluid parameters

| Fluid | | Viscosity in reservoir conditions, mPa·s | Density, g/cm$^3$ | Temperature, °C |
|---|---|---|---|---|
| Reservoir water model | | 1.56 | 1.146 | 25 |
| Oil model | Terrigenous reservoir | 3.38 | 0.828 | 25 |
| | Carbonate reservoir | 3.51 | 0.835 | 25 |
| Fresh water | | 1.00 | 1.00 | 25 |

Table 4

Measurement of permeability to displacement agent

| Reservoir type | Permeability coefficient, $10^{-3}$μm$^2$ | | | |
|---|---|---|---|---|
| | to gas | to water 234 g/l | to oil at residual water saturation | to water at residual oil saturation |
| Terrigenous | 411.13 | 340.76 | 82.49 | 11.51 |
| Carbonate | 376.15 | 303.90 | 64.55 | 10.09 |

3. Repeat treatment.

After completing the filtration tests using the core of 80×30 mm, the samples went through the repeat treatment that included the following:

– extraction (removal of oil and bitumens from the rock);

– sawing of the 80×30 mm core into three identical samples;

– determination of reservoir properties of the samples.

The repeat treatment resulted in the formation of composite models (Fig. 3).

The results of reservoir properties are presented in Table 5.

4. Conducted studies with composite models.

Filtration tests were carried out using the same technique as in Procedure 2. The results of laboratory tests are presented in Table 6.

## Analysis of Filtration Test Results

The results of the laboratory tests were compiled into tables for comparison, graphs were drawn to make conclusions about the role of end effects on reservoir properties of rocks.

The capillary end effect results from erupting capillars on the way out of the sample, which leads to accumulation of one phase in relation to another and affects the measurement of differential pressure and saturation in the experiment aimed at determining phase permeabilities.

The results of tests are given in Table 7 to compare reservoir properties and saturation of the 80×30 mm samples and composite models after the repeat treatment.

When comparing saturation, it is necessary to identify an increase in water saturation and a drop in oil saturation in composite models. For example, a solid carbonate-type sample in the mode of 50 % water with 50 % of oil demonstrates water saturation at 0.41 u.f., whereas a composite model is at 0.56 u.f. This confirms the presence of capillary end effects during filtration tests.

At the beginning of studies, absolute permeability was measured on the reservoir water model using solid samples 80×30 mm in size, which were then sawed into three approximately identical samples to measure permeability using the composite model. The measurements were made at various flow rates (Fig. 4, 5).

The results in the graphs suggest that absolute permeability of the composite model be lower than that of the solid 80×30 mm sample. It is worth noting that the terrigenous sample shows a minor decrease to 17 % in comparison with the carbonate sample where it can drop by as much as 40 %. This decrease in permeability is due to the erupting capillars on the way out of the sample, which results in one phase building up in relation to another and affects the measurements of differential pressure and saturation.

Another important observation is that at higher fluid filtration rates the impact of capillary effects is reduced.

After conducting the experiment on determination of RPP, it can be concluded that phase permeabilities to the composite model are lower than those to the solid sample, which further confirms the impact of capillary end effects. Comparing the terrigenous reservoir in the solid and composite samples, there are slight deviations of relative permeabilities and water cuts (Fig. 5, *a*). The carbonate type showed more pronounced deviations: the composite sample had higher actual water saturation, while oil saturation was lower at every step of the experiment in comparison with the solid sample (Fig. 5, *b*).

## Conclusion

The analysis of results obtained in the studies confirmed manifestation of capillary end effects that occur on the butts of certain composite model samples, namely:

- the comparison of saturation values showed an increase in water saturation and a decrease in oil saturation in composite models;
- the comparison of permeabilities revealed a drop in permeability in composite samples.

It is also found that at higher fluid filtration rates the impact of capillary effects is reduced.

Table 5

Resulting porosity and permeability properties

| Field | Reservoir type | Sample no. | *L*, cm | *D*, cm | $K_p$, % | $K_p$ to gas, $10^{-3}$ μm² | Pore volume, cm³ | Residual water saturation, u.f. |
|---|---|---|---|---|---|---|---|---|
| Pavlovskoye | Terrigenous | a | 2.46 | 2.91 | 21.0 | 504.9 | 3.41 | 0.28 |
| | | b | 2.30 | 2.91 | 21.02 | 486.0 | 3.21 | |
| | | c | 2.60 | 2.91 | 21.05 | 458.7 | 3.58 | |
| | Carbonate | a | 2.82 | 2.94 | 18.02 | 396.5 | 3.30 | 0.14 |
| | | b | 2.33 | 2.95 | 18.53 | 476 | 2.82 | |
| | | c | 2.43 | 2.95 | 18.06 | 383.3 | 2.91 | |

Table 6

Laboratory test results

| Reservoir type | Permeability coefficient, $10^{-3}$ μm² | | | |
|---|---|---|---|---|
| | to gas | to water 234 g/l | to oil at residual water saturation | to water at residual oil saturation |
| Terrigenous | 483.20 | 315.69 | 53.87 | 10.23 |
| Carbonate | 418.60 | 255.43 | 21.25 | 3.67 |

Table 7

Test results

| Reservoir type | *L*, cm | *D*, cm | $K_p$, % | $K_p$ to gas, $10^{-3}$ μm² | Pore volume, cm³ | Residual water saturation, u.f. | Residual oil saturation, u.f. |
|---|---|---|---|---|---|---|---|
| Terrigenous (solid) | 7.82 | 2.91 | 20.99 | 411.13 | 12.59 | 0.27 | 0.35 |
| Terrigenous (composite) | 7.34 | 2.91 | 21.02 | 483.2 | 10.2 | 0.28 | 0.31 |
| Carbonate (solid) | 8.02 | 2.95 | 18.61 | 376.15 | 11.76 | 0.12 | 0.40 |
| Carbonate (composite) | 7.58 | 2.95 | 18.61 | 418.6 | 9 | 0.14 | 0.28 |

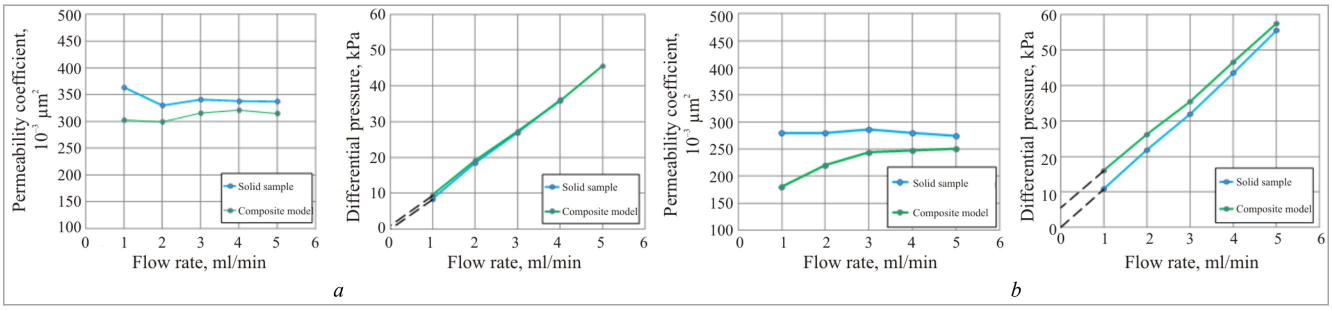


Fig. 4. Graphs of dependence of the absolute permeability coefficient and differential pressure on a certain flow rate: *a* – for the terrigenous sample; *b* – for the carbonate sample

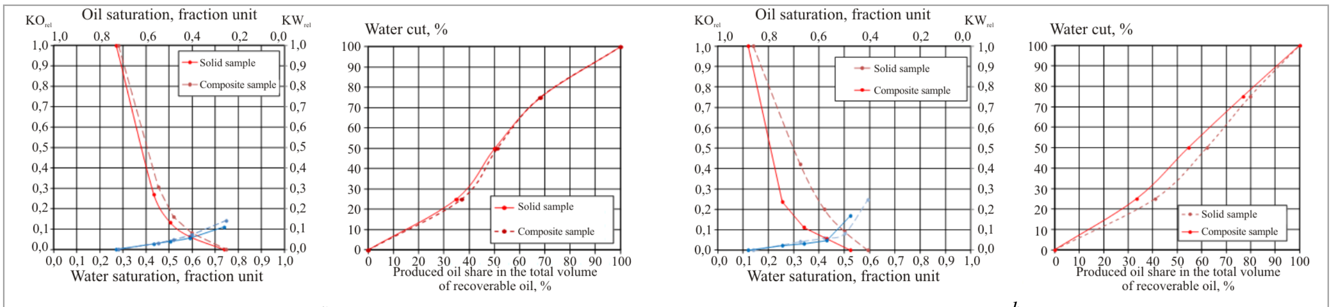


Fig. 5. RPP graphs and dependence of water cut on the displaced volume: *a* – for the terrigenous sample; *b* – for the carbonate sample

The laboratory experiments on the determination of relative phase permeations shown in graphs demonstrate deviations of permeabilities and actual fluid saturations as they relate to the solid and composite samples. The biggest differences are identified in carbonate samples. It further confirms the impact of capillary fractures at the sample butts on the flow and retention of fluids. Should this impact or the end effect defect be considerable, the results of the laboratory tests are deemed to be wrong, which may lead to grave errors in forecasting the stratum operation. Subsequently it is important to consider the manifestation of capillary end effects in filtration tests.

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