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Analysis of Hydrocarbon Saturation Nature in a Heterogeneous Reservoir as Exemplified in AC10 Formation of Priobskoe Field

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Abstract: The main factors affecting the nature of uneven hydrocarbon saturation of the AC10 formation reservoir at Priobskoye field located in Western Siberia are considered. The formation is characterized by extreme heterogeneity caused by macro- and microstructure, which is determined by the lithofacial and structural-morphological conditions of sedimentation. The formation is characterized by high variability of lithological-mineralogical composition and textural and structural features. To bring to light the nature of the uneven hydrocarbon saturation of the reservoir, the combined analysis of the findings obtained from the study of the size of capillary channels and pores, as well as the investigation of the degree of their filling with clay and carbonate material, was performed. The analysis has shown that the filler composition, its amount in the pore space, and the (core) hydrocarbon saturation collectively evened the AC10 formation electrical resistance in different saturation zones, which led to distortion of the hydrocarbon saturation of the reservoir as a whole.

Keywords: heterogeneity, hydrocarbon saturation, pore and pore channel sizes, porosity, permeability, clayiness, carbonate content.

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Анализ характера насыщенности пород в неоднородном коллекторе на примере пласта АС10 Приобского месторождения

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Аннотация: Рассматриваются основные факторы, оказывающие влияние на природу неравномерной насыщенности углеводородами (УВ) коллектора пласта АС10 Приобского месторождения, расположенного на территории Западной Сибири. Отложения залежи характеризуются чрезвычайной неоднородностью, обусловленной макро- и микростроением, которое определено литолого-фациальными и структурно-морфологическими условиями осадконакопления. Данная залежь отличается широкой изменчивостью литолого-минералогического состава и текстурно-структурных особенностей. С целью выявления природы неравномерной насыщенности коллектора УВ выполнен совместный анализ результатов, полученных по размерам капиллярных каналов и пор, а также степени их заполнения глинистым и карбонатным материалом. Исследования показали, что состав цемента, его количество в поровом пространстве и насыщенность керна УВ в совокупности нивелировали электрическое сопротивление пласта АС10 в различных зонах насыщения, что привело к искажению насыщенности коллектора в целом.

Ключевые слова: неоднородность, насыщенность, размеры пор и поровых каналов, пористость, проницаемость, глинистость, карбонатность.

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Introduction

Rock heterogeneity is a fundamental property of matter. M.V. Rats noted that heterogeneity is inherent in any rock from the moment of its origination and disappears only with the disappearance of the rock itself. The problem of heterogeneity of rocks and the variability of their physical properties at different levels of the material structural organization and under various thermodynamic conditions is fundamental in petrophysics [13]. G. I. Petkevich emphasized that when describing heterogeneous and different-scale geological objects, there is an urgent need for new approaches, improvement of concepts and terms, the introduction of formal constructs and quantitative indicators.

The heterogeneity attracts the attention of geologists of all specializations (including petrophysicists) since the inception of geological sciences. Most researchers studying the petrographic, lithological, hydrodynamic and other features of rocks, in fact, are engaged in nothing more than the study of heterogeneity of rocks. Geophysicists are not the exception.

One of the important properties of the geological environment (GE) is its time-to-time and spatial variability. Variability determines the heterogeneity of an object, which is determined by the difference in its properties at different points. Modern modeling in geological sciences imposes strict requirements on the study and obtaining of source information. First of all, this is a detailed description of thin layers and microlayers of a rock and quantitative assessment of all the required parameters of these layers. The parameters studied at individual point in the GE do not always suit specialists. In laboratory practice, the study of rock properties is carried out precisely based on a point-to-point discrete principle, although it is far from always possible to select samples for analysis from a thin layer.

It was repeatedly noted in [14, 15, 18–20] that, in essence, all petrophysical characters are of the inherited character of lithofacial variability. This is due to the heterogeneity formed during the diagenesis of sedimentary rocks that occur at different points in the GE in different ways (under different conditions). As a result, the further course of epigenesis is “superimposed” on the diagenesis process. Hence the heredity of the heterogeneity of rocks arises, which determines the variability of petrophysical (and not only) features.

At present, the study of rock heterogeneity in petroleum geology is becoming increasingly important, since the main reserves of oil and gas are accumulated in reservoirs with low permeability (poroperm properties or reservoir quality (RQ)), complicated by structural heterogeneity. Along with resolving issues of the methodology, the influence of heterogeneity of reservoir rocks on the reservoir properties, the rock permeability, hydrocarbon saturation, and displacement efficiency is studied. The pictures of the movement of oil-water contact, ways to increase oil recovery are also studied – all these issues are very important for successful development of a field. When assessing the mentioned parameters of reservoir rocks, description and analysis of heterogeneity are of crucial importance. A number of researchers [1–3, 5, 8] have done a great job of analysis and assessment of geological heterogeneity in the design of oil field development. However, in theory and practical aspects of hydrocarbon reserve estimation, this issue remains less studied and is only limited to determining the factors characterizing heterogeneity, and typifying oil deposits based on them [5, 9]. Attention should also be paid to the ambiguous interpretation of the concepts of "geological heterogeneity" and "confidence of oil and gas reserves" [1, 5, 7, 9; 21–23].

The influence of heterogeneity on sediment productivity was noted by many experts [4, 9, 13, 26–28]. It has been established that increasing the degree of heterogeneity of reservoir rocks leads to decreasing productivity. In petroleum geology, micro- and macro-heterogeneity is usually distinguished [6, 7, 10, 21].

Micro-heterogeneity of rocks is studied, as a rule, in laboratory conditions by traditional methods: in thin sections, on images of a scanning electron microscope, by capillarimetry, X-ray phase analysis, and acoustic measurements, as well as using devices designed to determine effective porosity and permeability coefficient. These are the basic methods. There are also special ones: immersion, thermal, X-ray fluorescence, IR spectrometric, and other methods of analysis.

To study macro-heterogeneity, geophysical well logging data for all drilled wells and seismic data are used. Macro-heterogeneity is studied vertically (along the thickness of a horizon) and along the strike of the formations (by area).

Geologists (geophysicists) pay special attention to macro-heterogeneity with a detailed breakdown of reservoir horizons by impermeable sublayers.

The aim of this work is an attempt to identify the nature of uneven hydrocarbon saturation of the AC10 formation reservoir and the impact of heterogeneity on the rock physical properties.

The findings discussion

Analysis of hydrocarbon saturation nature the AC10 formation rocks was performed based on two boreholes of the Priobskoe field.

In the process of the AC10 formation origination, the sea basin was sharply differentiated in depth. This was due to its partial shallowing in the eastern and southeastern parts of the region due to the accumulation of significant masses of terrigenous material. The edge of the shelf was located within the considered territory. The amount of fragmental product entering the basin increased. The formation of sand bodies during this period was connected both with the accumulation of the fragmental product in the shelf area, especially in its frontal part, and with the activity of turbidite flows of various hydrodynamic activity. The sand strata of various genesis may be spatially separated, connected by "channels" or represent a single body. The conditions of sedimentation determined the rather intricate spatial (in plan view and cross-section) nature of the distribution of the sand bodies.

The area of the sand body occurrence in the lower part of the AC10 formation belongs to the shelf zone, which was very flat and apparently represented an alluvial-delta plain. The inflow of material occurred from the southeast through two channels with its redistribution along the frontal zone. The sea basin in the period under review retained differentiation in depth. At the stage of completion of the AC10 formation origination, the differentiation of the sea basin in depth successively decreased that was connected with the accumulation of terrigenous material in the previous time. The amount of the fragmental product supplied decreased, and basin processes began to prevail in its redistribution, under the influence of which bar systems were formed. The activity of turbidite flows is observed only in the western part of the area, confined to the slope and lower part of the terrain.

It becomes clear from the foregoing that the conditions of the AC10 formation origination suggest wide variability of its lithological and mineralogical composition and textural-and-structural features.

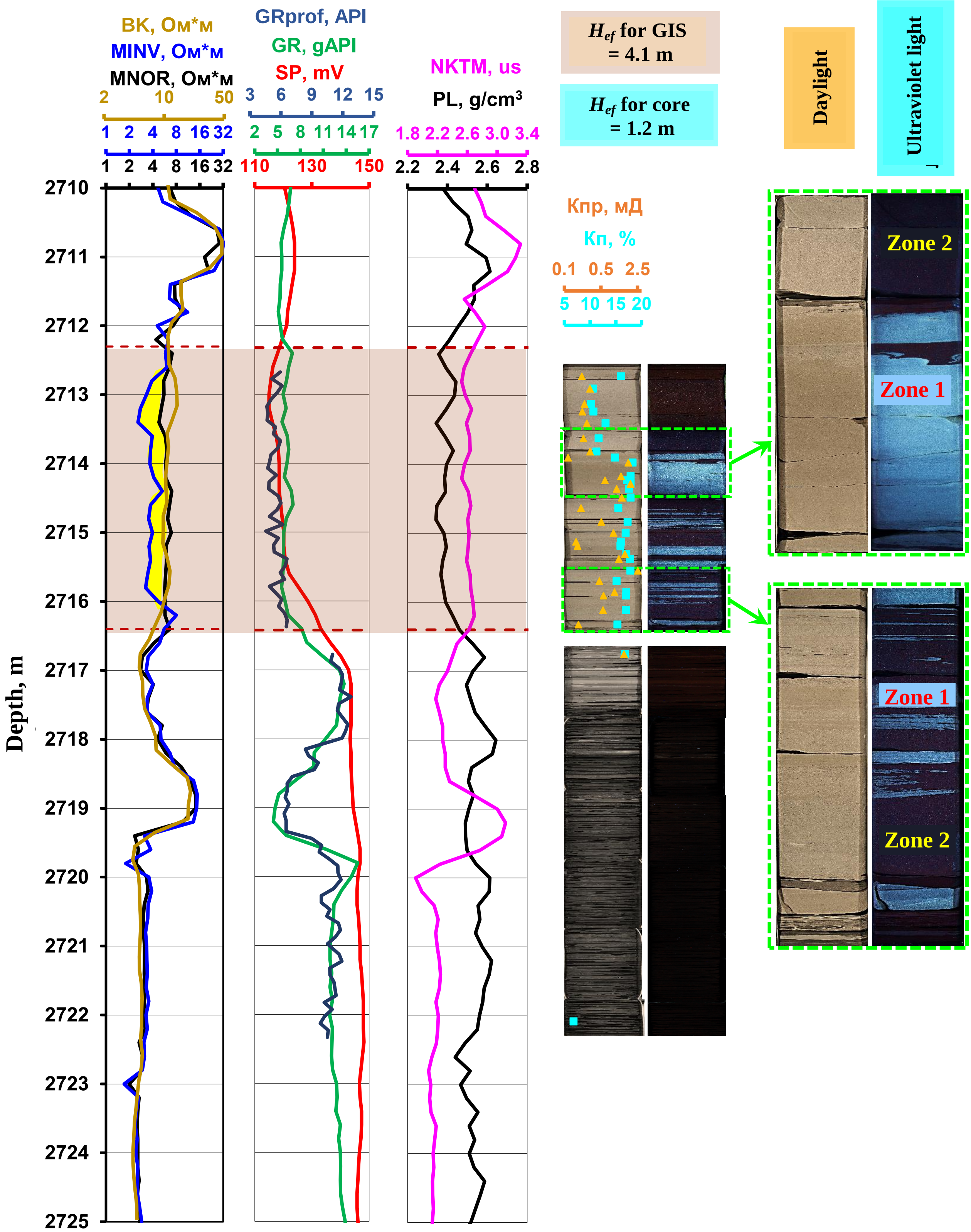


Fig. 1. Geophysical logging data and core photographs in daylight and ultraviolet light for the rocks of AC10 formation in borehole 1 at Priobskoe field

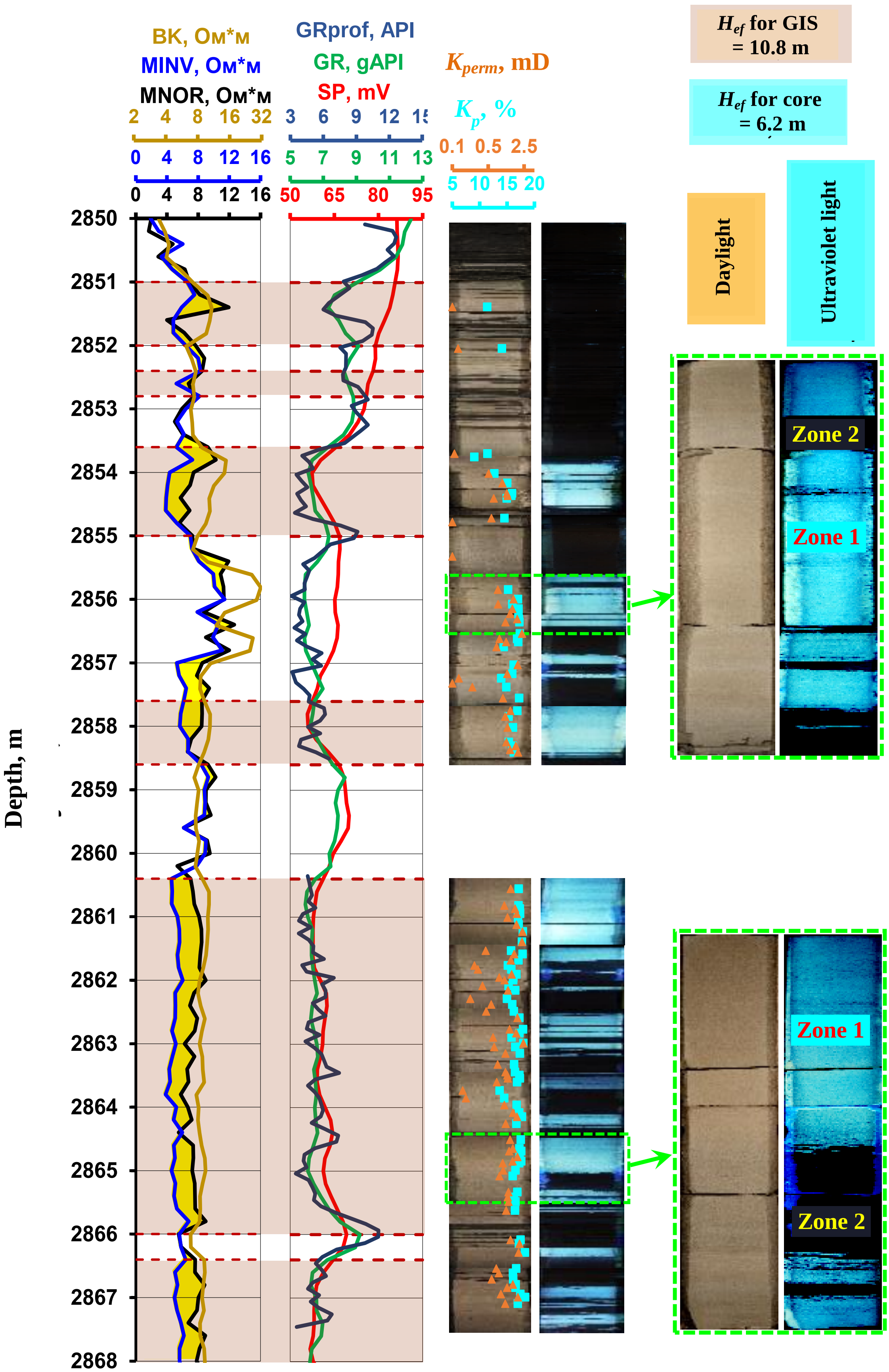


Fig. 2. Geophysical logging data and core photographs in daylight and ultraviolet light for the rocks of AC10 formation in borehole 2 at Priobskoe field

Fig. 1 and 2 show the comparison of the geophysical well logging data with core photographs in daylight and ultraviolet light for the rocks of the AC10 formation from two boreholes at the Priobskoe field. In the given intervals of depth, the total effective thickness H_{ef} determined by the logging data was 14.9 m, whereas from the core photographs in ultraviolet (UV) light H_{ef} of the oil-saturated interlayers is 7.4 m only, i.e. by 50.0 % less. It can be seen in the photographs in daylight that the core of the AC10 formation is predominantly homogeneous. However, the photographs in ultraviolet light showed island core saturation with hydrocarbons. In the photograph in UV light, 2 zones are clearly distinguished: bright glowing (zone 1) and dark glowing (zone 2).

Let's try to comprehend why the core visually homogenous in photographs in daylight, shows island core saturation with hydrocarbons in the photographs in UV light.

Lithologically, the rocks of zone 1 are represented by sandstone and siltstone with clay and carbonate-clay cement, and those of zone 2 are siltstone with clay and carbonate cement (Fig. 3).

For the rocks of zone 1, the sand fraction amounts to from 40.4 to 59.2% (the average value is 44.6 %), the silt fraction amounts to from 33.2 to 49.2 % (45.0 %), and the clay fraction, from 7.3 up to 12.7 % (10.3 %); the carbonate content varies within 2.5–9.6% (4.9 %).

For the rocks of zone 2, the sand fraction amounts to from 23.6 to 47.9 % (the average value is 35.4 %), the silt fraction amounts to 38.7 to 59.6 % (50.4 %), and the clay fraction, from 10.5 up to 24.1 % (14.2 %), the carbonate content varies within 4.6–30.9 % (9.3 %) (Fig. 4).

The rocks of zone 1 and zone 2 are of poor grading (Fig. 5). The grading factor is often used as an indicator of sedimentation conditions. However, in most cases, it gives only comparative characteristics.

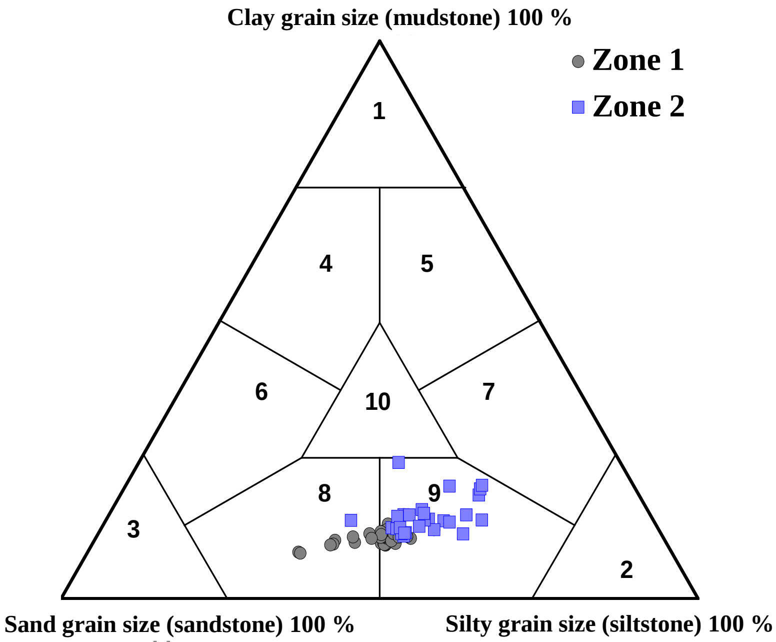


Fig. 3. Classification graphic chart of sandy-silty-clay rocks according to F. Shepard [12]:
1 – mudstone; *2* – siltstone; *3* – sandstone; *4* – sandy mudstone; *5* – silty mudstone; *6* – clayey sandstone; *7* – clayey siltstone; *8* – silty sandstone; *9* – sandy siltstone; *10* – sandy-silty mudstone

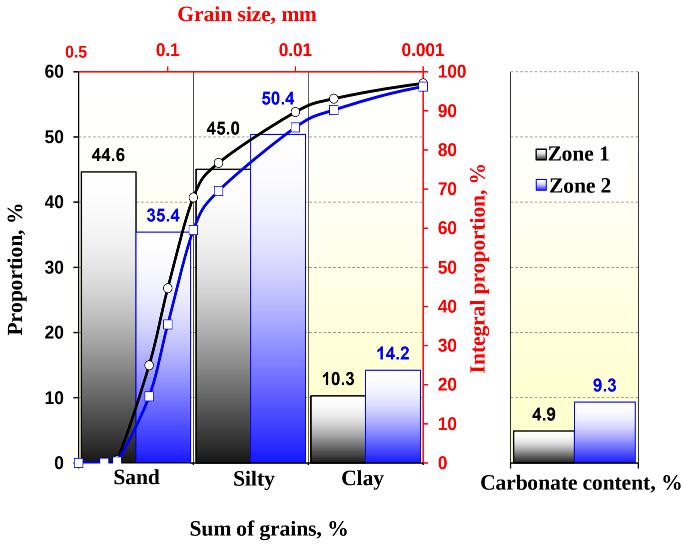


Fig. 4. Grain-size and carbonate content distribution in rocks of AC10 formation of Priobskoe field

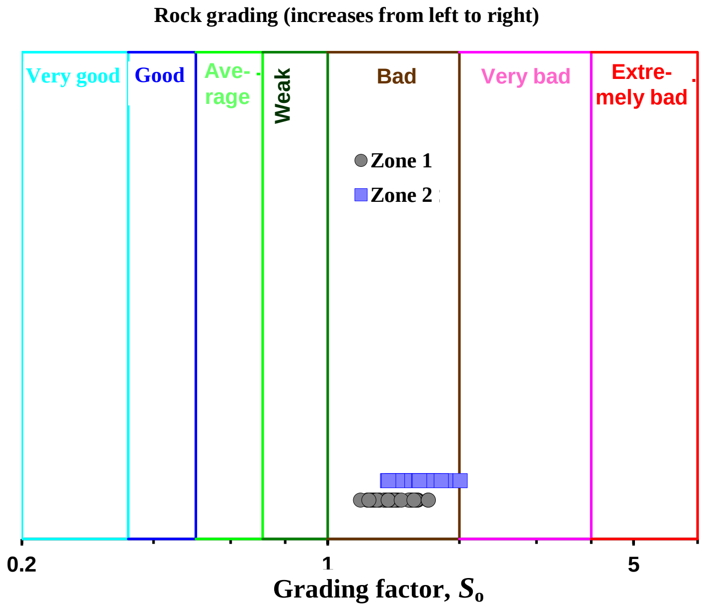


Fig. 5. Sorting of the AC10 formation rocks according to R.L. Folk and W.C. Ward [24]

The clastic rock grain size distribution has a certain genetic significance, since it reflects the nature of transportation and the dynamics of sedimentation medium. Paired combinations of grain size factors are used to compile “genetic diagrams” that reflect, with varying degree of confidence, the dynamic conditions of the sedimentation medium. The most famous diagrams are those of R. Passsega and G.F. Rozhkov.

Dynamic diagram developed by R. Passsega involves such characteristics as median grain size *M* and grain size/centile *S*, µm, reflecting the maximum flow capacity. This takes into account the way of transporting the fragmental product by particle rolling, saltation, transfer in the form of a graded or homogeneous suspension. Dynamic genetic diagram by G.F. Rozhkov is based on the principle of natural mechanical differentiation of particles of sand and silt size (aeolian processes are also taken into account). The diagram is based on the asymmetry and excess relationships, which are determined by the statistical moment formulas [11].

According to the diagrams by R. Passsega and G.F. Rozhkov, the AC10 formation sediments mainly correspond to the type of suspension sediment type and, to a lesser extent, to the type of rolling sediment of the littoral facies complex (Fig. 6, 7).

Based on the analysis of porosity and permeability, the rocks of the selected zones belong to different petrophysical types (Fig. 8). The estimation of the pore space in thin sections showed that the rocks of zone 1 have larger pores relative to the rocks of zone 2 (Fig. 9).

To bring to light the nature of the uneven hydrocarbon saturation of the reservoir in the distinguished zones, the combined analysis of the findings obtained from the study of the size of capillary channels and pores, as well as the investigation of the degree of their filling with clay and carbonate material, was performed.

The sizes of pores and pore channels and the nature of their distribution in size are one of the important indicators in petrophysics. The distribution of phases in the reservoir largely depends on these indicators. The petrophysical parameters mainly depend on the size of the pore channels composing the pore space. It is known that the more heterogeneous the sizes of the reservoir pore channels, the greater the residual hydrocarbon saturation and the lower the displacement efficiency. This phenomenon in mudded-off reservoirs is primarily due to the Laplace effect [16].

With the aim of studying the structural features of the pore space in the distinguished zones, an analysis of scanning electron microscope (SEM) images was performed (Fig. 10). In the rocks of zone 1, predominance of inter-microaggregate-grain, inter-grain and intra-grain micropores, as well as cavernous-expanded leaching pores with average size of 14 μm, very few pores with cross-section of up to 70 μm, anisometric and slot-shaped, connecting with each other through ultracapillary and narrow slot-like pore channels is observed.

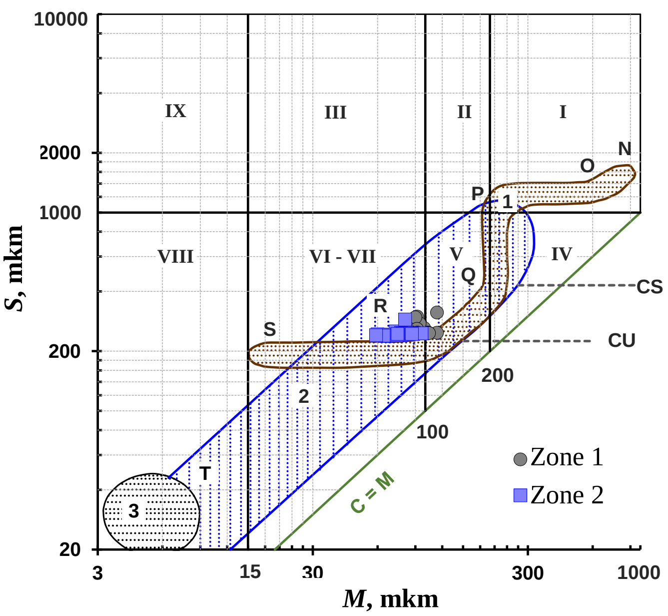


Fig. 6. Genetic S-M diagram by R. Passega [25]

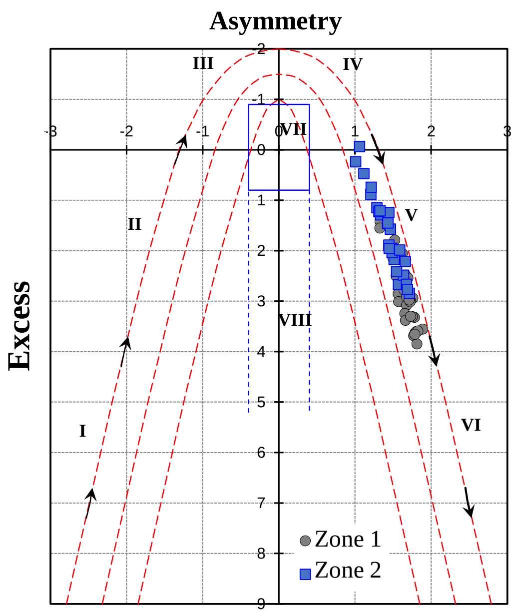
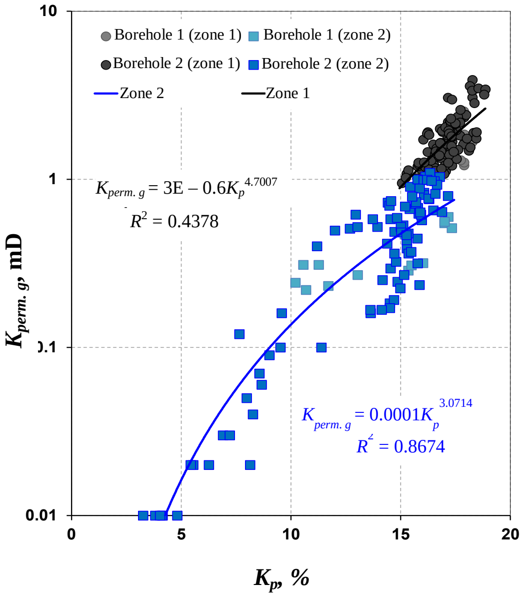


Fig. 7. Dynamic genetic diagram by G.F. Rozhkov [17]



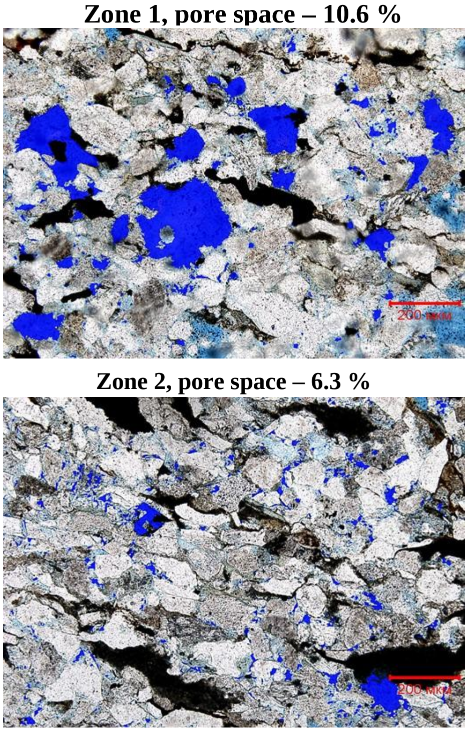
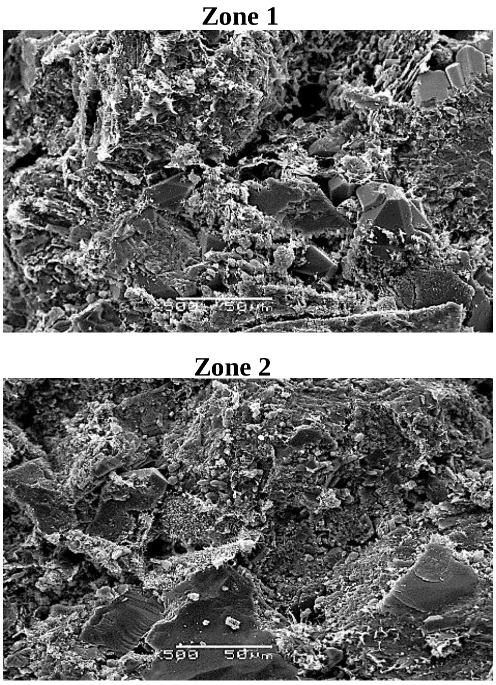


Fig. 8. Comparison of absolute permeability for gas ($K_{perm.\,g}$) with open porosity (K_p)

Fig. 9. Calculation of pore space using thin section photographs in transmitted light with "mask overlay"



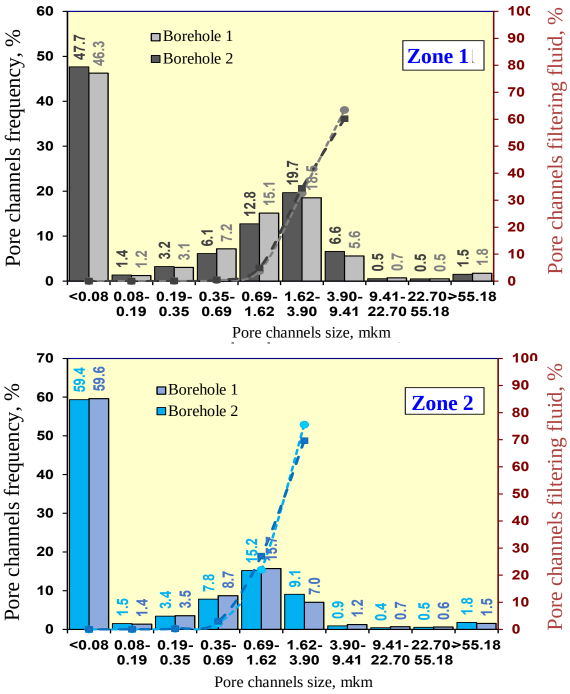


Fig. 10. Electron-scan microscope image photographs General rock texture and the pore space structure features, zooming of 500x

Fig. 11. Distribution of pore channels by size and their participation in oil filtration

In the rocks of zone 2, predominance of inter-grain and inter-microaggregate-grain micropores, more rarely intra-grain micropores, with average size of 8 μm, very few pores with cross-section of up to 20 μm, anisometric and sinuous-slot-shaped, closed and connecting with each other through ultracapillary pore channels is observed.

The study of the pore space structure by centrifugation revealed that in the rocks of zone 1, pore channels from 1.62 to 3.90 μm in size prevail, and the main role in liquid filtration is played by pore channels of size from 3.90 to 9.41 μm, while in the rocks of zone 2, pore channels from 0.69 to 1.62 μm in size predominate, and liquid filtration mainly occurs through pore channels of size from 1.62 to 3.90 μm (Fig. 11).

The analysis of the pore space structural features revealed that the rocks of zone 1 have larger pores and have better filtration channels (pore throats) relative to the rocks of zone 2.

Based on the data on the distribution of the pore channels and their participation in the liquid filtration, the average radii of the pore channels were calculated by the method of statistical moments, and their comparison with the absolute gas permeability was performed (Fig. 12). The statistical moment method is based on the rigorous probabilistic theory of estimating statistical characteristics [16].

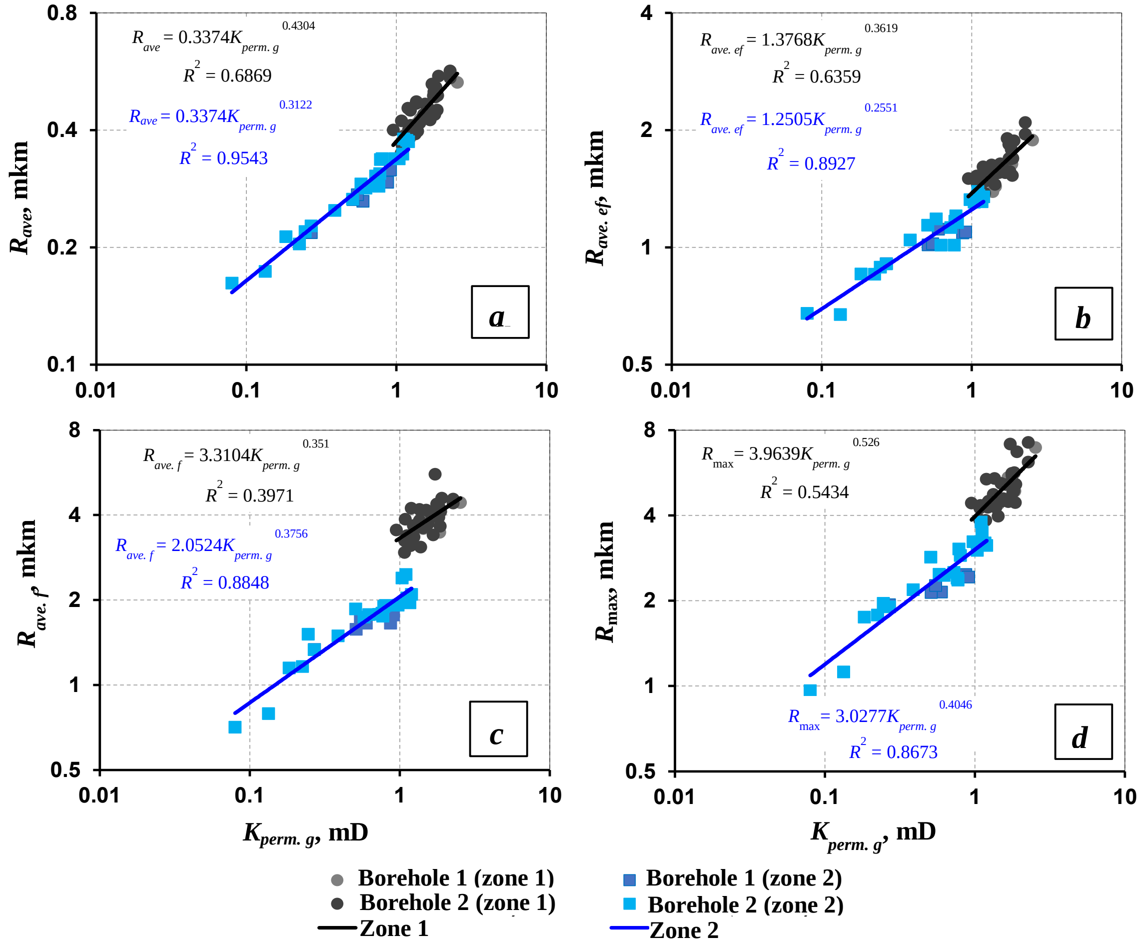


Fig. 12. **Average (R_{ave}) (*a*), average effective ($R_{ave.\,ef}$) (*b*), average filtering ($R_{ave.\,f}$) (*c*), and maximum (R_{max}) (*d*) radii of the pore channels versus absolute permeability for gas ($K_{perm.\,g}$)**

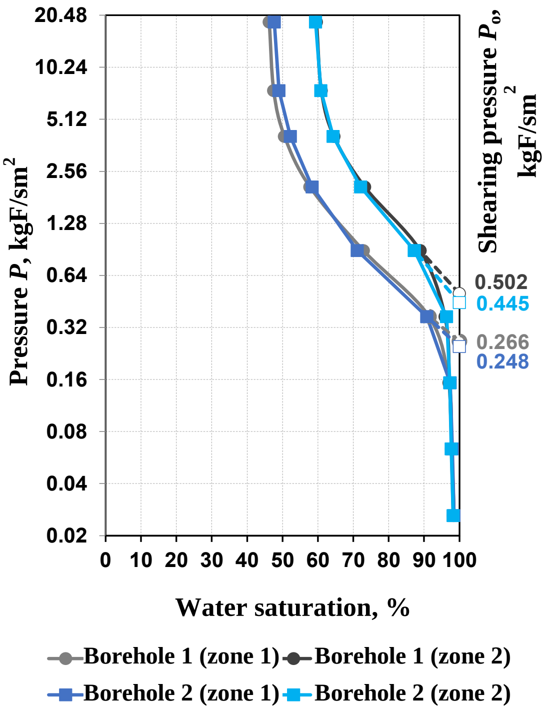


Fig. 13. Graphic determination of shearing pressure (P_o) for selected zones

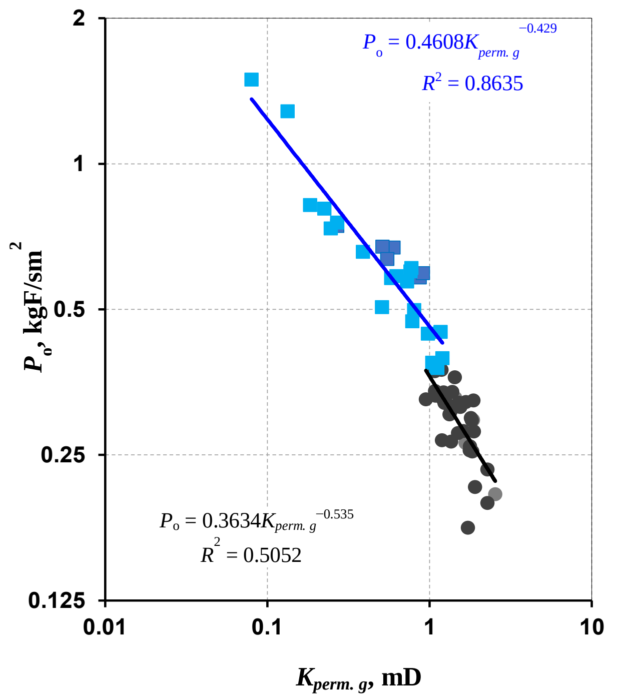


Fig. 14. Shearing pressure (P_o) versus absolute permeability for gas ($K_{perm.\,g}$)

Fig. 15. Pore space filling with carbonate material based on thin section photographs in transmitted light

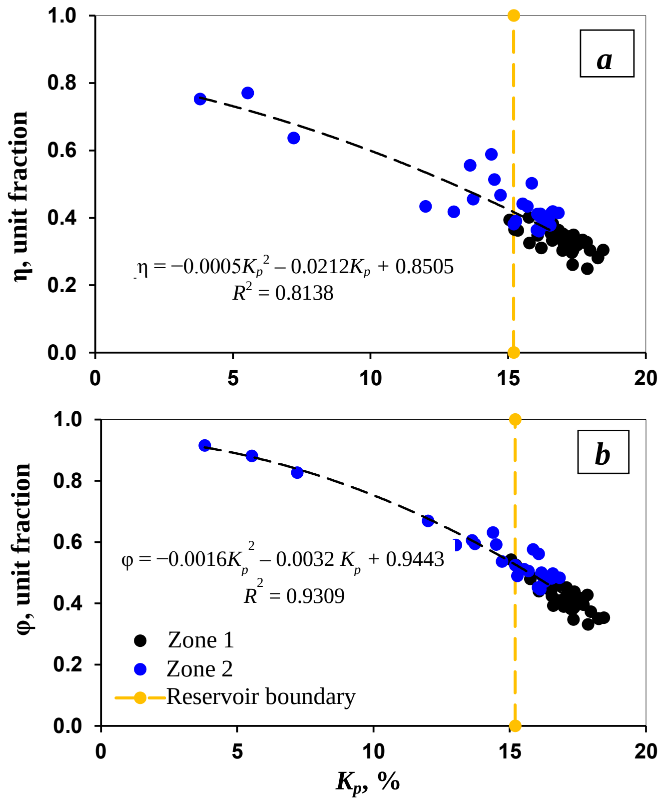


Fig. 16. Relative clay content (η) (*a*) and clay-carbonate content (φ) (*b*) versus open porosity (K_p)

Fig. 12 shows that in the rocks of zone 1, most of the filtration channels connecting the pores to each other has average radius ranging from 2.9 to 5.6 microns, whereas in the rocks of zone 2, from 0.7 to 2.5 microns. The analysis of the pore channel average radii showed that the size of the filtration channels of zone 1 is two times the size of the filtration channels of zone 2.

The pressure at which the liquid displacement begins (shear pressure) for the rocks of zone 1 ranges from 0.177 to 0.375 kgf/cm^2 (the average value is 0.297 kgf/cm^2), and that for the rocks of zone 2, from 0.378 to 1.494 kgf/cm^2 (0.641 kgf/cm^2) (Fig. 13, 14). At the pressure levels below the shear pressure, liquid displacement will not occur, and, as a result, oil will not displace water.

The analysis of the material composition showed that the content of clay and carbonate material in the pore space of the rocks has a fundamental effect on the size of the filtration channels (Fig. 15).

The clay volume K_{clay} and the carbonate volume K_{carb} values vary within the following ranges: for the rocks of zone 1, K_{clay} ranges from 6.1 to 10.5 % (the average value is 8.5 %) and K_{carb} ranges from 2.0 to 8.9 % (4,1 %); and for the rocks of zone 2, K_{clay} ranges from 9.1 to 20.5 % (12.1 %) and K_{carb}, from 3.3 to 31.1 % (8.4 %).

For the purpose of determining the degree of filling the rock pore space with clay and carbonate material, we calculated the relative clay content η and clay-carbonate content φ and compared them with the open porosity K_p (Fig. 16). The degree of filling the pore space with clay and carbonate material for the rocks of zone 1 ranges within 35–54 % (42 % on average), and that for the rocks of zone 2, 45–92 % (57 %).

Fig. 16 shows that in the rocks of zone 1, the degree of filling of the pore space with clay and carbonate material is much less than that in the rocks of zone 2.

Conclusion

Based on the implemented analysis, we conclude that the uneven hydrocarbon saturation of the AC10 formation is due to the microheterogeneity of these rocks.

The sediments of the AC10 formation correspond to the littoral facies complex, whose origination conditions determine wide variability of the lithological and mineralogical composition and textural-and-structural features, that led to the microheterogeneity of these rocks.

The high content of clay and carbonate material in the pore space of the rocks of the AC10 formation produced fundamental effect on the size of the filtration channels and, as a result, determined the uneven hydrocarbon saturation.

Since the geophysical well logging data are aimed at studying macroheterogeneity, the filler composition, its amount in the pore space, and the (core) hydrocarbon saturation collectively evened the AC10 formation electrical resistance in different saturation zones that led to distortion of the hydrocarbon saturation of the reservoir as a whole.

To increase the confidence of hydrocarbon saturation estimation for the AC10 formation rocks, the lithological-petrophysical and geophysical data should be applied in combination. It is necessary to formulate the systematic approach to solving such problems.

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