The influence of the rocks material composition on the reservoir properties of the reservoir

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Abstract. High oil reserves characterize most fields in Western Siberia. However, along with this, zones of the productive formation that are poorly involved in development and production wells, in which products with a high proportion of water are produced, are distinguished within limits. For understanding the causes of this problem, it is important to consider the material composition of the reservoirs. In particular, it is necessary to consider the clay content, which is associated with the reservoir properties of rocks, hydrophilicity, hydrophobicity and, accordingly, with wettability. The article examined and analyzed a representative sample of core study of two wells in the Gubkinsky oil and gas region, which suggested the possible reasons for the lack of oil reserves.

1. Introduction

The group of BS reservoirs in the Gubkinsky oil and gas region is characterized by the fact that the water cut in the well production is 10-15% ahead of the oil production indicators [1]. The rapid flooding of BS₁₀ strata, often associated with water breakthroughs, is caused by an insufficiently effective system of stimulating the reservoir – the ability of injected water to displace oil from the reservoir. This problem is directly related to the variability of reservoir properties of reservoirs.

In [1, 2], where the relationship between the wettability of kern samples of the BS₁₀ formation and their filtration and capacity properties for one of the fields of the Gubkinsky oil and gas region was considered, a dependence of the wettability type on the content of clay material of kern samples was revealed.
The content of clay particles in the rock has a significant influence on many of its parameters, such as pore composition, diffusion-adsorption activity, radioactivity, filtration and physicochemical properties. It should be noted that the content of clay minerals in the reservoir rock often not only affects its filtration properties [3–8] but also leads to rock hydrophobization. Initially, clays under normal conditions are hydrophilic, and the adsorption of asphaltenes in them is 4.5 times less than in limestones. However, due to the large specific surface of the clay, many asphaltenes can be adsorbed, as a result of which they are hydrophobized [1, 2, 9, 10]. The results of previous studies indicate that hydrophobic group of samples with a low content of clay material and hydrophilic (with high clay content) are the worst in the BS reservoirs. It was concluded that hydrophobization of the slight clay part of the formation occurred during oil migration, while in part of the formation with a high content of clay material. As a result, the strong action of capillary forces, there was no rupture of the water film on the grains of the rock, and the reservoir retained the hydrophilic type of wettability [1, 2, 9].

It is noted that during the operation of the considered field, parts of the BS reservoir that have a hydrophobic type of reservoir demonstrate a rapid increase in water cut. It is assumed that during the water flooding of the reservoir, some of the oil was displaced into zones with a hydrophilic type of wettability, with increased content of clay material.

In this article, we examine the relationship between the clay material content in core samples and their filtration-capacitive properties, as well as a comparison of the obtained dependences with the results of core studies in a neighbouring field to apply the developed approaches to the fields of the oil and gas region under consideration. In this regard, in this work, core samples from two fields were examined – kern samples from wells 335, 364, 673, 685, 1943 and 2011 of the field located in the east (were examined in [1, 2]) and from wells 1712 and 1765 deposits located in the west of the studied oil and gas region. The characteristics of the reservoir properties of kerm samples are shown in Table 1.

### Table 1. Characterization of the studied ker samples

| Well group | Parameter value | Permeability, K, mD | Porosity, m, % | Relative clay content ncl, fractions of units | Wettability parameter, M | Displacement coefficient, Kd, % | The coefficient of residual water saturation, Kres, % |
|------------|----------------|---------------------|---------------|---------------------------------|--------------------------|-------------------------------|---------------------------------|
| 335, 364, | min            | 13.85               | 1             | 14.61                           | 46.63                    | 0.0713                        | 0.07                            |
| 673, 685, | middle         | 19.78               | 184.58        | 30.03                           | 64.13                    | 0.6792                        | 0.18                            |
| 1943, 2011 | max            | 24.24               | 804           | 51.62                           | 81.16                    | 0.9932                        | 0.36                            |
| 1712, 1765 | min            | 2.31                | 0.08          | 20.88                           | 25.87                    | 0.1126                        | 0.01                            |
|            | middle         | 14.07               | 15.65         | 59.49                           | 63.01                    | 0.7094                        | 0.39                            |
|            | max            | 21.54               | 88            | 97.36                           | 97.68                    | 0.9997                        | 0.89                            |

### 2. The results of the study of ker

The property of rock to contain a different mass of dry clay particles is estimated by the specific mass (weight) clay content, the specific volume clay content estimates the content in the rock of a different volume of dry clay particles, and the degree of filling of the intergranular space of the rock with clay material is characterized by relative clay content.

In these studies, the determination of particle size analysis was carried out using the SEDIGRAPH 5000 ET instrument. The method is based on the use of X-rays. The device measures the particle...
deposition rate and automatically gives the results in the form of a percentage distribution in integral form, depending on the equivalent diameters of the sphere (Stokes law). The range of measurement of particle size is from 100 to 0.1 microns.

In the sample studied, the weight clay content varies from 2.2 to 23.48%. The character of the distribution of relative clay content has a rather wide range of changes from 0.1 to 0.89, i.e. covers almost the entire possible interval of its change. In other words, clay particles can occupy almost the entire volume of intergranular space.

Table 2 shows the correlation coefficients for the entire sample volume of the filtration-capacitive properties and clay content of core samples. Table 3 shows the correlation coefficients of the dependence of the values of filtration-capacitive properties and clay content on the size of pores and particles of core samples.

As can be seen from Table 2, between the values of porosity $m$ and permeability $K$, there is a negative correlation with clay values, first of all, with the relative clay content. With the clay weight, the correlation is less pronounced. Also according to Table 2, there is a correlation of porosity with the size of pores and particles composing core samples – a negative correlation with particles less than 50 μm and pores less than 1 μm, positive – with particles more than 250 μm, pores more than 5 μm.

Table 2. Correlation diagram for the filtration-capacitive properties of kern and clay samples

| Filtration and Capacitive Parameters of Kern Samples | Porosity, $m$, % | Permeability, $K$, mD | The coefficient of residual water saturation, $K_{res}$, % | Displacement coefficient, $K_d$, % | Wettability parameter, $M$ | Weight clay, $C_{cl}$, % | Relative clay, $n_{cl}$, fractions of units |
|---------------------------------------------------|------------------|----------------------|------------------------|------------------|-----------------|------------------|-----------------------------|
| Porosity, $m$, %                                   | 1                |                      |                        |                  |                 |                  |                             |
| Permeability, $K$, mD                              | 0.5910           | 1                    |                        |                  |                 |                  |                             |
| The coefficient of residual water saturation, $K_{res}$, % | -0.8627          | -0.5170              | 1                      |                  |                 |                  |                             |
| Displacement coefficient, $K_d$, %                 | 0.5170           | 0.3135               | -0.4390                | 1                |                 |                  |                             |
| Wettability parameter, $M$                         | -0.5725          | -0.5549              | 0.5732                 | -0.5575          | 1               |                  |                             |
| Weight clay, $C_{cl}$, %                           | -0.7435          | -0.4821              | 0.6943                 | -0.4325          | 0.4220          | 1                |                             |
| Relative clay, $n_{cl}$, fractions of units        | -0.8955          | -0.5170              | 0.8062                 | -0.5243          | 0.5138          | 0.9502           | 1                           |

Figure 1 shows that the dependence of the porosity of the samples on the relative clay content is linear in the entire range of possible clay contents. It should be noted that the values in Figure 1 were distributed according to the type of wettability as follows: a region with porosity values above 19% and a relative clay content of 0.12 units refers to a purely hydrophobic type of wettability (the “region” of values highlighted by light gray); an area with porosity values less than 14.5 and relative clay content more than 0.38 units – purely hydrophilic (“region” of values highlighted in dark gray). A group of samples with a heterogeneous type of wettability is located between the regions mentioned above, the intersection of the upper and lower regions. Thus, the dependence of an increase in the
parameter $M$ with an increase in the clay content of the samples and a decrease in their porosity is traced. The area between them contains points with both hydrophobic and hydrophilic wettability.

Table 3. Correlation diagram of the dependences of the reservoir properties of core samples on the content of clay material in them

| Parameter                                           | 1-2 | 2-5 | 5-10 | >10 |
|-----------------------------------------------------|-----|-----|------|-----|
| Pore size distribution, % vol.                      |     |     |      |     |
| Wettability parameter, $M$                          | -0.6892 | 0.1614 | 0.1279 | 0.5313 | 0.6110 |
| Permeability, $K$, mD                               | -0.3750 | -0.1717 | -0.2638 | 0.3664 | 0.7706 |
| The coefficient of residual water saturation, $K_{\text{res}}$, % | 0.7173 | -0.2370 | -0.1974 | -0.6054 | -0.4889 |
| Displacement coefficient, $K_{d}$, %                | -0.5683 | 0.1423 | 0.4299 | 0.1856 | 0.3086 |
| Weight clay, $C_{cl}$, %                            | 0.6197 | -0.2600 | -0.1963 | -0.5010 | -0.4732 |
| Relative clay, $n_{cl}$, fractions of units         | 0.6961 | -0.2933 | -0.2666 | -0.5326 | -0.4927 |

Figure 1. The dependence of the distribution of porosity $m$ on relative clay, $n_{cl}$
The value of the correlation coefficient of permeability $K$ with relative clay content is lower than that of porosity (Table 2). According to the distribution of points (Figure 2), the permeability of the samples also depends on the content of clay material in them. In this case, dependence has the form of a power function. The scatter of points relative to the approximating function is higher than in Figure 2, which leads to a decrease in the correlation coefficient (Table 2).

Permeability values have a weak negative correlation with pore sizes of less than 5 $\mu$m, a significant value of the positive correlation coefficient is observed in samples with pores of more than 10 $\mu$m (Table 3). A significant correlation in permeability is observed with the sizes of particles composing core samples by particles – positive with particles greater than 250 microns, negative – with particles less than 100 microns.

Also, as in the case of the porosity – relative clay content dependence (Figure 2), a similar distribution of points by wettability type is observed: at values of permeability above 0.1 $\mu$m$^2$, there are points to which the hydrophobic type of wettability corresponds, below 0.01 $\mu$m$^2$ – hydrophilic.

The range of relative clay contents is similar to the porosity – relative clay ratio.

The values of the residual water saturation coefficient $K_{rws}$ of core samples increase with increasing content of clay material, small pores (less than 1 $\mu$m) and particles (less than 50 $\mu$m) in them. A significant negative correlation is observed with large, more than 5 $\mu$m pores, and particles of more than 250 $\mu$m (Tables 2 and 3). The dependence of the residual water saturation on the relative clay content is described by a function of the sigmoid type (Figure 3). The hydrophobic group of samples is located below the $K_{rws} = 25\%$, the hydrophilic group at $K_{rws}$ above 45\%.

![Figure 2. The dependence of the distribution of permeability $K$ on relative clay, $n_{cl}$](image-url)
Figure 3. The dependence of the distribution of residual water saturation $K_{rws}$ on relative clay, $n_{cl}$

A single equation describes the dependences of the values of porosity, permeability, and residual water saturation of core samples on the content of clay material in them for both considered deposits. At the same time, the core samples of the western field contain more clay material and have worse reservoir properties (Table 1), located mainly on the right side of the graphs with lower values of porosity, permeability and greater residual water saturation (Figures 1-3).

This result is because, during the formation of BS group strata, the source of debris material fragmentation was located on the eastern side relative to the studied deposits. Consequently, the territory of the eastern deposit was located in an area with a shallower depth of the sea and a more intense hydrodynamic situation, which contributed to the accumulation of larger precipitation, in comparison with the western deposit.

Various functions describe the dependences of the displacement coefficient ($K_d$) and the wettability parameter (M) on the relative clay content (Figures 4 and 6) (in Figures 4 and 6, the approximating curve indicated by a solid line is constructed according to the data of well group 335, 364, 673, 685, 1943 and 2011, dashed – according to the group of wells 1712 and 1765) but at the same time maintaining the general patterns of distribution of points.

The spread and average values of the parameter M are almost identical for both considered groups of wells. It should also be noted that the values of the displacement coefficient for the group of wells of the western field are characterized by a widespread relative to the average value than in the group of wells of the eastern field. In contrast, the average $K_d$ values for both groups of wells practically coincide (Table 1). The dependence of the displacement coefficient on the relative clay content of the samples, taking into account the type of wettability, is shown in Figure 5.
Figure 4. The dependence of the distribution of the values of the displacement coefficient $K_d$ relative to clay, $n_{cl}$.

Figure 5. The dependence of the distribution of the displacement coefficient $K_d$ on the relative clay $n_{cl}$ by the type of wettability.
Figure 6. The dependence of the distribution of the wettability parameter M on the relative clay content, $n_{cl}$

According to the distribution of points in this figure, it can be observed that the hydrophobic group of the samples has a more significant mean displacement coefficient of 74.6%, with a lower standard deviation of 6.4, the hydrophilic group has an average $K_d$ of 55.5%, and with a standard deviation of 15.9. An exception is a group of samples with numbers 9, 20, 37, and 38 for wells 1712 and 1765, which have hydrophilic wettability and high values of displacement coefficient, on average for this group of samples – 87.5%. In this case, samples of groups with a hydrophobic and hydrophilic type of wettability practically do not mix, samples with a different type of wettability act as the boundary between the hydrophobic and hydrophilic groups.

3. Analysis of the results

An analysis of the obtained regression dependences of the clay content change on the porosity and permeability of core samples showed that the content of clay material decreases with an increase in porosity and permeability of the samples. The porosity values have a good close relationship with the relative clay content of the samples over the entire range of its change; the spread of permeability values relative to the established dependence increases with decreasing clay content of the samples. The obtained dependences of the porosity and permeability of the samples on the relative clay content are valid for the entire sample under study. Since kern samples from two fields represent the sample, it can be assumed that these dependencies are applicable for most of the oil and gas region. This assumption is also valid for the dependence of the coefficient of residual water saturation on relative clay content.

An analysis of the dependences of clay content on the permeability of samples shows that the most significant change in clay content (from 0.24 to 0.9 units) is observed in low-permeability samples (less than 0.008 $\mu$m$^2$). A further increase in permeability leads to stabilization of clay content. For samples with a permeability of more than 0.010 $\mu$m$^2$, clay content varies from 0.06 to 0.35 units. This result can be explained by the fact that relative clay content is a complex parameter, i.e. in addition to
the clayey weight, the porosity of the samples is taken into account in its calculation.

The hydrophobic group of samples has the highest average values of the displacement coefficient, with the increase in clay content, the hydrophobization of the samples increases and the value of $K_d$ decreases. Moreover, the most significant change in the displacement coefficient is observed in the regions of hydrophobic groups in the ranges of relative clay content – for wells in the eastern field from 0.04 to 0.24 units, for the group of wells in the western field from 0.16 to 0.46 units. Above these values, a change in clay content has little effect on a change in the displacement coefficient.

A similar dependence of the decrease in the displacement coefficient with increasing hydrophilicity of the samples is explained by the fact that the hydrophobic group is composed of larger particles and, accordingly, has larger pores containing a larger volume of mobile oil that can be displaced by water. With an increase in the content of clay material, the pore size decreases, which, despite the increase in hydrophilicity, leads to an increase in the action of capillary forces that impede the displacement of oil.

When analyzing these dependencies, taking into account the type of wettability of the samples, the hydrophobic group has better reservoir properties than the hydrophilic group, which is also true for both considered deposits. According to [11], if the reservoir was initially hydrophilic, then during migration, oil occupies large pores and water occupies small pores. With such a development of events, according to the conclusions of [1, 2], oil, occupying large pores, changes their wettability to hydrophobic, and regions of heterogeneous wettability are formed in smaller pores. The smallest pores remain water-saturated due to the intense action of capillary forces, as well as the too-small size of the pore channels into which oil cannot penetrate [11, 12].

Thus, it can be assumed that the saturation boundaries pass along the upper wettability boundary of the heterogeneous group of samples (Figure 6), which corresponds to the values of porosity 12%, permeability 0.001 μm$^2$ and related clay content of 0.42 units. As confirmation, we can consider the distribution of points in Figure 5, where a group of samples with a different type of wettability separates the hydrophobic and hydrophilic groups.

When the reservoir is flooded, the pressure of the aqueous phase exceeds the pressure of the oil. At the same time, part of the oil is displaced along with large and medium pores to the producing wells, and part is displaced in the region of small pores and with a high content of clay material, increasing areas with heterogeneous wettability. When water breaks through to production wells, drainage channels are created in this case, which mainly includes areas with large pores, since the pressure gradient, in this case, is minimal according to the Darcy-Weisbach equation for laminar flow in pores with rigid walls:

$$\Delta P = \frac{32L\nu^2\rho}{ReD},$$

where $L$ is the pore length; $D$ is the pore diameter; $\nu$ is the flow rate; $\rho$ is the fluid density; $Re$ is the Reynolds number equal to:

$$Re = \frac{\rho\nu D}{\eta},$$

where $\eta$ is the dynamic viscosity of the fluid.

Thus, the pressure drop between the injection and production wells is inversely proportional to the square of the pore diameter and directly proportional to the viscosity of the fluid. Since the viscosity of the oil at 50 °C is from 1.6 to 7.1 mm$^2$/s, and that of water at the same temperature is about 0.6 mm$^2$/s, under medium and small pores, non-draining regions containing residual oil reserves can be formed.

4. Conclusion

The nature of the dependence of porosity, permeability, and residual water saturation on the clay material content in kern samples for the two fields of the Gubkinsky oil and gas region is the same. It
can be assumed that the obtained dependences of the filtration-capacity properties on clay content are applicable for BS10 formations of deposits located close to the oil and gas considered region. The dependences of the displacement coefficient and the wettability parameter on the content of clay material are individual for each field.

During waterflooding during the development of deposits in this oil and gas region, part of the oil could be displaced from large pores in the region of small pores with low filtration and high clay content. When the injected water breaks through to the production wells through large pore systems in the low-permeability areas of the reservoirs, non-drained areas are formed in which residual oil may be contained.

The results obtained make it possible to identify areas of a low-permeability reservoir with a heterogeneous or hydrophilic type of wettability containing fixed residual oil reserves that can be extracted by optimizing the waterflooding system.

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