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DEVELOPMENT OF OIL EXTRACTION SCREENING METHODOLOGY TAKING INTO ACCOUNT INNOVATIVE METHODS USING THE EXAMPLE OF THE UKRAINIAN FIELD

The object of research in the paper is the process of fluid transfer through the pore space of the reservoir rock. The traditional method of estimating oil recovery by flooding has a large number of uncertainties. In this study, to address limitations of the current approach to determining oil production, let's introduce a systematic algorithm aimed at enhancing result precision.

The methodology for calculating the oil recovery coefficient for determining the amount of oil that can be extracted by flooding is presented. In this work, the step-by-step process of determining the oil recovery coefficient was analytically established, which achieves a certain degree of accuracy due to the inclusion of a number of methods of calculation of scientists from different countries of the world. In particular, the lithofacies distribution of the reservoir using the kriging method, the use of a representative elementary volume (REV) to increase the accuracy of determining the irreducible water saturation of each facies, and the use of the Buckley-Leverett equation in the calculation of the oil recovery coefficient are proposed. The number of facies (sandstone, argillaceous sandstone, siltstone) was determined on the example of the B-16n horizon of the «Ukrainian deposit» and the oil recovery coefficients were calculated for each separately (0.53, 0.47, 0.29). Further determination of the average oil recovery coefficient is described in the researched and requires close integration of the obtained data in three-dimensional space, as it allows to calculate the fraction of facies content in the reservoir volume.

The use of the proposed action algorithm will help to build a more reliable three-dimensional hydrodynamic model, will lead to a much lower degree of uncertainty of reservoir properties, and in particular irreducible water saturation, as well as more accurate distribution of lithological properties using kriging. Also, this methodology for calculating the oil recovery coefficient involves the use of the Buckley-Leverett equation and fractional flow curves, the data of which are based on relative permeabilities and depend on the irreducible water saturation determined in the laboratory for each lithofacies.

These techniques justify the collection of additional core material, the importance of lithofacies dismemberment of the formation and are closely integrated in the three-dimensional space, which makes it possible to simulate the existing processes, reproduce the proposed methodology and perform the forecast.

Keywords: *irreducible water saturation, representative elementary volume, kriging, relative permeability, fractional flow curves, oil recovery coefficient.*

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1. Introduction

For engineers tasked with estimating the oil recovery rate by waterflooding, it is imperative to achieve an accuracy that corresponds to future results [1, 2]. The challenge is to accurately determine the amount of reserves available for mining. In practice, there are still discrepancies between forecast indicators and actual values of mining reserves, which requires a more subtle approach.

This problem arises due to the failure to take into account decisive factors in the calculations according to the Ukrainian method of determining the coefficient of oil extraction. Lack of consideration of lithofacies distribution, including porosity, permeability, clay content, irreducible water saturation, gas saturation, and oil saturation, limits understanding of reservoir dynamics. In addition, the Ukrainian methodology lacks provisions for determining relative permeability [3], which characterizes different facies and prevents accurate modeling of fluid mass transfer. The use of averaged values over the entire reservoir introduces uncertainty in the prediction of oil recovery results [4, 5].

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Therefore, an urgent task is to create a methodology for determining the coefficient of oil recovery by flooding, the forecast results of which coincide with the actual data. The proposed innovative methodology eliminates these gaps by implementing a systematic algorithm. This algorithm covers a step-by-step process that integrates Western calculation methods, including lithofacies distribution using the Kriging method. In addition, it includes a representative elemental volume (*REV*) to improve the accuracy of the irreducible water saturation determination and uses the Buckley-Leverett equation to calculate the oil recovery ratio.

It is expected that the implementation of the proposed action algorithm will allow for obtaining a more reliable three-dimensional hydrodynamic model. This, in turn, is expected to reduce the degree of uncertainty in reservoir properties, particularly irreducible water saturation, and increase the accuracy in the distribution of lithological properties through the kriging method. The methodology additionally integrates Buckley-Leverett equations and fractional flux curves based on laboratory-derived irreducible water saturation data for each lithofacies.

These methods involve the collection of additional core material, emphasize the importance of lithofacies dissection and seamless integration in three-dimensional space. This integration facilitates the modeling of existing processes, validates the proposed methodology, and provides accurate forecasting. The importance of these achievements goes beyond theoretical considerations, influencing practical reservoir management strategies.

The object of research is the process of fluid transfer through the pore space of the reservoir rock.

The aim of research is to develop a new methodology for experimental determination of the oil recovery coefficient extracted by flooding.

2. Materials and Methods

The proposed research methodology includes several successive stages:

1. Identification of lithofacies: at the beginning, lithofacies in the formation are identified, taking into account porosity, permeability, clay content, irreducible water saturation, gas saturation, and oil saturation.

2. Core analysis is performed using available core material, combining laboratory-determined porosity values and facies information for each sample.

3. Determination of Representative Elemental Volume (*REV*): A Representative Elemental Volume (*REV*) is established using core data to analyze the minimum required number of samples representing the average porosity for each facies.

4. Calculation of irreducible water saturation: laboratory experiments are carried out with a certain number of core samples to find the average irreducible water saturation for each facies.

5. Permeability Curve Generation: Average irreducible water saturation values are used for each facie to generate unique permeability curves.

6. Application of the Buckley-Leverett equation and construction of fractional flow curves: fractional flow curves are constructed for each facies based on relative permeabilities, which allows dynamic representation of fluid mass transfer.

7. Calculation of oil recovery coefficient for each facies: oil recovery coefficients are calculated for each facies based on constructed fractional flow curves.

8. Reservoir Model Integration: The methodology is integrated into a 3D reservoir model, providing a powerful tool for fluid dynamics modeling and production prediction.

9. Determining the volume of facies: with the help of the kriging method and the variogram method, which are integrated into the software for building three-dimensional models, the volume of each facies in the reservoir is determined.

10. Calculation of the average coefficient of oil extraction: the average coefficient of oil extraction of the studied reservoir due to flooding is determined, taking into account the volumetric distribution of facies in the reservoir.

The starting material for the study is the core taken from the deposit. First, it is necessary to analyze the core and classify it as belonging to a certain type of facies. Such a distribution can be found by examining the core in a laboratory for various properties, such as porosity, permeability, clay content, and also by visual indicators.

The next step is the distribution of the core, with its corresponding facies affiliation, according to the property of porosity. The «porosity» property was chosen taking into account two factors. First, it has a close correlation with the property of irreducible water saturation. Secondly, to save money, laboratory studies of the core are usually limited to the determination of porosity, permeability, clay content. The property «porosity» can immediately be replaced by the property of irreducible water saturation if there is a sufficient amount of laboratory-determined data on irreducible water saturation for the cores of the relevant facies.

According to the Standard of the State Geodesy of Ukraine, the method of determining the coefficient of average effective porosity and other properties involves the calculation of the average value of the coefficient for the entire core sample in the given intervals of the reservoir depth [4]. This approach introduces inherent uncertainties regarding the specific value of average effective porosity and other properties for the entire reservoir.

In contrast to the Ukrainian standard, Western standards include the concept of representative elementary volume (*REV*) at each scaling stage [4, 5]. *REV* is the minimum volume of the studied rock sample required for a reliable average representation of any characteristic, guaranteeing an error not exceeding 0.5 % [6]. Determining this minimum sample volume for the characteristic being studied (e. g., porosity, connectivity) greatly reduces uncertainty, directly increasing the accuracy of the result.

For a spatially dependent variable f, determined in the pore space, the average value $F \equiv \overline{f}$ by volume V can be determined by the formula:

$$F = \frac{1}{V}\int f \mathrm{d}V,$$

where the integral can be both over a vacuum and over a solid body (where $f=0$).

For porosity $F \equiv \varphi$, $f=1$ in the pore space; for saturation phase p, $F \equiv \varphi S_p$ and $f=1$, where phase p is present in the pore space [2, 7].

The obtained values of the minimum required amount of core for each facies according to the property of porosity will be used for the laboratory determination of irreducible water saturation.

The industry standard of Ukraine for determining the coefficient of irreducible water saturation of rocks GSTU 41-00032626-00-025-2000 provides for the use of the Methodology for performing measurements by the method of centrifugation of samples.

The measurement method is based on modeling reservoir conditions of water saturation for samples previously made from the core of reservoir rocks. Samples are saturated with formation water (or its model of appropriate mineralization) and centrifuged. During centrifugation, part of the formation water (gravitational) is displaced from the sample under the action of centrifugal force, the rest remains in the void space. The use of different centrifugation modes allows the creation of different pressures to displace reservoir water from the sample.

The coefficient of water saturation (K_{ws}, in percent) is calculated according to the formula:

$$K_{wS} = 100\frac{m_{wS} - m_d}{m_w - m_d},$$

where m_{ws} – mass of the sample after centrifugation, g; m_d – dry sample mass, g; m_w – mass of a completely water-saturated sample before centrifugation, g.

Displacement pressure (p) depends on the centrifugation mode and is determined (in megapascals) by the formula:

$$p = 0.11\cdot 10^{-8}\cdot(\rho_1 - \rho_2)\cdot n^2\cdot R\cdot h\cdot\cos\theta,$$

where ρ_1 – formation water density, g/cm^3; ρ_2 – density of dry air, g/cm^3; n – rotation frequency of the centrifuge rotor, rpm; R – radius of rotation of the core sample, cm; h – height of the core sample, cm; Θ – angle of inclination of the sample to the horizon, degrees.

According to the results of the determination of the water saturation coefficient K_{ws} and the displacement pressure p, a capillary pressure curve is constructed – a graph of the dependence of the water saturation coefficient on the displacement pressure. The coefficient of irreducible water saturation in surface conditions (K_{ws}) is determined (in percent) by the capillary pressure curve and by the stabilized value of the water saturation coefficient K_{ws}.

The coefficient of irreducible water saturation, determined from the capillary pressure curve in surface (laboratory) conditions, is brought to reservoir thermobaric conditions by introducing a correction coefficient (α) according to the formulas:

$$K_{i.rc} = K_i\cdot\alpha,$$

$$\alpha = \frac{K_p}{K_{p.rc}},$$

where $K_{i.rc}$ – coefficient of irreducible water saturation in reservoir conditions, %; K_i – coefficient of irreducible water saturation in surface conditions, %; α – correction factor, 1; K_p – coefficient of open porosity in surface conditions, %; $K_{p.rc}$ – coefficient of open porosity in reservoir conditions, %.

Let's use the average values of the coefficient of irreducible water saturation for each facies to generate relative permeability curves. The coefficient of irreducible water saturation sets the first water saturation point of the relative curves, after which, with an increase in water saturation in the rock sample, water becomes mobile [3]. Also, when generating relative permeabilities, it is necessary to take into account the wettability property of the rock, which can be determined experimentally by applying a drop of water to the rock sample [2]. It should be noted that in the future, with the improvement of laboratory equipment, the generation of relative permeability curves may be replaced by the full volume of data on relative permeability found by experimental and laboratory methods.

When constructing the fractional flow curves for each facies, a number of the following statements were used:

– the Buckley-Leverett calculation uses relative permeability data and fluid viscosities to obtain displacement efficiency estimates;

– Frontal displacement theory involves using fractional flow and frontal advance equations;

– by combining the fractional flow equation with Darcy's equation, let's construct the fractional flow curve as a function of water saturation;

– further, let's plot the water saturation profile as a function of distance and time by using the frontal advance equation [8–10].

The basic equation is:

$$f_w = \frac{1}{1 + \frac{\mu_w k_{ro}}{k_{rw}\mu_o}},$$

where f_w – the point of the fractional flow curve corresponding to a certain saturation; μ_w – viscosity of water, mPa·s; μ_o – oil viscosity, mPa·s; k_{ro} – relative oil permeability corresponding to a certain saturation; k_{rw} – relative water permeability corresponding to a certain saturation.

Based on the obtained values of the fractional flow points of the corresponding facies, a curve is constructed on the water saturation profile as a function of distance and time. The point of irreducible water saturation, which is the beginning of the fractional flow curve, becomes the beginning of the output of the line that is tangent to the fractional flow curve. The continuation of the tangent line and its intersection with the extreme upper limit of relative permeability corresponds to the point of water saturation, which means water breakthrough [11–13]. The oil recovery coefficient for each facies is calculated separately according to the following formula:

$$RF = \frac{\bar{S}_w - S_{wi}}{1 - S_{wi}},$$

where RF – oil recovery coefficient; $\bar{S}_w$ – water saturation, which corresponds to the intersection of the tangent line with the maximum upper limit of relative permeability; S_{wi} – initial water saturation [14–16].

This step allows to find the oil recovery coefficient separately for each facies filling the studied reservoir. To find the average value of the oil recovery coefficient for the entire formation, it is necessary to build a three-dimensional model of the formation with the introduction of core and geophysical data on the wells of the relevant properties, such as porosity, permeability, clay, water saturation, gas saturation, oil saturation [17]. Special attention should be paid to the calculation of lithofacies segmentation based on available well data. Many manuals have been written on the construction of a three-dimensional model of the reservoir, as well as lithofacies interpretation of geophysical and core data, which allow sufficiently accurate reproduction of the available data in three-dimensional space [18–20].

The next stage substantiates the importance of reliable distribution of lithofacies properties over the reservoir [21, 22]. Using a comprehensive approach, the volume of each facies within the reservoir is determined using advanced geostatistical methods integrated into 3D modeling software [23, 24]. The kriging method [25–27], a reliable deterministic interpolation technique, is used together with the variogram method [28, 29], which estimates the spatial correlation of parameters. These methods are instrumental for analyzing and predicting the distribution of facies volumes across the reservoir. Using their synergy within the modeling software, this step provides an accurate and detailed characterization of the volumetric distribution of each facies, contributing to a complete understanding of the reservoir.

In the final step, the methodology combines volumetric facies data obtained using advanced geostatistical techniques to determine the average oil recovery rate during reservoir flooding. It is possible to calculate the average oil recovery rate for the reservoir, taking into account the volume of each facies, using the following formulas:

$$v=\frac{V}{V_f},$$

$$\overline{RF}=\sum_{i=1}^{n} RF_i \cdot v_i,$$

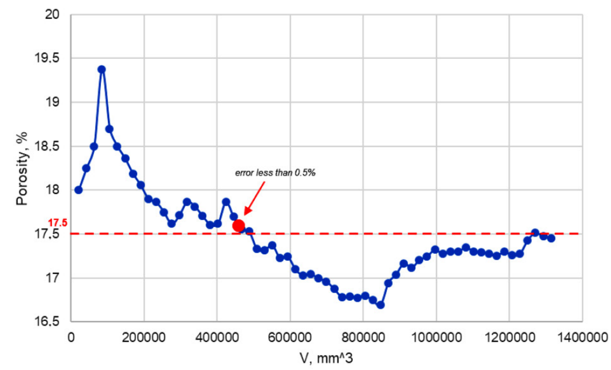
where $\overline{RF}$ – average value of the oil recovery coefficient for the reservoir; v – volume fraction of the facies in the rock; V – reservoir volume, m^3; V_f – volume of the studied facies in the formation, m^3.

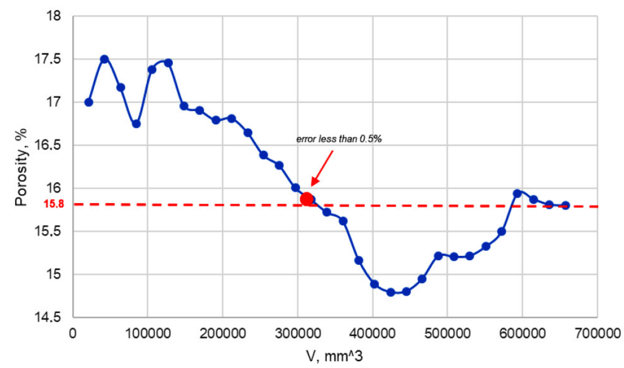
Given the specific facies distribution in the reservoir, this step provides a more refined assessment of how various geological characteristics affect the efficiency of oil recovery processes. The calculated average oil recovery, enriched with spatial data, offers a complete understanding of reservoir behavior under flooding conditions, aiding in strategic decision-making to optimize hydrocarbon recovery.

3. Results and Discussion

The methodology proposed in this study was tested on the example of the «Ukrainian Field», on the B-16n horizon, which belongs to the oil and gas condensate field. According to the data of geophysical studies and the core of the studied layer B-16n, the following facies classification is distinguished: sandstone, clayey sandstone, and siltstone. Next, the maximum available volume of porosity data was separated by lithological affiliation. For facies of sand, clayey sandstone, and siltstone, the number of porosity values is 62, 31, and 54, respectively. Based on the available number of values, the representative elementary volume (*REV*) was calculated in Fig. 1.

The red point in Fig. 1 means that with a given number of samples, the error of the average arithmetic value of porosity reaches a value of less than 0.5 %. The minimum required number of samples for a representative display of porosity for sandstone, clayey sandstone, and siltstone is 22, 15, and 25, respectively. This allows to use this number of samples for laboratory determination of the averaged values of each facies of irreducible water saturation.





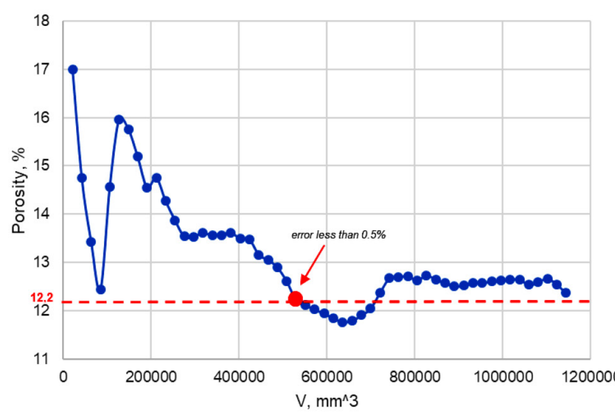


Fig. 1. Representative elementary volume (*REV*): *a* – sandstone; *b* – clayey sandstone; *c* – siltstone

According to the industry standard of Ukraine GSTU 41-00032626-00-025-2000 to determine the coefficient of irreducible water saturation of rocks using measurements by centrifugation of samples for each facies, graphs of water saturation of rocks at different displacement pressures under surface conditions were constructed (Fig. 2).

The value of coefficients of irreducible water saturation of each facies sandstone, clayey sandstone, and siltstone reduced to reservoir conditions is 12.31; 17.61; and 35.23, respectively.

Based on the values of irreducible water saturation and wettability of the samples, a relative permeability curve corresponding to each facies was generated in Petrel software (Fig. 3).

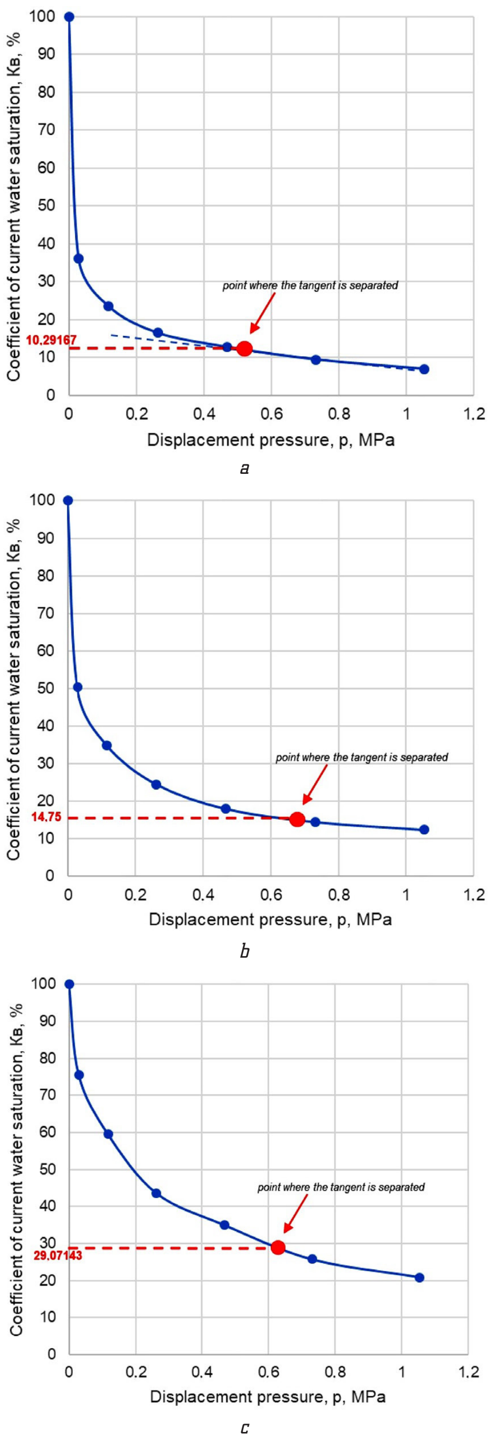


Fig. 2. Capillary pressure curve of averaged values of current water saturation versus displacement pressure for facies: *a* – sandstone; *b* – clayey sandstone; *c* – siltstone

Fractional flow curves were calculated and constructed based on the obtained data of relative permeability curves (Fig. 4).

The red point on the graphs of fractional flow curves (Fig. 4) is the point of intersection of the tangent with the curve, which indicates the breakthrough of water during flooding. Based on these graphs (Fig. 4), the coefficients of oil extraction were calculated for sandstone, clayey sandstone, and siltstone facies and are 0.53; 0.47; and 0.29, respectively.

Further calculation with the determination of the average oil recovery coefficient taking into account flooding requires the determination of the volume fraction of each facies in the formation. Such a calculation *can be carried out only under the condition* of three-dimensional modeling of the formation taking into account all seismic, geophysical, core data with subsequent lithological dissection.

Using advanced geostatistical techniques, kriging and variograms are seamlessly integrated into 3D modeling software to determine the volume distribution of each facie in the reservoir. This key step involves a precise spatial analysis that allows the volumes of individual facies to be quantified. The kriging method helps in deterministic interpolation, while the variogram method provides insight into the spatial correlation, together improving reservoir characterization for a better understanding of the oil recovery process.

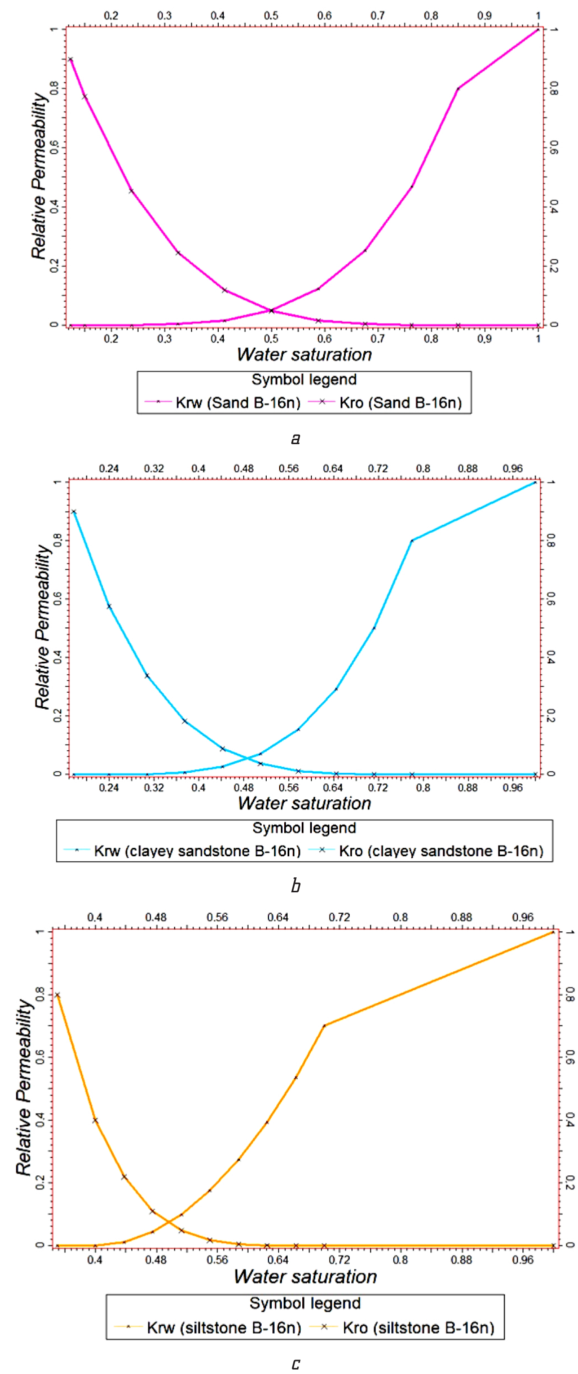


Fig. 3. Generated relative permeability curves for facies: *a* – sandstone; *b* – clayey sandstone; *c* – siltstone

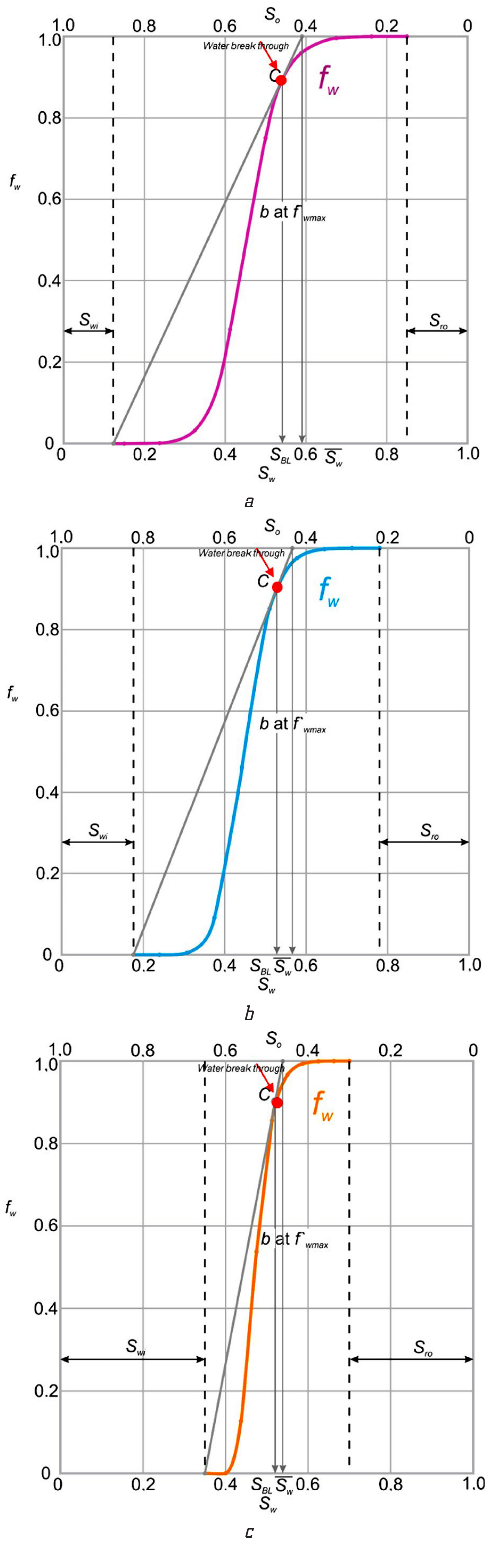


Fig. 4. Fractional flow curves for facies:
a – sandstone; *b* – clayey sandstone; *c* – siltstone

The obtained volumes of facies provide a detailed view of the heterogeneous structure of the formation, providing valuable information for the next stages of the methodology, in particular for the assessment of the dynamics of oil recovery.

The limitation of this research is the use of the proposed method exclusively for calculating the oil recovery coefficient during flooding.

A promising direction of the development of this research is an applied comparative analysis of the traditional and updated methods of estimating oil recovery coefficients, namely, a comparison of design solutions, forecast production based on a three-dimensional hydrodynamic model of the reservoir with the actual history of the development of the experimental field. This is due to the fact that the proposed innovations require careful verification before guidelines for state standards are developed based on them.

The conditions of martial law in Ukraine did not affect the conduct of the research and the results obtained.

4. Conclusions

In summary, the present study reveals an innovative methodology for estimating oil recovery by combining key elements such as *REV*, relative permeabilities, fractional flow curves, and flooding oil recovery. This comprehensive approach eliminates key limitations of existing methods, such as averaging properties over the reservoir, lack of lithofacies dissection, and ignoring relative permeability measurements, offering a more accurate and reliable definition of reservoir properties.

This comprehensive study includes laboratory-determined oil recovery coefficients for sandstone, clayey sandstone, and siltstone facies, which are 0.53; 0.47; and 0.29, respectively. Further actions require a close integration of the obtained data in three-dimensional space, as they allow to calculate the share of facies content in the reservoir volume.

By integrating advanced techniques in three-dimensional space, such as kriging and variograms, the limitations of traditional approaches are overcomed. A detailed analysis of the lithological distribution and facies properties increases the accuracy of our estimates. This method, supported by basic laboratory results, not only marks a significant advance in reservoir research but also lays the foundation for more accurate and reliable predictions of oil recovery in complex reservoirs.

Conflict of interest

The authors declare that they have no conflict of interest in relation to this research, whether financial, personal, authorship or otherwise, that could affect the research and its results presented in this paper.

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Data availability

The manuscript has no associated data.

Use of artificial intelligence

The authors confirm that they did not use artificial intelligence technologies when creating the current work.

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