Comparison of the Porosity Parameter in Sediments Obtained Using Traditional and Precision Methods (Cenomanian Deposits in Western Siberia, Russia)

Vitaliya Naumenko[1], Mikhail Zavatskij[2], Daniil Skudar[3]

[1,3] Laboratory for Workover Technologies and Well Stimulation, Tyumen Industrial University, Russia

[2] Department of Oil and Gas Deposits Geology, Tyumen Industrial University, Russia

https://doi.org/10.58429/qaj.v3n4a170

Abstract

The study focuses on porosity, an important parameter for calculating reserves. Traditionally, weight-based methods are used in calculation, which implies a simple approach to estimating hydrocarbon reserves. However, this study is based on the need to show that effective reserve assessment and hydrocarbon production planning require a combination of various methods supplemented by dynamic modeling. The Cenomanian deposit of the Yamburgskoe and Yubileynoe deposits in Western Siberia, Russia is the object of the study. A comparison is made based on the data obtained during the direct analysis using Preobrazhensky's method and microtomography of the core of the Cenomanian deposit. The study is carried out to evaluate the representativeness of various methods of measuring porosity and to investigate directly the reservoir of the Cenomanian deposit

Keywords: porosity, core sample, X-Ray tomography, gas, Cenomanian

1. INTRODUCTION

The porosity parameter is used in basin, geological, and hydrodynamic modeling and as input data for the assessment of reserves and the development of the hydrocarbon (HC) production process (Majd & Hezarkhani, 2011; Selley & Sonnenberg, 2023).

Information for assessing the structure and economic prospects of deposits, due to the complexities of geological systems and a variety of factors influencing them, is obtained from various sources, including geophysical studies (Potylitsyn et al. 2020), core studies, and thin section analysis (Tikhomirova & Mishchenko, 2021; Vasiliev et al. 2020). As a rule, laboratory core studies are the main reliable source of porosity data (Saemi et al. 2007). However, inhomogeneities in core samples affect the accuracy of laboratory measurements. Allshorn et al. (2019) experimentally showed that computer tomography (CT) scanning can identify any inclusions so that they can be considered when determining porosity.

Putilov et al. (2016) indicate that it does not matter whether the core is full- or standard-sized (in the case of terrigenous deposits with a pore type of voids), for example, concerning the filtration of reservoir fluids. However, Kuzhel et al. (2004) mention the concept of the scale effect, which

describes the dependence of obtaining different coefficients of open porosity on different sizes of the samples under study. Khasanov and Lonshakov (2020) consider the large-scale effect of rocks when measuring porosity, develop their sampling methodology, and conclude that the liquid saturation method is the most informative when measuring the porosity parameter since it allows studying larger samples and individual core intervals. Korost et al. (2009) state that the determination of porosity refers to the main tasks of geophysical well logging (GWL) (Katanov et al. 2021). However, Veliev (2019) points out the existence of many examples of significant errors when making such calculations, which ultimately affects the determination of their filtration-capacitance properties, oil recovery coefficient, and recoverable reserves.

1.1 Porosity Determination Methods

Sungatullin et al. (2017) state that the combination of traditional and precision methods for determining porosity coefficients allows for more accurate calculations affecting the calculation of reserves.

In laboratories, so-called weight-based methods are often used to measure open porosity. One of these is the method developed by I.A. Preobrazhensky.

Preobrazhensky's method uses the masses of a dry rock sample in the air, a sample saturated with kerosene in kerosene, and a sample with kerosene in the air and the density of kerosene to determine the porosity coefficient of the rock (Veliev, 2019).

X-ray computed microtomography (MCT) is an up-to-date and actively developing technique for determining the petrophysical properties of rocks. This method allows for detailed studies of rock inhomogeneities necessary for the development of reliable models of filtration and reservoir properties of HC deposits (Galkin et al. 2015).

MCT is used to form 3D images and observe the geometry of the pore space in samples. Visualization is performed using a microfocused X-ray tube, which receives shadow images of an object transmitted by several X-rays at different angles. Cross sections are extracted from them, and the object is reconstructed digitally (Silva et al. 2023). The CT system is described in detail by Ketcham and Carlson (2001).

X-ray MCT has become an important method to study the pore space of a porous medium. This method allows determining the porosity of fractured, cavernous, and granular rocks and visualize their texture, including voids, cavities, cracks, and mineral inclusions, due to the high contrast between the solid phase and the atmosphere (Krivoshchekov & Kochnev, 2013; Savitsky, 2015).

1.2 Background

The Cenomanian deposits are the largest gas reserves in Russia. Deposits such as Medvezhye, Yamburgskoye, Urengoyskoye, Yubileynoye, and others in the Nadym-Purskaya oil and gas-bearing region in the north of Western Siberia account for about 60% of all gas production in Russia (Shilov, 2010). However, gas withdrawals are now moving beyond the 80% mark, which is why there is a drop in reservoir pressure. The share of low-pressure gas is growing as production becomes unprofitable. Sarancha and Sarancha (2014) and Kusov and Savenok (2020) consider in detail the definitions of low-pressure gas, covering economic, technical, and social aspects. Since the reserves of such gas are large, attention is now drawn to their development. Sarancha et al. (2015) and Zakirov et al. (2004) indicate the importance of creating new technological approaches for the development of the Cenomanian gas deposits.

The work aims to measure the porosity of core samples of the Cenomanian deposits using MCT and liquid saturation methods.

2. MATERIALS AND METHODS

Core samples from the Yamburgskoe and Yubileynoe deposits were collected for the study. Information about the sampling is presented in Table 1.

Table 1. Sample Data for Analysis

No.	Deposit	Well	Selection interval, m	Sample No.
1	Yamburgskoe	24803	1,160.0-1,174.0	4.1
			1,174.0-1,188.0	106.31
			1,188.0-1,201.0	166.31
			1,201.0-1,210.0	176.31
2	Yubileynoe	2002	1,622.0-1,630.0	22.1
			1,730.0-1,742.0	39.1
			1,805.0-1,812.0	52
			1,816.50-1,821.50	80

Since the core is provided for relatively new wells, data on the calculation of reserves are not publicly available in geological funds. Therefore, porosity maps for the Yamburgskoe and Yubileynoe deposits from the 2011 and 2009 reserve calculations, respectively, were taken as a basis. The positions of the studied wells relative to those on the maps were copied from the well location maps and marked accordingly (Figures 1 and 2).
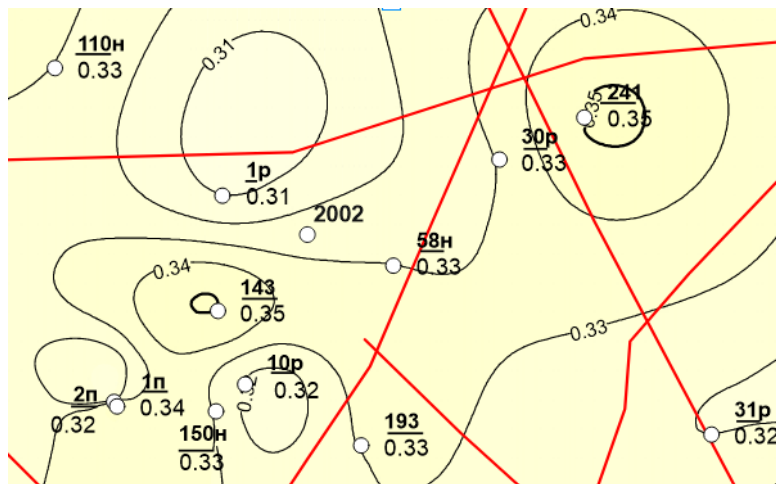
Fig. 1. Map of the average porosity of the gas-saturated part of the Cenomanian deposit of the Yubileynoe deposit (with added Well 2002)
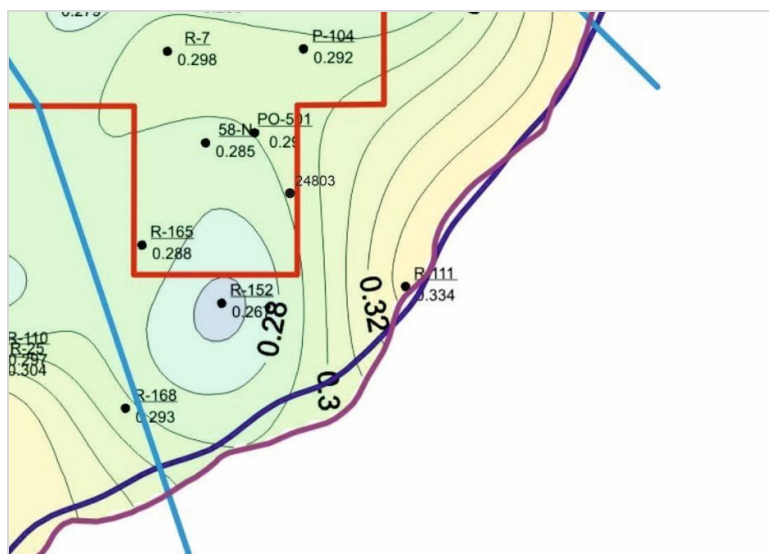

Fig. 2. Map of the average porosity of the gas-saturated part of the Cenomanian deposit of the Yamburgskoye deposit (with added Well 24803)

Based on the map values, Well 2002 of the Yubileynoe deposit is located at a point with a porosity value of about 0.325, and Well 24803 of the Yamburgskoye deposit at a value of 0.291.

2.1 Experimental Methods

Preobrazhensky's method

The sequence of work (described in detail by Ivanitsky (2018)):

- The samples (pre-extracted and dried at 105°C to a constant mass) were weighed in the air to determine M1 (the mass of a dry, clean rock sample in the air). For subsequent weighing in liquid, a wire with a loop at the end was tied to the sample so as not to consider its mass in further calculations.

- Then the sample was treated in a vacuum separately with kerosene until the release of air bubbles completely stopped (within 30-40 minutes). After that, it was slowly immersed in

vacuumed kerosene, raising the liquid level in steps so that saturation occurred mainly due to capillary intake. Vacuuming in kerosene lasted 10-20 minutes. At the end of it, the vacuum pump was turned off, the tap was slowly opened and the cuvette with the samples was removed. Before the measurements, the samples were kept under the liquid level so that there was no contact with the atmosphere.

- After the end of the saturation and re-saturation process, the samples were weighed hydrostatically, determining the mass of the sample immersed in liquid, M2 (the mass of the kerosene-saturated rock sample in kerosene).

- After hydrostatic weighing was completed, the saturated samples were weighed in the air to determine M3.

The porosity of the sample was determined based on the formula:

$$K_P = \frac{M_3 - M_1}{M_3 - M_2} * 100$$

(1)

where M1 is the mass of a dry rock sample, g; M2 is the mass of a liquid-saturated rock sample in the saturating liquid, g; M3 is the mass of the sample saturated with liquid in the air, g.

Porosity is a basic parameter when estimating HC reserves. The results of laboratory studies of core samples were the petrophysical basis for the interpretation of GWL. The only governing document in force in Russia that describes the requirements for determining porosity is State Standard (GOST) 26450.1-85 Mountain rocks. Method for determining the coefficient of open porosity using liquid saturation (Gilmanov, 2021).

2.2 Determination of Porosity Using Microtomography

The digital core models were taken on a computer X-ray microtomograph SkyScan 1172. With the help of specialized NRecon software, reconstruction was carried out and subsequent analysis was performed in the software packages CTan, DataViewer, and CTVox.

The settings for scanning and reconstruction and related additional materials for core samples were selected based on the task. The objective of the study was to identify lithological heterogeneities and technogenic fracturing. The scanning and reconstruction settings for all samples were the same: Image Pixel Size (um)= 26.69; Filter=Al+Cu; Exposure (ms)= 2000; Rotation Step (deg)=1.000; Frame Averaging=ON (2); Random Movement=ON (20); Use 360 Rotation=YES; Smoothing=3; Smoothing kernel=2 (Gaussian); Ring Artifact Correction=20; Draw Scales=OFF; Beam Hardening Correction (%)=0; Minimum for CS to Image Conversion=0.000000; Maximum for CS to Image Conversion=0.030000.

3. RESULTS

3.1 Values According to the Preobrazhensky Method

Table 2. Results of Analysis Using the Preobrazhensky Method Based on Samples from the Yamburgskoye Deposit

Yamburgskoe				
Sample	M1	M2	M3	Porosity, %
4.1	46.185	19.842	52.588	19.55
106.31	46.843	19.54	53.013	18.43
166.31	45.563	18.135	51.652	18.17
176.31	49.999	20.362	55.527	15.72

Table 3. Results of Analysis Using the Preobrazhensky Method Based on Samples from the Yubileynoe Deposit

Yubileynoe				
Sample	M1	M2	M3	Porosity, %
22.1	37.634	14.8	41.82	15.5
39.1	42.005	16.123	45.99	13.34
52	41.419	16.376	45.823	14.86
80	40.63	16.163	44.902	14.95

3.2 Values According to core MCT Data
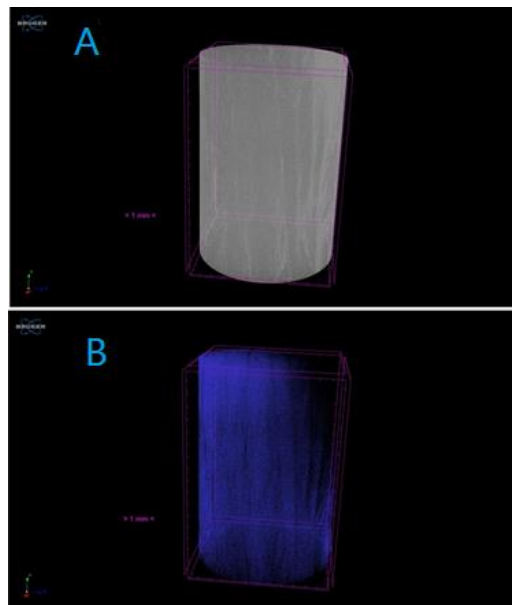
The results are shown in Figures 3-10.

Fig. 3. 3D models of Sample 4.1: A: lithological inhomogeneities; B: the void space structure
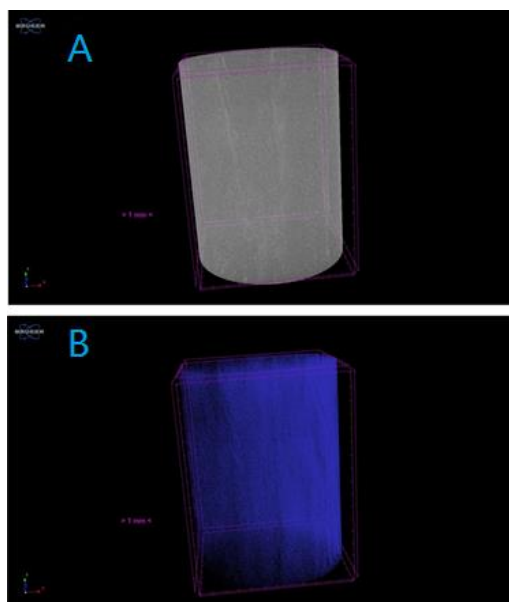
Fig. 4. 3D models of Sample 106.31: A: lithological inhomogeneities; B: the void space structure
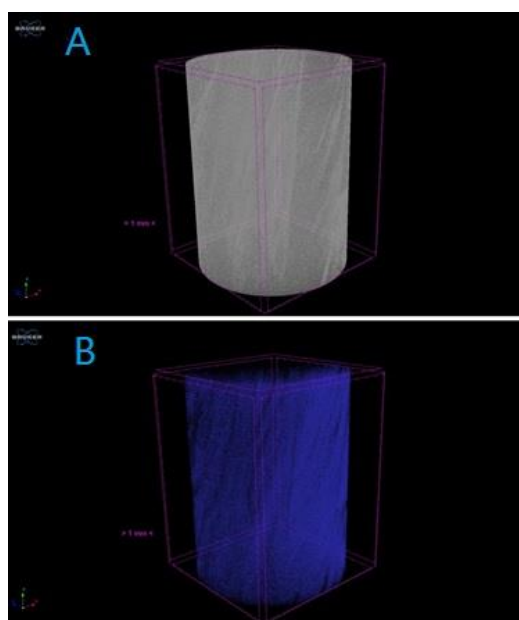

Fig. 5. 3D models of Sample 166.31: A: lithological inhomogeneities; B: the void space structure
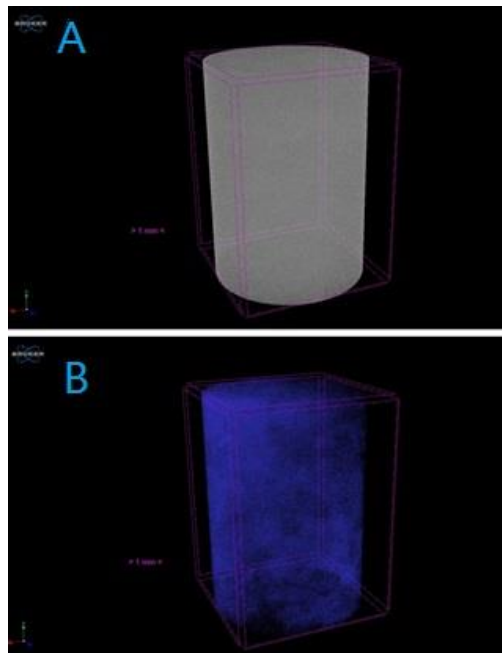
Fig. 6. 3D models of Sample 176.31: A: lithological inhomogeneities; B: the void space structure

Based on the results of visual analysis of 3D models (lithological inhomogeneities and the void space structure) of the studied samples of the Yamburgskoye deposit, we can conclude the following:

1: Samples 4.1, 106.31, and 166.31 are lithologically heterogeneous, as evidenced by the oblique layering of clay impermeable interlayers reflected in the complex geometry of the void space.

2: In Sample 176.31, clay impermeable interlayers are absent, but the void space structure is spotted. This is due to the complex lithological structure and the interlayer of sand and siltstone fractions. Within the resolution of the survey, we managed to visualize the voids of the sand fraction. The small pores of the siltstone fraction go beyond the resolution, but this does not indicate their zero permeability.
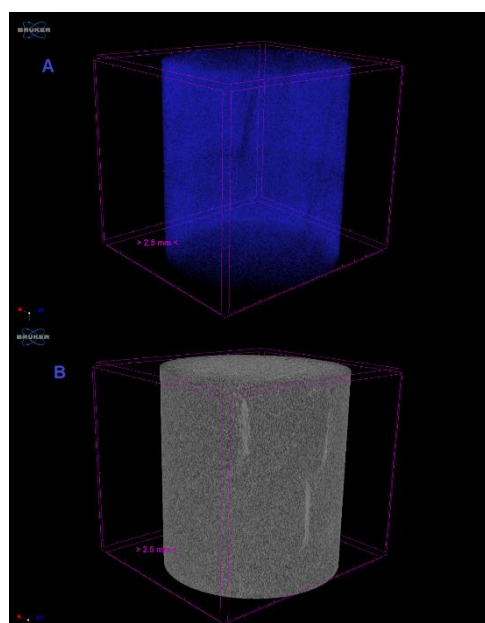

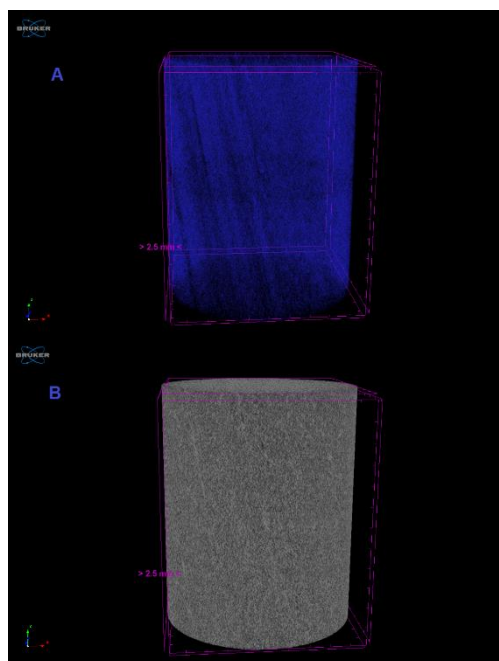**Fig. 7.** 3D models of Sample 22.1: A: the void space structure; B: lithological inhomogeneities

Fig. 8. 3D models of Sample 39.1: A: the void space structure; B: lithological inhomogeneities
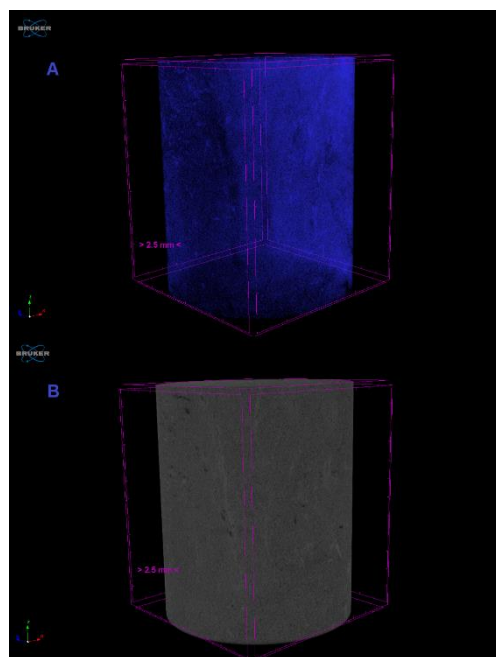

Fig. 9. 3D models of Sample 52: A: the void space structure; B: lithological inhomogeneities
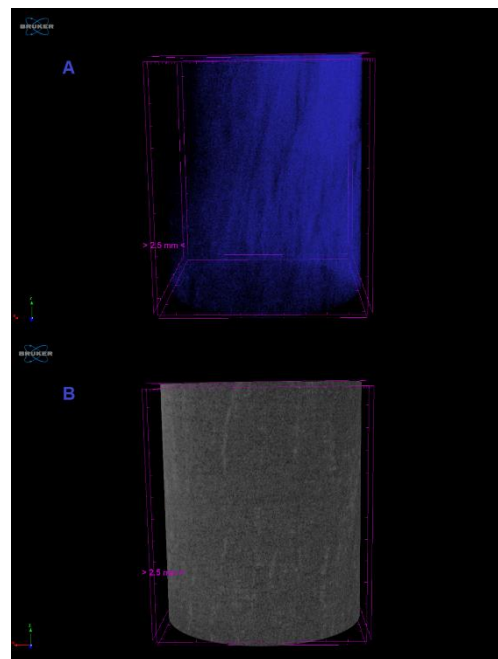
Fig. 10. 3D models of Sample 80: A: the void space structure; B: lithological inhomogeneities

Visual analysis of the samples of the Yubileynoe deposit showed the following:

1: There is pronounced oblique layering, most pronounced in Samples 22.1, 39.1, and 80.

2: In general, the structure of the samples is heterogeneous, characterized by the layering of sandy, siltstone, and clay fractions.

These heterogeneities should first of all be considered from the side of the variability of the permeability and porosity (PP) because this is most important. The visualized 3D sample models show that despite the pronounced micro-heterogeneity, the sand fraction prevails. The open porosity is high and the variability of lithology persists throughout the productive formation.

The measurement results are presented in Table 4.

Table 4. Results of MCT Analysis Based on Samples from the Yubileynoe and Yamburgskoye Deposits

Yamburgskoe		Yubileynoe	
Sample	Porosity, %	Sample	Porosity, %
4.1	18.5	22.1	13.37
106.31	19.91	39.1	10.5
166.31	19.5	52	12.38
176.31	13.46	80	14.05

4. DISCUSSION

As the study results show, the weight methods give only a static picture of the reservoir based on the data available at a specific time. In many cases, especially in old deposits or in regions with limited

exploration, data may be scarce, outdated, or of poor quality. This can lead to uncertainty and both overestimation and underestimation of reserves (Firsova et al. 2019; Ilyushin&Afanaseva, 2020).

Weight-based methods often assume that reservoir properties, such as porosity and saturation, are uniform throughout. In reality, reservoirs may exhibit significant heterogeneity, which may affect the assessment of reserves (Tolmachev et al. 2020; Panikarovskiy et al. 2021). In our study, we confirmed these conclusions by measuring the porosity of core samples of the Cenomanian deposits using MCT and liquid saturation methods.

The results of porosity measurement using Preobrazhensky's and MCT methods show an average discrepancy of 13.3% in the direction of increase in the case of Preobrazhensky's method. However, Samples 160.31 and 166.31 from the Yamburgskoye deposit, according to MCT data, showed a result 7-8% higher than the measurement using the alternative method. The calculations were carried out as a percentage, whereas the porosity coefficient has no units of measurement. However, the measured values differ from the accepted values (based on the maps in Figures 1 and 2) by about 1.5 times downwards. This may be due to both a small sample and analysis of only four samples, as well as a noticeable overestimation of porosity values in the calculations for calculating reserves. These errors are mentioned by Ponomarev et al. (Ponomarev et al. 2021) since laboratory studies are not sufficient. As a rule, dependencies with GWL are determined (Yesmagulova et al. 2023) and average calculation parameters are taken, which further increases the percentage of error in determining the filtration-capacitance properties of formations.

5. CONCLUSIONS

The results of the conducted studies show low porosity values for both deposits, as well as lithological and mineralogical variability and pronounced oblique layering characteristic of all samples without exception.

Limitations of the study: in the comparative characterization of porosity estimated using MCT and standard methods, it is important that part of the pores remained beyond the resolution of the survey. Besides that, we used the latest data on wells publicly available.

In the future, we plan to improve the efficiency of reserve assessment and HC production planning using a combination of various methods supplemented by dynamic reservoir modeling and economic estimates.

by the Center for Shared Use of Scientific Equipment "Center for Advanced Research & Innovative Developments" (Tyumen Industrial University, Tyumen).

REFERENCES

Majd, M. T., Hezarkhani, A. (2011). Estimation of Spatial Distribution of Porosity by Using Neural Networks Method in One of Oil Fields in South of IRAN. *Australian Journal of Basic and Applied Sciences*, 5(8), 182–189.

Selley, R. C., Sonnenberg, S. A. (2023). The Reservoir. *In Elements of Petroleum Geology (4th ed.)*. 275–359. doi: 10.1016/B978-0-12-822316-1.00006-9

Potylitsyn, V., Kudinov, D., Kokhankova, E., Shaydurov, G. (2020). The Results of Observing the Seismoelectric Effect in a Gas Condensate Hydrocarbon Field Using a Source of Seismic Field. *International Journal of GEOMATE*, 20(77), 33–39. doi: 10.21660/2020.77.62979

Tikhomirova, E. A., Mishchenko, K. P. (2021). Estimation of Parameter Uncertainty for Hydrocarbon Reserves Estimation. Bulletin of TvGU. *Series: Geography and Geoecology*, 1(33), 35–41.

Vasiliev, E. R., Zakieva, R. R., Petrov, S. M., Kantyukov, R. R., Shenkarenko, S. V. (2020). Transformations of Oil Hydrocarbons in Aqueous Fluids: Aquatermolysis in Subcritical and Supercritical Water. *ARPN Journal of Engineering and Applied Sciences*, 15(15), 1672–1677.

Saemi, M., Ahmadi, M., Varjani, A. Y. (2007). Design of Neural Networks Using Genetic Algorithm for the Permeability Estimation of the Reservoir. Journal of Petroleum Science and Engineering, 59(1–2), 97–105. doi: 10.1016/j.petrol.2007.03.007

Allshorn, S. L., Dawe, R. A., Grattoni, C. A. (2019). Implication of Heterogeneities on Core Porosity Measurements. Journal of Petroleum Science and Engineering, 174, 486–494. doi: 10.1016/j.petrol.2018.11.045

Putilov, I. S., Rekhachev, P. N., Gurbatova, I. P., Barkovskii, N. N., Iakimov, O. I., Moroziuk, O. A. (2016). Full-Size Core Epoch at Laboratory Research of Eor Technologies. *Bulletin of PNRPU. Geology. Oil & Gas Engineering & Mining*, 15(19), 155–164. doi: 10.15593/2224-9923/2016.19.6

Kuzhel, S. V., Sdvizhkova, E. A., Shashenko, A. N. (2004). Scale Effect in Rocks. *Donetsk: Nord Press*.

Khasanov, D. I., Lonshakov, M. A. (2020). Investigation of the Scale Effect and the Concept of a Representative Volume Element of Rocks in Relation to Porosity. *Georesources*, 22(4), 55–69. doi: 10.18599/grs.2020.4.55-69

Korost, D. V., Kalmykov, G. A., Reshetov, E. V., Blokhin, V. S. (2009). Petrophysical Support for the Interpretation of a Complex of Geophysical Surveys of Wells Based on Spectrometric Gamma Ray Logging. *Bulletin of Moscow University. Series 4. Geology*, 2, 68–74.

Katanov, Y., Vaganov, Y., Cheymetov, M. (2021). Neural Simulation-Based Analysis of the Well Wall Stability while Productive Seam Penetrating. *Mining of Mineral Deposits*, 15(4), 91–98. doi: 10.33271/MINING15.04.091

Veliev, R. G. (2019). Determination of the Porosity Coefficient of Rocks of a Productive Hydrocarbon Reservoir. *Nauchnyye Dostizheniya i Otkrytiya 2019: Collection of Articles of IX International Research Contest: in 2 parts, Part 1*. 50–55

Sungatullin, R. Kh., Islamova, R. R., Kadyrov, R. I., Sungatullina, G. M. (2017). Traditional and Precision Methods for Studying the Pore Space of Oil Reservoirs. *Petroleum Economy*, 11, 89–91. doi: 10.24887/0028-2448-2017-11-89-91

Galkin, S. V., Efimov, A. A., Krivoshchekov, S. N., Savitskiy, Ya. V., Cherepanov, S. S. (2015). X-Ray Tomography in Petrophysical Studies of Core Samples from Oil and Gas Fields. *Russian Geology and Geophysics*, 56(5), 782–792. doi: 10.1016/j.rgg.2015.04.009

da Silva, M. T. Q. S., Perretto, F., Cardoso, M. do Rocio, Mazer, W. (2023). Porosity: Some Characterization Techniques. *Materials Today: Proceedings*. doi: 10.1016/j.matpr.2023.03.716

Ketcham, R. A., Carlson, W. D. (2001). Acquisition, Optimization and Interpretation of X-Ray Computed Tomographic Imagery: Applications to the Geosciences. *Computers & Geosciences*, 27(4), 381–400. doi: 10.1016/S0098-3004(00)00116-3

Krivoshchekov, S. N., Kochnev, A. A. (2013). Application Experience of Computed Tomography to Study the Properties of Rocks. *Bulletin of PNRPU. Geology. Oil & Gas Engineering & Mining*, 6, 32–42.

Savitsky, Y. V. (2015). Modern Capabilities of the X-Ray Tomography Method in the Study of Core Oil and Gas Fields. *Bulletin of PNRPU. Geology. Oil & Gas Engineering & Mining*, 15, 28–37. doi: 10.15593/2224-9923/2015.15.4

Shilov, G. Y. (2010). Geological Aspects of Pore Pressure Assessment in Well Sections Based on Geophysical Data. *Moscow: Gazprom expo*.

Sarancha, A. V., Sarancha, I. S. (2014). Low-Pressure Gas of the Cenomanian Deposits of the Yamal-Nenets Autonomous Okrug. *Academic Journal of Western Siberia*, 10(3(52)), 146–147.

Kusov, G. V., Savenok, O. V. (2020). Low-Pressure Petroleum Gas: Volumes of Production and Complications Arising During Its Collection and Preparation. *Bulatov Readings*, 4, 69–76.

Sarancha, A. V., Sarancha, I. S., Mitrofanov, D. A., Ovezova, S. M. (2015). Technologies for Production of Low-Pressure Cenomanian Gas. *Modern Problems of Science and Education*, 1–1, 211.

Zakirov, S. N., Zakirov, E. S., Zakirov, I. S., Baganova, M. N., Spiridonov, A. V. (2004). New Principles and Technologies of Oil and Gas Field Development. *Moscow: Institute of Oil and Gas Problems of the Russian Academy of Sciences*.

Ivanitsky, A. V. (2018). Determination of the Open Porosity Coefficient of Rocks Using the Liquid-Saturation Method and the Gas-Volumemetric Method. *Alley of Science*, 2(7(23)), 227–231.

Gilmanov, Y. I. (2021). Assessment of the Capacitive Space of the Berezovsky Formation Using Modern Laboratory Methods. *News of Gas Science*, 1(46), 170–175.

Firsova, I. A., Vasbieva, D. G., Litvinov, A. V., Chernova, O. E., Telezhko, I. V. (2019). Trends in the Development of the Global Energy Market. *International Journal of Energy Economics and Policy*, 9(3), 59–65.

Ilyushin, Y., Afanaseva, O. (2020). Modeling of a Spatial Distributed Management System of a Preliminary Hydro-Cleaning Gasoline Steam Column. *In International Multidisciplinary Scientific GeoConference Surveying Geology and Mining Ecology Management, SGEM 2020*, 2.1, 531–538. doi: 10.5593/sgem2020/2.1/s08.068

Tolmachev, O., Urunov, A., Muminova, S., Dvoichenkova, G., Davydov, I. (2020). Review of Unconventional Hydrocarbon Resources: Production Technologies and Opportunities for Development. *Mining of Mineral Deposits*, 14(4), 113–121. doi: 10.33271/mining14.04.113

Panikarovskiy, E. V., Panikarovsky, V. V., Listak, M. V., Verkhovod, I. Y., Katanov, Y. E. (2021). Drilling Fluids for Drilling Wells at the Bovanenkovo Oil and Gas Condensate Field. *International Journal of Engineering Trends and Technology*, 69(12), 8–12. doi: 10.14445/22315381/IJETT-V69I12P202

Ponomarev, A. I., Merkulov, A. V., Sopnev, T. V., Murzalimov, Z. U., Kushch, I. I., Kozhukhar, R. L. (2021). Assessment of the Accuracy of Determining the Porosity Coefficient when Performing Three-Dimensional Geological Constructions. *News of Tomsk Polytechnic University. Georesources Engineering*, 332(4), 97–106.

Yesmagulova, B. Z., Assetova, A. Y., Tassanova, Z. B., Zhildikbaeva, A. N., Molzhigitova, D. K. (2023). Determination of the Degradation Degree of Pasture Lands in the West Kazakhstan Region Based on Monitoring Using Geoinformation Technologies. *Journal of Ecological Engineering*, 24(1), 179–187. doi: 10.12911/22998993/155167