A method of modelling phase permeability in the region of a three-phase filtration

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Abstract: The article analyses the models of relative phase permeabilities in the region of a three-phase core saturation. Existing models of relative phase permeabilities in the region of a three-phase core saturation yield a result much rougher than the model described in the works of other authors. The proposed model in this study gives a deviation from the experimental data up to 5%, and the Stone model - up to 70%.

1. Introduction
The verification of the adequacy of the mathematical model of relative phase permeabilities in the three-phase core saturation region implies an experimental determination of permeability values at points with a three-phase core saturation.

The experimental determination of the relative phase permeabilities with a three-phase core saturation still remains an insufficiently studied field of petrophysics. Publications about such studies are few, and their results are ambiguous due to the effect of core drainage [1]. In this paper, we propose a method for obtaining relative core permeabilities in the three-phase saturation region, taking into account the permeability hysteresis as a function of the direction of saturation variation, and an analysis is made of the applicability of various mathematical models for these permeabilities.

2. Research
At present, the main method used to determine the relative phase permeabilities in the region of three-phase core saturation is the method of combined stationary filtration [2]. Despite the fact that the concept of phase permeabilities, laid in the foundations of this method, was formulated for the first time in 1943 and has since been repeatedly confirmed, the physical foundations of this phenomenon are still not fully understood. As a consequence, studies of relative phase permeability in the three-phase core saturation region do not reflect the actual processes occurring in the formation. Below are the arguments in favour of the previous statement.

M. Muskat and others [3] hypothesized that in the simultaneous flow of immiscible liquids in a porous space, two essentially different filtration modes can exist.

In one of these modes, a series of channels of the porous medium remain occupied by the rock wetting fluid, while others are occupied by the fluid immiscible with the first one. Different permeability for the first and second fluids corresponds to different saturations of these fluids, while the fluids in the pores form a continuous flow for each of the filtering phases. It follows from this theoretical assumption that for each of the fluid saturations there is only one permeability for a given fluid. It does not matter which fluid or fluids are filtered together with the studied one, since the interaction between them is assumed only through the fraction of pore of the porous medium occupied
by each of them. They flow, as if each is in its own system of tubes, without interacting with each other.

The concept of the second, slug filtration mode, in which intermittent portions of immiscible fluids move in a porous medium, presupposes a radically different flow pattern, which implies the emulsification of fluids into each other and the filtration of the resulting emulsion. The degree of dispersion of this emulsion depends on the structure and properties of the porous medium and the pressure gradient arising during filtration. So, the higher the hydrodynamic pressure gradient, the more likely the formation of fluid slugs with high capillary pressure gradients, which depends on the size of the slug and the capillary pressures arising on its front and end. When slugs with gradients of capillary pressures above the gradient of hydrodynamic pressure appear, the pore with such a slug ceases largely to be permeable.

Thus, experiments in which processes that actually occur on the objects under study cannot be taken into account and cannot be used to describe them. So, when determining the relative phase permeabilities in the region of three-phase saturation by the method of stationary filtration [2], a three-phase flow of fluids is fed into the core sample and their stationary filtration is expected. However, the fact that in natural conditions this is impossible is ignored. If for two-phase filtration there is no probability that the saturation of the porous medium does not correspond to the displacement process under investigation, for a three-phase flow this is not so. Since in reality, for example, an oil field is developed first in the regime of dissolved gas and then using water flooding, it is necessary to carry out measurements in which oil is displaced first by gas and then by water. The case of joint flow will give very high pressure gradients, which in reality are impossible.

For the same core sample, the relative phase permeabilities for the same saturations will differ during draining and impregnation. If the samples were initially saturated with a wetting fluid, and it is displaced by a nonwetting fluid, then this process is called drainage (for example, the same process occurred during the formation of oil or gas deposits). When draining, filtration of the wetting fluid in small capillaries lags behind the nonwetting fluid in large capillaries, since it is established [6] that, during draining, the nonwetting fluid moves first along the large pores. Therefore, initially, during draining, predominantly separate phase flows are formed which do not substantially affect each other. The relative phase permeabilities for the described process are located more to the right then during impregnation, and the permeability values for the nonwetting fluid are generally higher, at the same saturation values, the reverse situation is observed for the wetting fluid (Figure 1).
Figure 1. Hysteresis of relative phase permeabilities during impregnation and drainage. $S_w$ - saturation with wetting phase, $K_{nw}$ - saturation with nonwetting phase, $K_{rel}$ - relative phase permeability (RPP), $K_{nw \text{(impr)}}$ - RPP for nonwetting phase during impregnation, $K_{w \text{(impr)}}$ - RPP for wetting phase during impregnation, $K_{nw \text{(dr)}}$ - RPC for nonwetting phase during drainage, $K_{w \text{(dr)}}$ - RPP for wetting phase during drainage [6].

The experiments to determine the relative phase permeabilities in the gas-condensate-water system are as follows. At the first stage, the RPP is determined by the method of stationary filtration, with different proportions of water and condensate. Further, on the same core column, oil is displaced with water, pumping 5-10 pore volumes of the displacing agent [5-12].

1. The oil model was a mixture of 64% of the volume fraction of degassed oil in the Urengoy field deposits and 36% of the volume fraction of normal hexane. The proportion in the mixture was selected according to the density of the reservoir oil. As a gas model, chemically pure nitrogen moistened in a gas container with distilled water was used. For the experiments, the oil model was saturated with nitrogen, and after loading into the separator, it was filtered through core samples (selected for preparation of fluids) together with nitrogen. The filtration was carried out under given thermobaric conditions simulating the formation. As a result, gas and oil in the core came to a state of thermodynamic equilibrium, that is, the mass transfer between the fluids and the core became negligible. Then, the viscosity of the fluids was determined by pumping them through the capillaries. Thus, preparation of the fluids for the experiment was completed.

2. Preparation of core samples, creation of residual water saturation on them. Samples were prepared as follows. Samples were cut from the core with a crown 30 mm in diameter. The samples were then extracted in Soxhlet apparatus with an alcohol-benzene mixture prior to extracting all hydrocarbons. The samples were then dried at a temperature of 105 °C. After
that, they were washed from the salts in distilled water and dried again. The samples were then saturated with a model of formation water, mineralized with sodium chloride at a concentration of 12 g/cm³. After saturation of the samples, their electrical resistance and permeability at 100% water saturation were determined to obtain the dependence of resistance on water saturation (first point). To create a residual water saturation, a Jouan KR-25i centrifuge was used. Residual water saturation was determined at a capillary pressure of 0.3 MPa, which corresponds to a rotation speed of 6310 rpm. The sample, previously weighed in a dry state, was completely saturated with a model of formation water and weighed in a saturated state. After that, it was centrifuged for 1 hour at the above-mentioned rotation frequency. After the centrifugation, the sample was weighed again. Then the sample was saturated with kerosene. Subsequently, after all kerosene was replaced by oil, the electrical resistance of the core was determined with the residual water saturation (second point). Two values of the resistance at a certain saturation are sufficient for constructing the dependence of resistance on saturation.

3. Loading the core into the installation.
4. Measurement of the permeability of the core for gas at zero saturation with gas.
5. Injection of 0.2 pore volume of condensate into the core and its distribution by volume of the core sample, pumping gas until the pressure drop stabilizes.
6. Phase permeabilities for gas are obtained by the method of pseudostationary filtration.
7. Gas displacement by condensate, determination of permeability for condensate, with residual gas saturation. Saturation by condensate is determined by the method of material balance.
8. Preparation of core samples with the creation of water saturation, exceeding the previous value by 5%, using the semipermeable membrane in an individual capillaryimeter.
9. Control the immobility of water saturation by pumping gas and determine the electrical resistance of core samples. The electrical resistance of samples during the oil filtration process should not increase.
10. Repeat steps 3-8 until mobile water appears. The mobile water is determined by the growth of electrical resistance.
11. The relative phase permeability for the gas-water system is determined on the same core sample. Based on the results of the determination, a three-phase model of relative phase permeabilities is constructed [4].

Carrying out experiments in this order will allow obtaining the relative phase permeabilities in the gas-condensate-water system and a mathematical model of the relative phase permeabilities in the same system for their mutual comparison.

3. Results and discussion
Based on this, it is required to carry out experiments in such a way that they exactly repeat the processes occurring in the deposits under natural conditions. Thus, for the displacement of oil with gas, water saturation at the same distance from the oil-water contact remains constant. And when approaching the oil-water contact, water saturation increases. Therefore, in order to predict the extraction of gas and oil from wells in the oil and gas condensate field (for example, the Urengoy OGCF), it is necessary to determine the relative phase permeabilities for oil and gas at various stationary saturations by water, that is, using the stationary phase method, where the stationary phase is water.

Thus, the experiments on determining relative phase permeabilities in the gas-oil-water system, when developing an oil and gas condensate field, are as follows.

On the core, the relative phase permeabilities for the oil-water system are measured with residual water saturation. On the same core, the relative phase permeabilities for the oil-gas system are then determined with residual water saturation. The third experiment (on the same core) consisted in determining the relative phase permeabilities for the oil-gas system, with various stationary water saturations (0.167, 0.207, 0.233) created by capillarimetry.
Phase permeabilities in the gas-condensate-water system for three-phase filtration are constructed from the results of the first two experiments in the form of functional (exponential) dependences:

\[ k_{ro} = e^{P_{ow}(S_{ow}-S_{wi}) + E_{ow}(1-S_{ow})} \]

where: \( k_{ro} \) – relative phase permeability for oil, in the oil-gas-water system, fr.unit; \( S_{w} \) – water saturation, fr.unit; \( S_{g} \) – gas saturation, fr.unit; \( S_{wi} \) – residual water saturation, fr.unit; \( E_{ow} \) – exponential coefficient of dependence for the oil-water system; \( P_{ow} \) – power-law coefficient of dependence for the oil-gas system, \( E_{og} \) – exponential coefficient of dependence for the oil-gas system, \( P_{og} \) – power-law coefficient of dependence for the oil-gas system.

According to the method presented above, relative phase permeabilities were determined on the core of the Urengoi OGCF. Experiments were conducted to determine the relative phase permeabilities in the oil-water and oil-gas system for the Urengoy OGCF (Table 1). Based on the measurement results, a functional three-phase model of relative phase permeabilities is constructed, which has the form

\[ k_{ro} = e^{-22.2 \left( \frac{S_{w}}{1-0.13} \right)^{2.126} -20.33 \left( \frac{S_{g}}{1-0.13} \right)^{1.7}} \]

\[ k_{rg} = e^{-88.34 \left( \frac{S_{w}}{1-0.13} \right)^{4.228} -17.06 \left( \frac{S_{g}}{1-0.13} \right)^{4.135}} \]

\[ k_{rw} = 0.741 e^{-5.94 \left( \frac{S_{w}}{1-0.13} \right)^{0.836} -26.31 \left( \frac{S_{g}}{1-0.13} \right)^{2.662}} \]

Table 2 provides a comparison of the results corresponding to the phase permeabilities constructed using the proposed method and the Stone method with the results of experimental determination of the relative phase permeabilities in the oil-gas system for various stationary water saturation.

Table 1. Calculation of the relative permeability model for oil in the three-phase saturation region in the oil-gas-water system.

| Determination of relative phase permeabilities and coefficients \( P_{ow} \) and \( E_{ow} \) in the oil-water system |
|----------------------------------|------------------|------------------|------------------|------------------|
| \( S_{w} \), fr.unit | \( S_{g} \), fr.unit | \( k_{ro} \), fr.unit | \( k_{rg} \), fr.unit | \( k_{rw} \), fr.unit | \( S'_{w} \) | \( K'_{o} \) | \( S'_{g} \) | \( K'_{g} \) |
| 0.130 | 0.870 | 1.000 | 0.000 | -1.844 | -0.844 | 1.631 |
| 0.268 | 0.732 | 0.650 | 0.000 | -1.570 | -0.202 | -0.233 | 1.507 |
| 0.311 | 0.689 | 0.442 | 0.004 | -1.260 | 0.419 | -0.334 | 1.395 |
| 0.377 | 0.623 | 0.219 | 0.008 | -1.033 | 0.902 | -0.440 | 1.280 |
| 0.440 | 0.560 | 0.085 | 0.013 | -0.839 | 1.317 | -0.566 | 1.191 |
| 0.506 | 0.494 | 0.024 | 0.020 | -0.710 | 1.591 | -0.677 | 1.104 |
| 0.558 | 0.442 | 0.007 | 0.028 | -0.596 | 1.831 | -0.801 | 0.979 |
| 0.609 | 0.391 | 0.002 | 0.036 | -0.473 | 2.013 | -0.910 | 0.831 |
| 0.683 | 0.317 | 0.000 | 0.052 | -1.010 | 0.979 | 0.741 |
| 1.000 | 0.000 | 0.000 | 0.741 |

Table 2. Model Parameters.

| Determination of relative phase permeabilities and coefficients \( P_{ow} \) and \( E_{ow} \) in the oil-gas system |
|----------------------------------|------------------|------------------|------------------|------------------|
| \( S_{g} \), fr.unit | \( S_{o} \), fr.unit | \( k_{ro} \), fr.unit | \( k_{rg} \), fr.unit | \( k_{rw} \), fr.unit | \( S'_{g} \) | \( K'_{o} \) | \( S'_{o} \) | \( K'_{g} \) |
| 0.000 | 0.870 | 1.000 | 0.000 | -3.457 | -2.918 | 2.126 |
| 0.027 | 0.843 | 0.947 | 0.000 | -2.550 | -1.192 | -0.081 | 2.472 |
| 0.068 | 0.802 | 0.738 | 0.000 | -2.082 | -0.519 | -0.133 | 2.318 |
| 0.108 | 0.762 | 0.552 | 0.000 | -1.765 | -0.054 | -0.188 | 2.137 |
| 0.149 | 0.721 | 0.388 | 0.000 | -1.525 | 0.336 | -0.246 | 1.914 |
| 0.189 | 0.681 | 0.247 | 0.001 | -1.331 | 0.719 | -0.307 | 1.628 |
| 0.230 | 0.640 | 0.129 | 0.006 | -1.214 | 1.039 | -0.352 | 1.363 |
| 0.258 | 0.612 | 0.059 | 0.020 | -1.124 | 1.039 | -0.352 | 1.363 |
Thus, the existing models of relative phase permeabilities in the region of three-phase core saturation yield a result much rougher than the model described in [4]. The proposed model gives a deviation from the experimental data up to 5%, and the Stone model - up to 70%.

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