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Reservoir properties of effusive rocks of the Muradkhanli field (Azerbaijan)

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The presence of oil accumulations in igneous rocks has been known for quite a long time. Geologists estimate that oil reserves in eruptive and weathered metamorphic rocks reach 1 % of the world's proven oil reserves. At the Shaimskoye field (Western Siberia), oil is found in the weathered granites of the basement. Oil has been found in eruptive rocks in Texas (USA) fields, the most famous of which is the Litton Springs field. Oil is found in metamorphosed shales in the western part of the Los Angeles basin, the porosity of which is caused by the development of cracks in the roof of crystalline shales. Petroleum is extracted from serpentinites in Cuba. Basic igneous rocks contain petroleum at the Ferbro field in Mexico.At the Khukhrinsky gas field, which islocated at the north-western end of the Dnieper-Donets depression, the crystalline basement rocks are oil and gas bearing, from which commercial hydrocarbon inflows have been obtained. In the White Tiger field (Bach Ho), located on the southern shelf of Vietnam, commercial oil accumulations are also found in crystalline basement rocks.

At the Muradkhanli field in Azerbaijan, the industrial accumulation of petroleum belongs to the igneous rocks of the Upper Cretaceous age. The natural oil and gas reservoir of the Muradkhanli field is confined to the erosion zone of the upper part of the section of these rocks.

This work aims to determine the reservoir properties of the rocks of the Muradkhanli deposit, which belong to igneous rocks, in different ways.

The method of estimation of final oil recovery of complex structure reservoirs was proposed for useful capacity and oil recovery of homogeneous media; different variants of the volumetric method were used for reservoirs with complex structures of pore space filling a complex and heterogeneous natural reservoir; values of hydrocarbon reserves of increased and secondary capacity were calculated for the study interval; distributions of oil reserves with right-sided asymmetry, where $Mo<Me<X$, were presented; it was determined that in effusive cores oil saturation and fluid filtration are caused by tectonic fracturing and cavernousness.

Permeability varies in a wide range: $0.73\cdot10^{-15}$—$1.31\cdot10^{-15}$ m^2; the largest specific fraction of crack density is in the range 0—0.1 cm/cm^2, the average value is 0.29 cm/cm^2, with crack depth they decrease from 0.9 to 0.1 cm/cm^2.

The studies have shown that the natural reservoir of oil and gas in the Muradhanli field is associated with the erosion zone of the upper part of the igneous rock section.

Key words: field, igneous rocks, reservoir, porosity, permeability, crack.

Introduction. The Muradkhanly deposit is located within the Srednekurinskaya depression [Kocharli, 2015; Seidov, Khalilova, 2019; Seyidov, Shakhnazarov, 2019; Khalilov et al., 2019; Seidov, Alibekova, 2022]. The geological structure of the field involves a complex of sediments from the Quaternary to the Cretaceous. The largest oil deposit is explored in

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the magmatic rocks of the Upper Cretaceous (Fig. 1). The productivity of the sedimentary complex of the Eocene age and Chokrak is much weaker. The field section was formed under the influence of geological processes such as interruption of sedimentation, tectonic deformation, erosion, and volcanic activity.

The primary uplift in the Muradkhanly area is due to an effusive complex of Upper Cretaceous age rocks. This uplift is covered with Paleogene-Miocene sediments, which in turn are covered with a Pliocene-Anthropogenic complex that was not involved in folding [Alizada et al., 2013; Akhmedov, Aghayeva, 2022; Kerimova, Aliyev, 2022; Kerimova, 2023].

In the elevated zone of the structure, effusive formations are consistently covered with Maikop Formation sediments (Oligocene—Lower Miocene), and on the southern and western dips — by Eocene sediments.

Mesozoic effusive rocks are represented by pyroxene andesites, biotite, hornblende and pyroxene trachyandesites, porphyritic and almond-shaped basalts.

As a result of epigenetic processes, the upper part of the Cretaceous sediments is represented by both altered effusive rocks in their original setting and re-deposited products of their processing mixed with sedimentary material. Tuff-sandstones, tuffogravelites and tuffobreccias occur in the uppermost part of the section.

The structure of the Muradkhanly deposit on the surface of the effusive formations (Fig. 2) is a brachyanticlinal fold extending in the northwest-southeast (NW-SE) direction. The fold is complicated by discontinuities that divide it into three blocks. The faults are of a discharge nature.

The natural reservoir in Cretaceous sediments is confined to the upper part of the effusive rock section. It is bounded from above by the surface of the stratigraphic discord formed by the transgressive covering of the Cretaceous sediments with thick Maikop clays in the vault part of the uplift and Eocene clays on the western wing. The Upper Cretaceous effusive igneous rocks in the process of epigenetic transformations of the up-

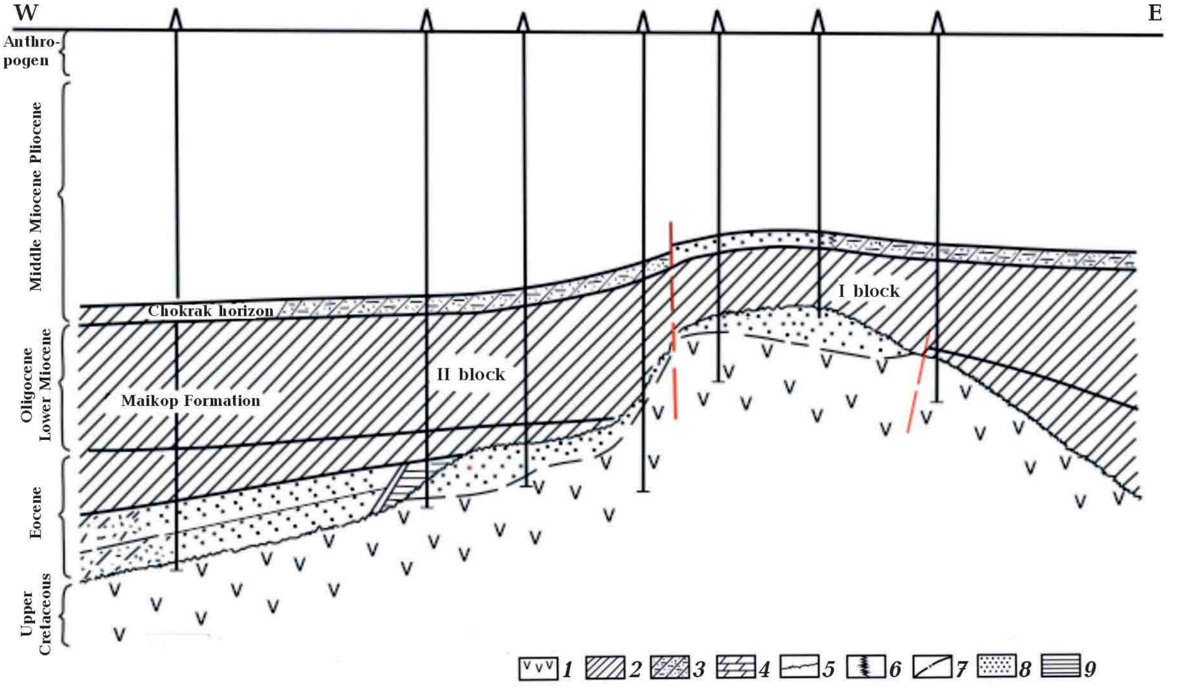

Fig. 1. Muradkhanly deposit. Geological section: *1* — effusive formations, *2* — clays, *3* — sandy-silty-clay alternation, *4* — marls, *5* — surface of effusive formations, *6* — boundaries of deposits in the Chokrak, supramergic and marl beds of the Eocene, *7* — boundaries of deposits in effusive formations, *8* — oil deposits, *9* — zone of absence of reservoirs in the Eocene.

per part of their section are represented by both altered effusive rocks in their original occurrence and re-deposited products of their processing mixed with sedimentary material.

The surface of the effusive formations is quite clearly recorded by geophysical well surveys (GWS), but the correlation of well sections within the effusive formations is considerably difficult and often tentative [Kocharli, 2015; Akhmedov, 2019a, b; Agayeva, 2020, 2021].

A detailed study of the geological structure and oil and gas content of the Muradkhanly field was dictated by the need not only for rapid additional exploration and delineation but also for putting the field into development, as well as improving the overall efficiency of prospecting and exploration on similar neighbouring structures.

The Muradkhanly deposit has been thoroughly analyzed from a geological and geophysical points of view. For this reason, petrophysical parameters characterizing the rocks composing the field have been determined using various methods, and certain results have been obtained.

Methods. To calculate proven oil reserves in complex effusive reservoirs, the estimated parameters can be represented in the form of probability distributions of their actual values or, in case of a limited number of observations, in the form of triangular distributions, for the realization of which it is sufficient to know the minimum, maximum and most probable values of the estimated parameters. The use of not only mean values but also the variation limits of the parameters for estimation of reserves allows to use also additional

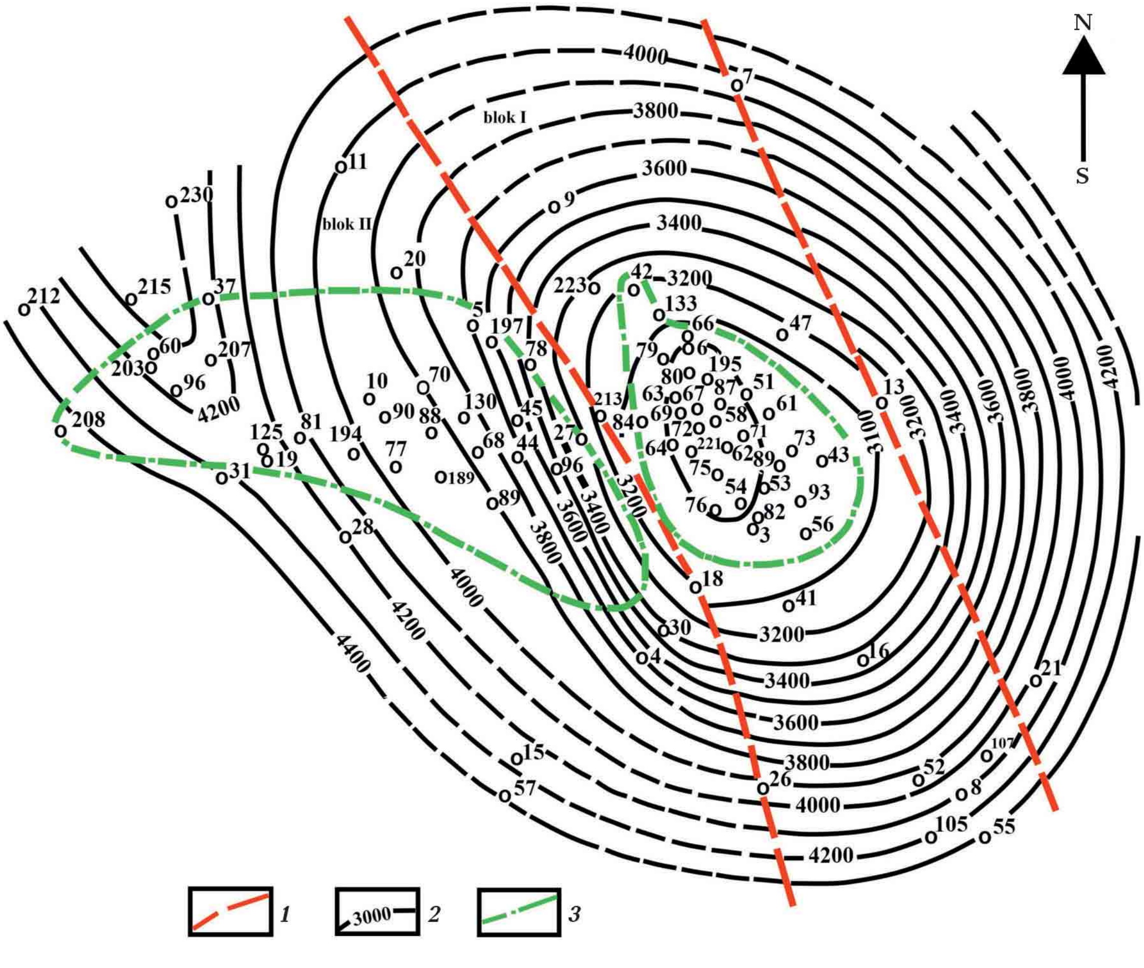

Fig. 2. Muradkhanly field. Structural scheme on the deposit roof in effusive formations: *1* — tectonic fracture lines, *2* — isolines of the structure roof, *3* — oil-bearing contour.

information, which increases the accuracy of reserves estimation. Importantly, the shape of the distribution of the estimated parameters does not significantly affect the results.

In conditions of insufficient data volume, a priori information on the region or similar fields can be used to form triangular distributions. Statistical testing (Monte Carlo method) should be used for calculations [Foulkes et al., 2001].

This approach to estimating oil and gas reserves allows us to get a probabilistic model of reserves that incorporates both the possible limits of change in reserves and their average value with an estimate of confidence intervals and reliability coefficient. Based on these indicators, a more reliable estimate of reserves in complex geological conditions is possible.

The oil-saturated volume of the effusive reservoir in the Muradkhanly field was estimated using two methods. Firstly, by geological and field method (GFM), the secondary capacity within the productive and tested part of the section based on core samples is calculated, taking into account the limitations imposed on the effective thickness by well test results. Secondly, based on GWS, effective oil-saturated intervals with increased capacity are identified using field geophysics data.

Both approaches are based on the same fracture-cavernous-pore reservoir model but take into account the distribution of secondary capacity in the reservoir volume differently.

The first approach can be called integral or volumetric. In this case, the intervals with increased secondary capacity seem to «dissolve» in the volume of the productive part of the deposit. The second approach is the-differential or interval approach. It makes it possible to identify intervals with significantly increased intergranular secondary capacity and intensively developed fracturing in the deposit section. The first approach, giving an integral estimate of the effective void space, does not allow selecting the intervals of the section, which are of the greatest interest for sampling. The second approach, devoid of this disadvantage, does not estimate purely fractured intervals characterized mainly by low capacitive properties. Thus, the integral estimation should give a larger value of reserves.

We also applied methods of determining specific fracture porosity and radial filtration and carried out studies of slurries.

Application and discussion. The average porosity of rocks in productive intra-contour wells was 13.3 %, and in unproductive out-contour wells — 11.7 % (Fig. 3). The average permeability of the intra-contour wells in separate parts of the deposit is $1.44{\cdot}10^{-15}$ and $8.77{\cdot}10^{-15}$ m^2.

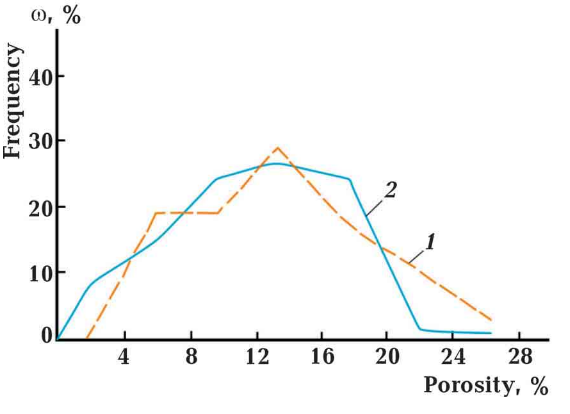

Fig. 3. Porosity distribution curves of effusive rocks by productive (*1*) and non-productive (*2*) wells.

A large number of fracture-specific gravity determinations have been performed. The largest number of determinations falls in the interval 0—0.1 cm/cm^2. The average value of the specific density of cracks was 0.29 cm/cm^2. The specific fracture density decreases with depth from 0.9 to 0.1 cm/cm^2.

The fracture permeability, in addition, was investigated by the radial filtration method. This method provides a higher probability of participation of cracks in filtration, allowing samples of smaller sizes. The permeability values obtained in this case characterize the value of fracture permeability, which is calculated by a formula similar to the Dupuis formula [Mishchenko, 2003]. Studies have shown that intergranular porosity is many times higher than fracture porosity, and intergranular permeability is much lower than fracture permeability.

Petrographic and structural characteristics of the void space were also studied on normal-sized thin sections. The study of thin sections from effusive rocks of the Upper Cretaceous, represented by andesitic porphyrites with phenocrysts of large plagioclases and biotite, showed the presence of oil in pores, caverns, and cracks in unextracted samples and filling of almost the same areas with bakelite varnish after extraction of samples. Cracks filled with crystalline calcite and bitumen are observed. Among the voids, pores predominate, less frequently microcracks. Pores are found not only in the main mass but also in separate mineral phenocrysts; irregular shape of pores prevails, their distribution in the rock and bitumen saturation are uneven. Pores are usually connected by tiny channels.

Studies of a sample from the 3590—3596 m interval in borehole 27 showed that pores and fractures developed in leached feldspars and pyroxenes are filled with dye. The pores are

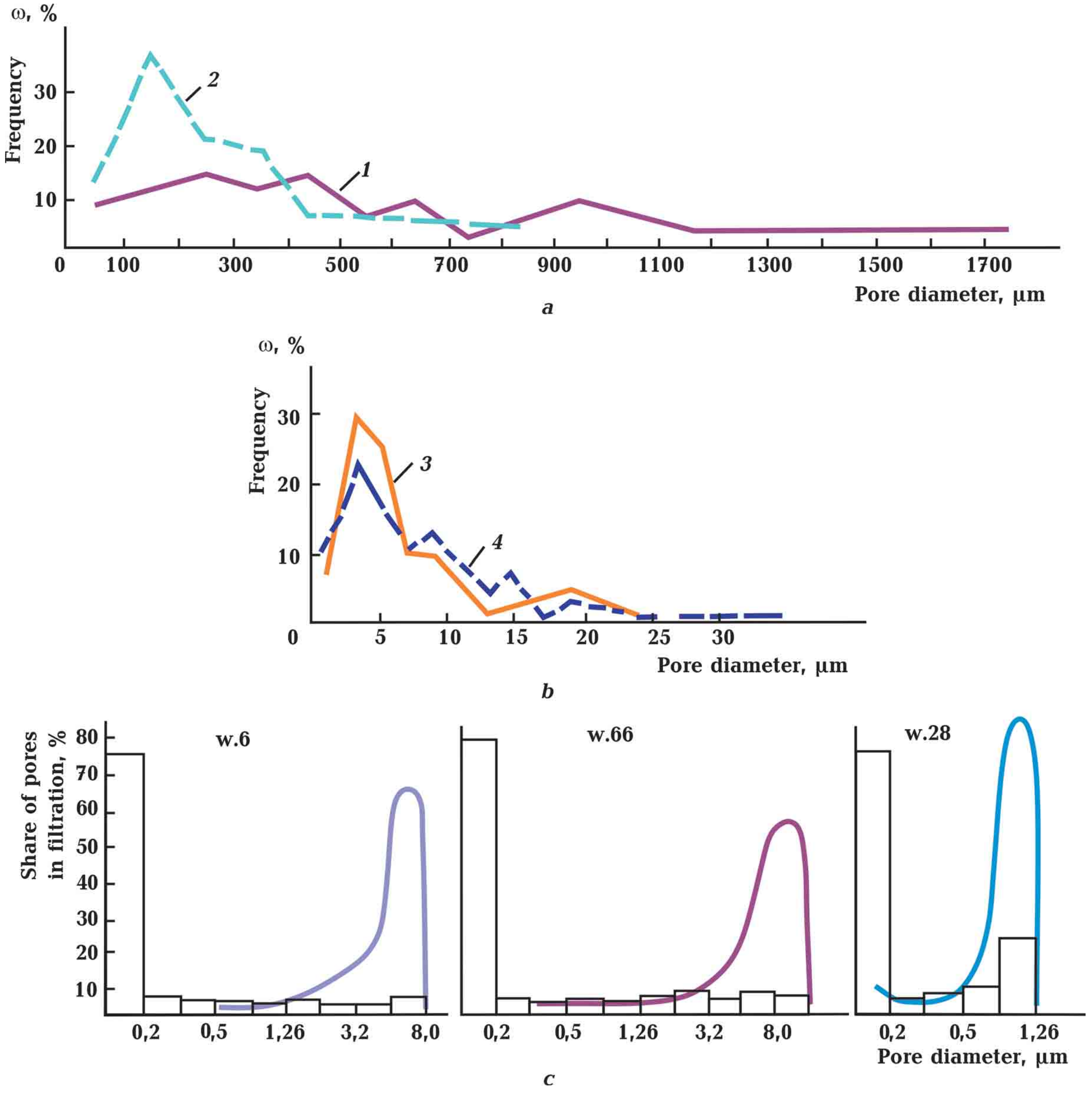

Fig. 4. Distribution of pore sizes of effusive rocks based on slides (*a*), microphotographs of rock chips (*b*), and mercury porometry (*c*). Pore size: *1* — maximum, *2* — minimum, *3*, *4* — by core depth (*3* — 3031—3034 m, *4* — 3027—3031 m). In Fig. 4, *c* distribution: stepwise — porosity, curve — permeability.

connected with microcracks of weathering and tectonic origin. Pores and cleavage cracks of tectonic origin are partly filled with calcite and chlorite, partly filled with colorant.

In the plane-parallel sections, studies were carried out to determine pore sizes. As shown (Fig. 4), pore size distributions in effusive rocks are asymmetric. There are caverns larger than 1000 μm. Fig. 4 shows the dependence of porosity and permeability increases with the rise in pore size, according to these studies.

The pore space of the samples was also investigated by mercury indentation or mercury porometry. The plots of porometric curves allow us to observe the distribution of pores and estimate their fractional participation in filtration. For nine samples from the Upper Cretaceous, it was found that the matrix is dominated by pores with a radius less than 0.1 μm, the content of which is 61—76 %, except for the sample from well 224 (interval 3031—3035 m), in which the content of pores of this size increases to 95 %. The maximum pore size of the group of samples from wells 18, 42, and 224 is 1—1.6 μm, while in other samples (wells 6, 66, and 213), it increases to 4.0 and 6.3 μm. The average radius of open pores varies from 0.191 to 1.187 μm. The range of pore channel sizes determining filtration in wells 18, 42, and 224 is within 0.25—1.6 μm, in wells 6 and 213 — in the intervals 0.63—4.0 μm, and in well 66 — 1.6—6.3 μm. The theoretical permeability values of microporous samples (wells 18, 42, and 224) vary from $0.25 \cdot 10^{-17}$ to $13.75 \cdot 10^{-17}$ m^2.

In Fig. 4, *c*, the dependence of porosity (stepwise distribution) and the dependence of permeability (curve distribution) on the filling of the pores in the reservoir due to filtration during gas extraction is presented. In this case, while porosity remains uncertain, permeability increases rapidly.

In the group of samples from wells 6, 66, and 213, permeability increases to $0.73 \cdot 10^{-15}$ m^2, and in well 66 — to $1.31 \cdot 10^{-15}$ m^2. The open porosity varies from 3 to 25 %; the effective porosity, respectively, from 1—2 to 9 %.

The porosity coefficient in the structures forming the oil and gas fields in Azerbaijan varies from 0.01 (minimum pores) to 0.33 (maximum pores). (Fig. 4, *a*, *b*; Fig. 5, *a*, *b*).

There is a power dependence (Fig. 5, *c*) of the kind between matrix permeability and radius of pore channels: $K_{per}=0.33r^{2.48}$, which characterizes the matrix structure.

The high open porosity and low core permeability of effusive rocks are explained by the rock's fine-grained and finely porous structure which retains a significant amount

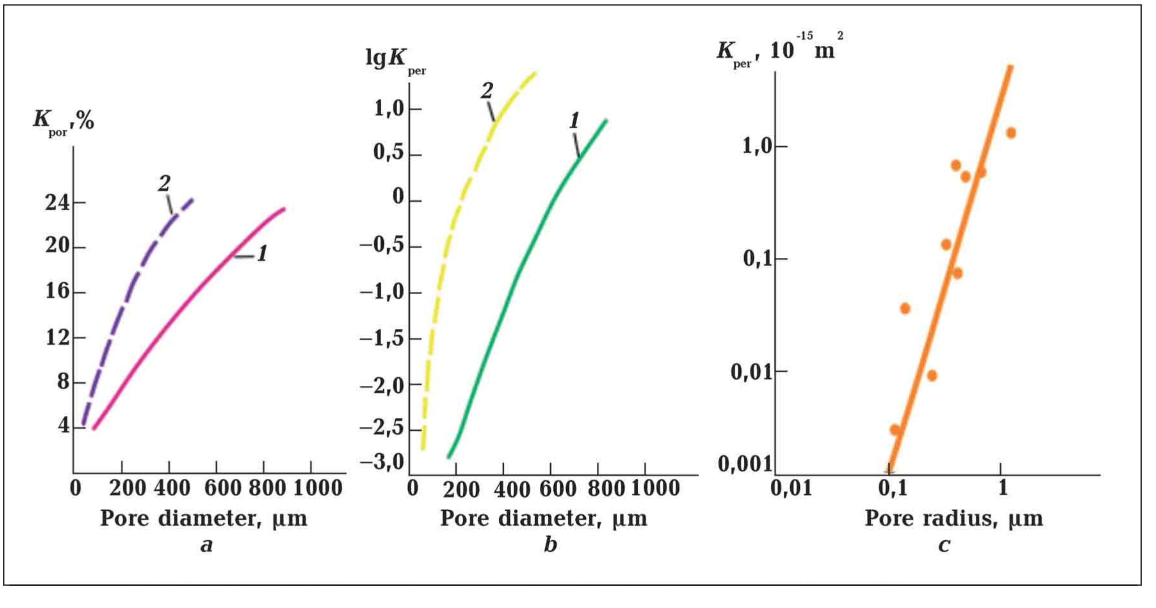

Fig. 5. Dependence of porosity (*a*) and permeability (*b*) on the maximum (*1*) and minimum (*2*) pore sizes determined from slits, and permeability on pore radius (*c*) determined from mercury porometry data.

of firmly bound water in the pore intergranular space, characterized by a complex configuration and high tortuosity.

The observed differences in quantitative pore size estimates are known to be due to differences in the methods used. As the comparison data of three methods (mercury indentation, mercury porometry, scanning electron microscope (SEM)) show, only SEM and mercury porometry methods are comparable in characterizing the smallest pores of the rock matrix. Based on the studies, the matrix of effusive rocks can be characterized mainly as finely porous. The development of large-sized pores, caverns connected by a system of fractures, can be traced visually or in thin sections.

The formation of reservoir properties of effusive rocks is due to the leaching and transformation processes of the original volcanogenic material. As a result of catagenetic processes, the effusive rocks, along with tectonic fracturing, acquired cavities (large pores and caverns) due to the deformation and destruction of plagioclase grains and colored rock components. The productive part of the effusive rock section, along with the system of microcracks, is characterized by the presence of macrocracks. This is confirmed by significant drilling fluid absorption during drilling (up to 100 m^3/day) when penetrating the upper effusive formations and by high oil flow rates (about 500 tones/day) when testing and operating some wells.

Thus, the study of the Upper Cretaceous deposits at the field showed that the reservoirs in the effusive rocks are represented by a complex fracture-cavernous-pore type. Oil saturation is mainly associated with secondary porosity. Along with caverns and micro and macro fractures containing the main oil reserves, partial saturation of the rock matrix is noted in some zones of the deposit, in the zones of contact with fractures.

To quantify the total secondary capacity associated with oil saturation within the sampled and productive part of the section, we used the results from intra-contour wells that yielded oil inflows and out-contour wells that did not yield fluid inflows. Since oil deposits in the effusive formations of the Muradkhanly field are confined to two hydrodynamic isolated blocks, data were processed and generalized separately for each block. To determine the porosity, 72 porosity analyses from intra-contour wells and 126 analyses from dry out-contour wells were used, which were distributed by blocks as follows: intra-contour — I block —38, II block —34; out-contour wells — 92 and 34 analyses, respectively (Table). Porosity distribution series were plotted, and the average values were calculated for intra-

Porosity distribution by inner-contour and out-contour wells that penetrated effusive formations

Porosity variation intervals, %	Intra-contour wells				Out-contour wells			
	I block		II block		I block		II block	
	Analysis frequency	Probability degree	Analysis frequency	Probability degree	Analysis frequency	Probability degree	Analysis frequency	Probability degree
0—4	1	0.026	—	—	7	0.076	3	0.088
4—8	8	0.210	6	0.176	10	0.109	9	0.265
8—12	6	0.158	8	0.236	23	0.250	7	0.206
12—16	8	0.210	13	0.383	27	0.293	7	0.206
16—20	7	0.185	6	0.176	23	0.250	7	0.206
20—24	6	0.158	1	0.029	1	0.011	1	0.029
24—28	2	0.053	—	—	1	0.011	—	—
∑	38	1.000	34	1.000	92	1.000	34	1.000
Average porosity value, %	14.0		12.6		12.4		11.0	

contour and out-contour wells separately by blocks.

A comparison of the two porosity distributions (Fig. 6) allowed us to determine the difference between their average values, which characterizes the effective secondary capacity of effusive rocks.

The secondary capacity (K_{sec}) was calculated by the formula $K_{sec} = \frac{K_{i.c.} - K_{o.c.}}{1 - K_{o.c.}}$, where $K_{i.c.}$— porosity in productive intervals of the section in intra-contour wells, $K_{o.c.}$— porosity in unproductive (dry) intervals of the section in out-contour wells. The value of secondary capacity was 1.8 %.

The secondary capacity determined in this way characterizes the entire tested thickness of the deposit, within which there are intervals with increased porosity due to transformations of the intergranular space of the rock matrix and intervals where the effective porosity is significantly lower and commensurate with the fracture capacity. It can be assumed that the oil saturation of the secondary capacity is high enough and approaches 90 %.

Thus, the study of the core-based capacity of effusive reservoirs within and outside the deposit allowed us to propose a method for estimating secondary porosity based on comparing the porosity distributions of intra-contour and out-contour wells and determining the difference between their average values.

To quantify the total secondary capacity associated with oil saturation of the productive part of the section, we used the results of analyses of rock samples from intra-contour wells that yielded oil inflows during sampling and from out-contour wells that did not yield fluid inflows. Comparison of the two porosity distributions allowed us to determine the difference between their average values (1.8 %), which characterizes the effective secondary capacity of effusive rocks.

The secondary capacity determined in this way characterizes the entire tested thickness of the deposit, within which there are intervals with increased porosity due to secondary transformations of the intergranular space of the rock matrix and intervals where the effective porosity is significantly lower and commensurate with the fracture capacity. It can be assumed that the oil saturation of the secondary capacity is quite high.

Since secondary porosity is developed within

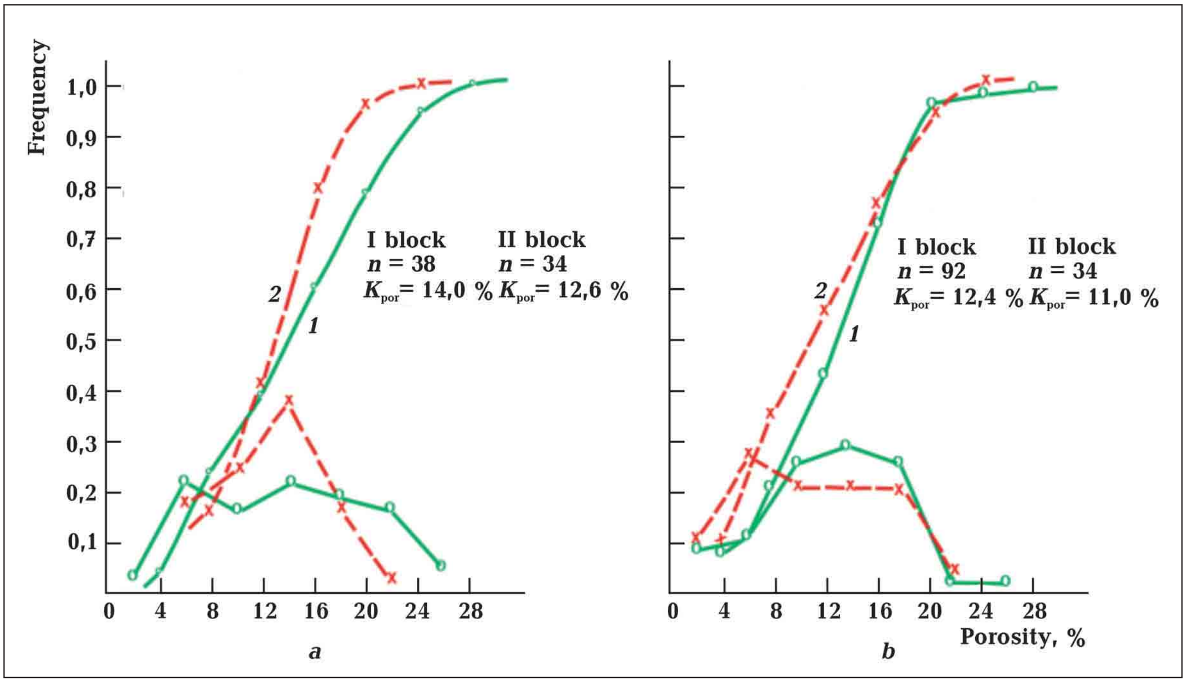

Fig. 6. Muradkhanly field. Differential and integral curves of porosity distribution in intra-contour (*a*) and dry (*b*) wells: *1* — Block I, *2* — Block II, *n* — number of core samples.

the entire oil-saturated volume, the oil-saturated thicknesses were determined considering this factor. To determine them, we used data from interval open-hole sampling of wells in the process of penetrating the effusive section, formation-testing results, and flow test data in the production string after the well drilling was completed. In some cases, when the sampling results could not be interpreted unambiguously, the oil saturation boundary was adjusted based on logging data. Within the highly productive zones of Blocks I and II, the oil-saturated thickness was assumed to be maximum by analogy with well 3 in Block I (113 m) and well 5 in Block II (105 m), which penetrated the entire thickness of the deposits. The average oil-saturated thicknesses of the deposits in Blocks I and II were estimated from isopachite maps (Fig. 7) and were 47 and 38 m, respectively.

Intervals of the section with increased total porosity due to secondary pores, matrix caverns, and fractures are identified using a combination of logging (electrical, radioactive, and acoustic logs, cavernometry) and well test data. The thickness of these intervals can be taken as the effective oil-saturated thickness. Allocation of such intervals and estimation of their total porosity was carried out using a set of GWS according to the known method of supporting strata. The distinctive feature of the method was the use of apparent secondary porosity of oil-saturated intervals and the determination of two conditioned porosity limits: lower — for separation of dense unproductive rocks with porosity less than 7—8 % and upper — for rocks with the content of highly dispersed minerals more than 40 % for separation of water-saturated rocks with total porosity more than 20 %. Electrometric methods were used to calculate intergranular porosity and oil saturation coefficient.

Integral and differential approaches were applied to the Muradkhanly field. It can be seen that the integral approach yields higher hydrocarbon reserves estimates than the differential approach (Fig. 8).

Analysis of calculations has shown that oil reserves in reservoirs of complex type are represented by distributions with right-sided asymmetry, where the top of the distribution is shifted to the left. Such distributions between

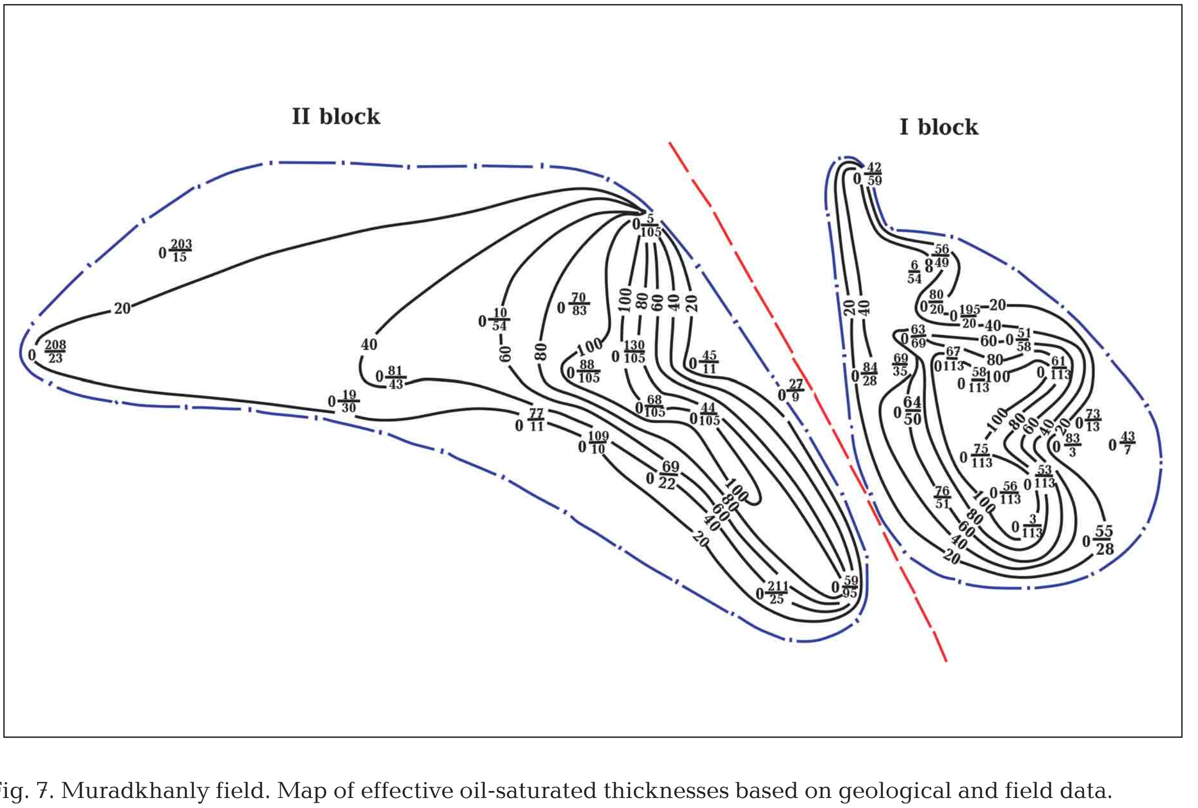

Fig. 7. Muradkhanly field. Map of effective oil-saturated thicknesses based on geological and field data.

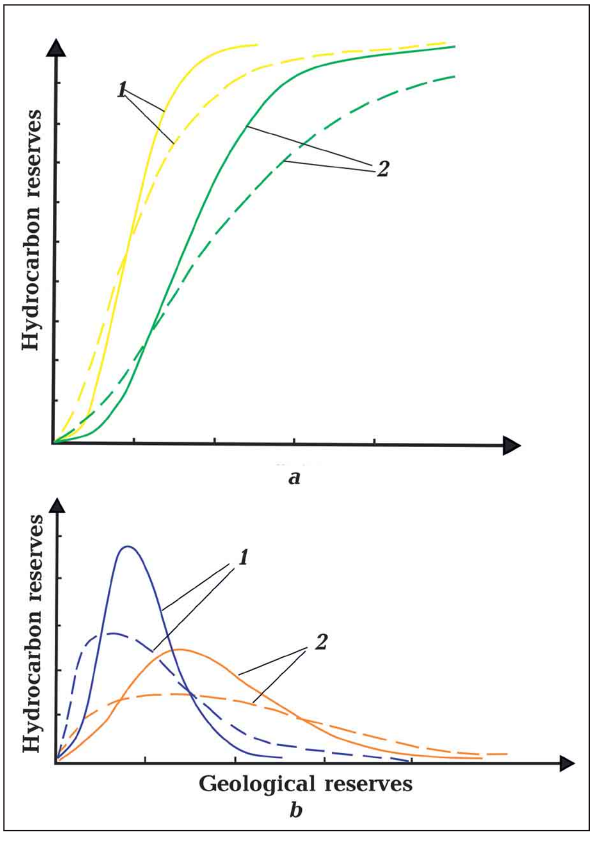

Fig. 8. Integral (*a*) and differential (*b*) curves of oil reserves according to geological and field data (dotted line) and GWS (solid lines) for I (*1*) and II (*2*) blocks of Muradkhanly field.

mean (*X*), mode (*Mo*), and median (*Me*) are characterized by the following relationship: *Mo*<*Me*<*X*. In the method using GWS data, the variability of the estimated parameters (especially effective thickness) is smaller than in the method based on geological and field data (GFD). Therefore, in the former case, the variation of reserves is 40—45 %, while in the latter case, it reaches 69 %. For the first block, both methods give close reserve values, with median differences of plus 2 %, mode differences of minus 4 % and mean values of plus 14 %. In the second block, reserves from the GFD exceed those from the GWS data by +18, +14, and +32 % in median, modal, and mean estimates, respectively.

Thus, the reserves that take into account the secondary capacity in the entire volume of the deposit are somewhat higher than the reserves calculated for the intervals of increased and secondary capacity allocated according to GWS data. The method of calculating reserves within the entire deposit volume should be preferred, as it considers the specifics of the reservoir model more fully.

Various methods were used to analyze the reservoir properties of the Muradkhanly field, which is composed of igneous rocks. A brief analysis of the results obtained is given below.

The different variants of the volumetric method used for reservoirs with complex pore space structures filling a complex and heterogeneous natural reservoir provide the most reliable information about the hydrocarbon reserves.

The enhanced and secondary hydrocarbon reserves calculated for the study interval are usually higher than the actual values. The reason is that the secondary capacity values in the entire volume of the deposit are incorrectly calculated from the data of geophysical well surveys.

Studies have shown that permeability varies in the range from $0.73 \cdot 10^{-15}$ to $1.31 \cdot 10^{-15}$ m^2, the highest value of specific fracture density 0—0.1 cm/cm^2, average 0.29 cm/cm^2, with depth fractures decreasing from 0.9 to 0.1 cm/cm^2, porosity limit: non-productive rocks with porosity less than 7—8 %, highly dispersed minerals more than 40 %.

It was established that the natural reservoir of oil and gas of Muradkhanly field is confined to the erosion zone of the upper part of the igneous rocks section, and in effusive reservoirs, oil saturation and fluid filtration are caused by tectonic fracturing and cavernosity.

Results. In conclusion, we note that for reservoirs with complex pore space structures filling a complex and heterogeneous natural reservoir, it is productive to use various variants of the volumetric method of reserves estimation in combination with the method of statistical tests to obtain interval-probability estimates, compare them and select the most reliable values of hydrocarbon reserves.

Conclusions. The studies have shown that the natural oil and gas reservoir of the Muradkhanly field is confined to the erosion zone of the upper part of the magmatic rocks section. It is bounded from above by the stratigraphic discord surface, formed by a transgressive covering of Cretaceous effusive rocks with thick Maikop clays in the vault part of the uplift and Eocene clays on the western wing.

It was established that the secondary porosity of effusive reservoirs, with which oil saturation and fluid filtration are associated, is caused by tectonic fracturing and cavernosity due to catagenetic transformations; the primary matrix is characterized mainly by a fine-porous structure and only 20—25 % of the pore volume has pore sizes providing filtration, thus a step dependence between permeability and radius of pore channels is observed; a method of estimation of secondary capacity from the core based on comparison of intra-contour and out-contour porosity distributions is proposed.

An estimation method of ultimate oil recovery of complex structure reservoirs (heterogeneous medium) by attracting a priori data on useful capacity and oil recovery of homogeneous media is proposed. The weighting of oil recovery of mixed homogeneous media by the values of specific useful capacity of reservoirs ($K_{\text{p}} \times K_{\text{o.s.}}$) is essential.

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Колекторські властивості ефузійних порід родовища Мурадханли (Азербайджан)

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Про наявність скупчень нафти в магматичних породах відомо доволі давно. За оцінками фахівців-геологів запаси нафти у вивержених та вивітрених метаморфічних породах досягають 1 % від розвіданих світових запасів нафти. На Шаїмському родовищі (Західний Сибір) нафту знайдено у вивітрілих гранітах фундаменту. У вивержених породах виявлено нафту на родовищах штату Техас (США), серед яких найбільш відомим є родовище Літтон-Спрінгс. У західній частині басейну Лос-Анджелес нафта залягає у метаморфізованих сланцях, пористість яких зумовлена розвитком тріщин у покрівлі кристалічних сланців. Із серпентинітів видобувають нафту на Кубі. На Хухринському газовому родовищі, що розміщується на північно-західному закінченні Дніпровсько-Донецької западини, нафтогазоносними є утворення кристалічного фундаменту — з них отримані промислові притоки вуглеводнів. На родовище «Білий тигр» (BachHo) (південний шельф В'єтнаму) промислові скупчення нафти також знайдені в кристалічних породах фундаменту.

На родовищі Мурадханли в Азербайджані промислове скупчення нафти виявлена у магматичних породах пізньокрейдяного віку. Природний резервуар нафти та газу родовища Мурадханли тяжіє до зони ерозії верхньої частини розрізу цих порід.

Мета даної роботи: визначення різними способами колекторських властивостей магматичних порід родовища Мурадханли.

Запропоновано спосіб оцінювання кінцевої нафтовіддачі колекторів складної будови для корисної ємності та нафтовіддачі гомогенних середовищ; використані різні варіанти об'ємного методу для колекторів зі складною структурою порового простору, що заповнюють складний та неоднорідний природний резервуар; для інтервалу дослідження розраховані запасів вуглеводнів підвищеної та вторинної ємності; наведено розподіл запасів нафти з правосторонньою асиметрією, для яких характерне співвідношення $Mo<Me<X$; встановлено, що в ефузивних колекторах нафтонасичення та фільтрація флюїдів обумовлені тектонічною тріщинуватістю та кавернозністю.

Проникність змінюється в широкому діапазоні: $0{,}73\cdot10^{-15}$—$1{,}31\cdot10^{-15}$ м^2; найбільше значення питомої щільності тріщин 0—0,1 см/см^2, середнє — 0,29, з глибиною тріщини ці значення зменшуються від 0,9 до 0,1 см/см^2.

Дослідження показали, що природний резервуар нафти та газу родовища Мурадханли тяжіє до зоні ерозії верхньої частини розрізу магматичних порід.

Ключові слова: родовище, магматичні породи, колектор, пористість, проникність, тріщина.