Geosciences and Engineering, Vol. 8, No. 13 (2020), pp. 154–166.

FLOW RATE AND PERMEABILITY DETERMINATION IN ROCK SAMPLES FROM UNCONVENTIONAL RESERVOIRS – TO SUPPORT THE GEOPHYSICAL INVERSION MODEL

FERENC REMECZKI[1] – PÉTER NORBERT SZABÓ[2, 4] – MIHÁLY DOBRÓKA[3]

[1]*Research Institute of Applied Earth Sciences, University of Miskolc*
[2, 3]*Department of Geophysics, University of Miskolc*
[1]*afkremec@uni-miskolc.hu,* [2]*norbert.szabo.phd@gmail.com,* [3]*dobroka@uni-miskolc.hu*
[4]*MTA-ME Geoengineering Research Group, University of Miskolc*
3515 Miskolc-Egyetemváros, Hungary

Abstract: The purpose of the article is to introduce a deeper insight and understanding of unconventional hydrocarbon reservoir flow mechanisms through tight gas samples originating from a Hungarian formation. The paper describes problems that appear during the measurement protocol that was designed to provide strong support for the geophysical inversion model under development within the framework of the PULSE project and the possibilities for preserving the rock material while gaining as much information as possible.

Keywords: *unconventional reservoir, tight sandstone, flow rate*

1. INTRODUCTION

Several parallel research projects regarding unconventional hydrocarbon reservoirs are underway, still there is much to be uncovered. Selecting the proper measurement technique and protocol is not easy even under laboratory conditions, which results in undesired time loss or higher costs, and in-situ geophysical measurement implementation can further increase the expenses. Research groups of the PULSE project are working together at the University of Miskolc to develop a proper evaluation system for unconventional reservoirs that contains an appropriate measurement protocol as well as a geophysical inversion model. In this article the focus is on different parts of the measurement program development and the corrections which need be made to receive values suitable for evaluation.

During the research project, porosity determination is implemented by two different methods. Helium pycnometry is more common and faster if the API standard plug size is available. In our case, however, for tight sandstone samples, the measurement time is increased significantly compared to conventional sandstone samples. Another option to determine the porosity is mercury injection which can be performed on so-called 'small' samples with a volume of 1 to 2 cm^3. It is important to note that the measurements are not performed on the same specimen, thus their values can never exactly be the same [1]. The preparation procedure of the plug size and small samples is shown in *Figure 1*.

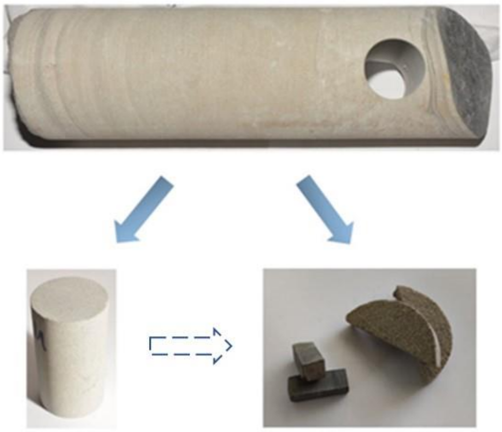

Figure 1

Sample preparation possibilities for different measurement types

Porosity results are available for all (currently 240) plug size specimens. *Figures 2* and 3 summarize the results of a measurement program compiled for samples originating from unconventional hydrocarbon reservoirs. Several rock types are investigated, including compacted sandstones, tuffs and marls as tight gas/shale reservoir samples. Preparation of the small samples required for mercury injection was not possible in all cases. There are plug size specimens on which other measurements will be performed, thus small sample preparation and the mercury injection measurement application will only be possible at a later stage of the program. The porosity values measured on API standard plugs by helium pycnometry are shown in *Figure 2*.

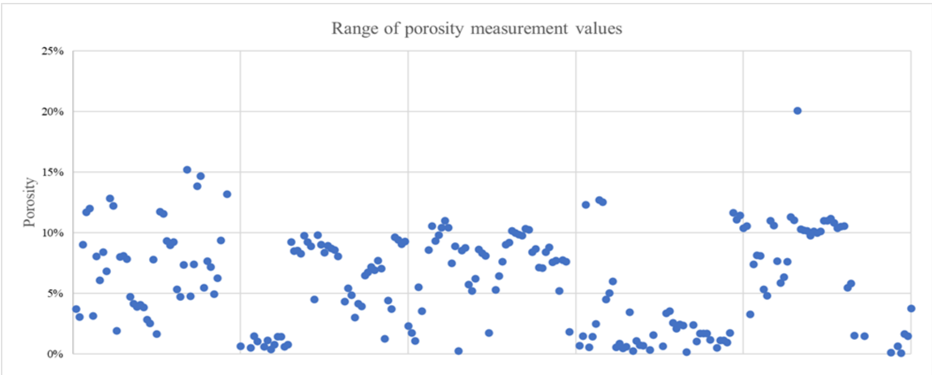

Figure 2

Results of helium pycnometry measurements carried out on tight gas and marl samples. The data series is filtered in alphabetic order of the signs of the samples.

A significant proportion of porosity values are below 10%. This value is under 5% for marl samples, although, it is important to mention that not every data lower than 5% belongs to marl specimens.

Permeability measurements were made with two instruments, both utilizing nitrogen gas. It must be noted that the measuring ranges of the two devices are different. The results of permeability measurements are shown in *Figure 3*.

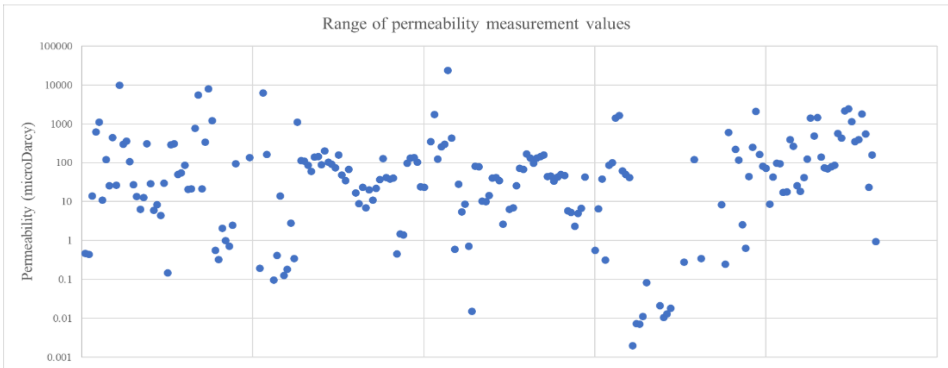

Figure 3

Results of permeability measurements made on tight gas and marl samples

It is also noteworthy that permeability values vary over a wide range of 7 orders of magnitude, from 1 nD to 10 mD.

2. Experiences during measurement program application

During the implementation of the measurement program performed on rock samples from unconventional reservoirs and the evaluation of the results, we found the following:

- Certain specimens with high similarity in other properties had significantly different permeability values. Furthermore, the pore size distributions from mercury injection measurements showed surprising differences in the ranges above 10 microns.
- In several cases, notable differences occurred at the 'border' of two measuring instruments. Samples fell outside the measurement range of the Nano-K, and a conventional device measured higher permeability by orders of magnitude.
- In many cases, visible cracks could be observed on the surface of the samples.

Based on the experience, we made the following findings:

- In addition to permeability measurements, the flow systems in the sample body should be examined based on the pore-throat distribution.
- If it is proven that the flow system is partially or fully beyond the validity of the Darcy flow, a correction must be applied.
- The core samples examined have been in the core depot for decades; they may have been damaged, in which case the resulting cracks are not part of the original rock sample and will bias the measurement results.

- Surface damage (microcracks) can occur during sample preparation, which can significantly increase the measured permeability.

In order to explore the causes and make the appropriate correction, we launched two parallel research programs. Microcracks and surface damage were detected by electron microscopy. The flow system formed in the sample body was investigated using the Javadpour theoretical model [2] based on the Knudsen number. Correction may be required for two different reasons:

- the flow system formed in the sample is not Darcy – type, or
- the microcracks in the sample body and on its surface significantly increases permeability.

3. Another approach in flow rate determination

The production experience of unconventional formations over the past decade has shown that the permeability values calculated using the Darcy relation are lower than actual values. Several authors have published solutions for the correction of Darcy permeability [2], [3]. Corrections for the slip flow region have been available for a long time. In practice, we determined the Knudsen number for the most frequent pore radius – MFPR – value of the sample and made corrections accordingly. Knudsen numbers and flow ranges for different pore throat diameter values under laboratory conditions (2.2 bar, 20 °C, N_2) are presented in *Figure 4*. It can be observed that the validity of Darcy flow is impaired from the 10-micron pore-throat range.

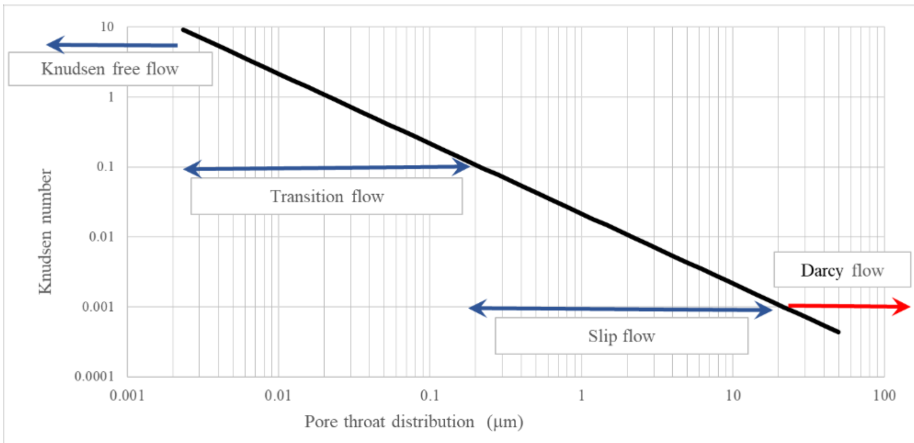

Figure 4
Flow type determination using Knudsen number as a function of pore throat distribution

For tight sandstones, MFPR is typically on the order of a tenth of a micron. As an illustration, *Figure 5* shows the MFPR data of the samples from Békés-5 well. Comparing *Figure 4* and *5,* we see that MFPR values are located at the boundary between slip and transition flow. Consequently, in case of the samples shown in *Figure 5*, it is justified to make a correction to the 'conventionally' calculated so-called Klinkenberg permeability.

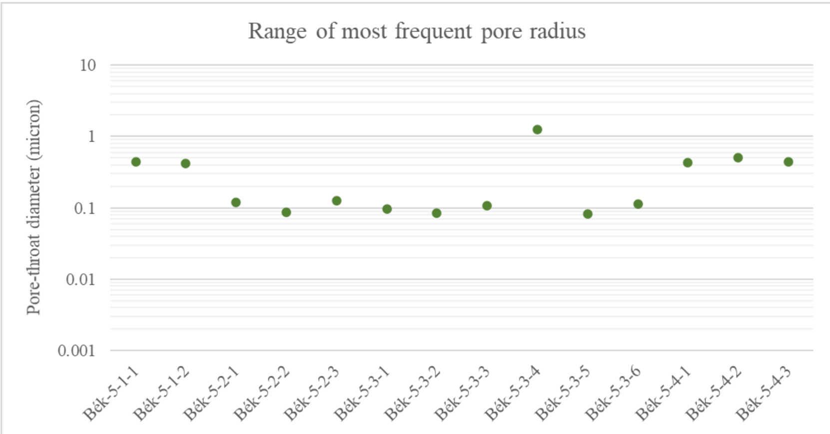

Figure 5
Most frequent pore throat radius values in tight sandstone samples

During further examination of the measurement conditions and data of the tight sandstone samples, we observed an interesting phenomenon which will be described below. The rock from drilling core no. 3 and its remnants after sample formation are shown in *Figure 6*.

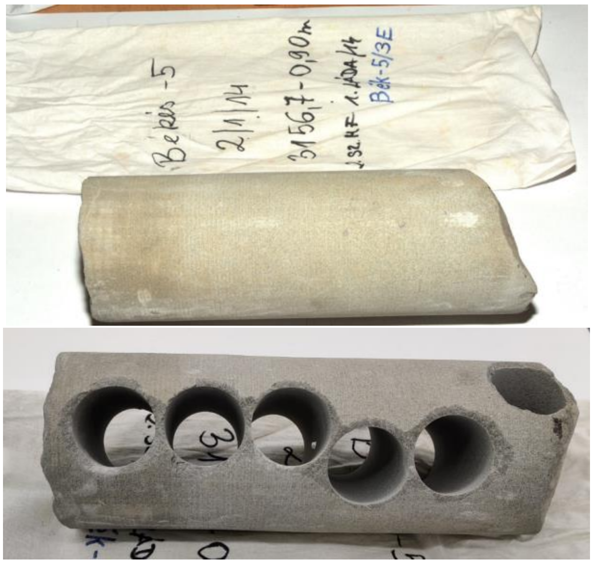

Figure 6
Bék-5/3 core part before and after sample preparation

Figure 7 shows the Klinkenberg permeability values of the plug size samples from Békés-5 well and samples from core no. 3 framed within it. It can be observed that the samples formed in the immediate vicinity of each other have immensely different permeabilities.

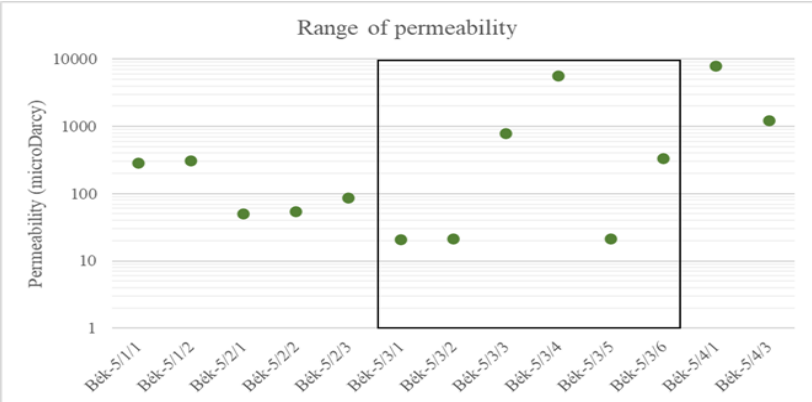

Figure 7

Permeability values distribution among samples prepared from Bék-5 drilling cores

We have examined the results of the most characteristic properties of mercury injection measurements – total porosity (TP), total cumulative Mercury volume (TCV), total specific surface area (TSSA) and average pore radius (APR) – performed on small samples belonging to the same plug size samples, which are illustrated in *Figure 8*.

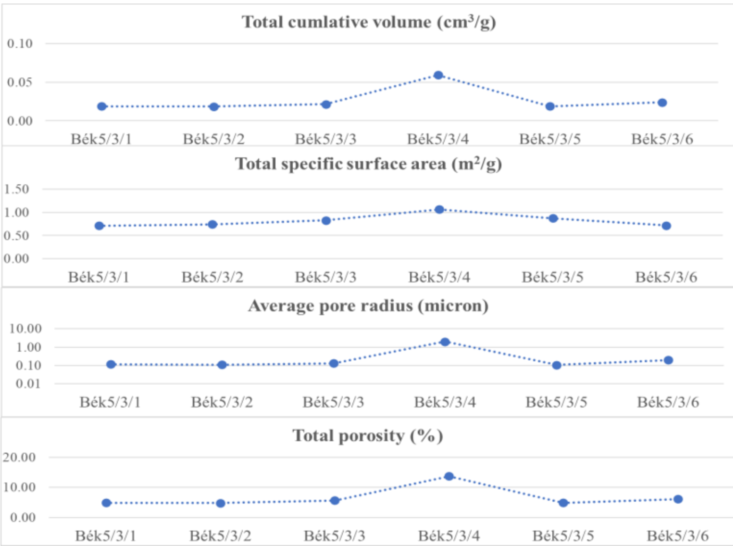

Figure 8

Result comparison of mercury injection measurements for samples prepared from Bék-5/3 drilling core

Table 1
Data table of mercury injection measurement results carried out on Bék-5/3 drilling core samples

Plug	Bék5/3/1	Bék5/3/2	Bék5/3/3	Bék5/3/4	Bék5/3/5	Bék5/3/6	Dimension
TCV	0.0188	0.0187	0.0217	0.0595	0.0190	0.0241	cm^3/g
TSSA	0.7120	0.7430	0.8260	1.0650	0.8720	0.7180	m^2/g
APR	0.1172	0.1091	0.1300	1.9896	0.1078	0.1969	μm
TP	4.9008	4.8309	5.6532	13.7295	4.9354	6.1125	%

Figure 8 and *Table 1* demonstrate well that the properties of small specimens close to each other, with one exception, show extreme similarity. It can therefore be assumed that the permeability values of samples with a pore space system showing such similarity should also be analogous.

3.1. Theoretical model application and results

For further investigation of the phenomenon, in case its existence is proved, we used the data of mercury injection measurements and the theoretical model of Javadpour [2]. Examination of the pore-throat distribution curves revealed that in the range above 10-micron diameter, the microcracks are not characteristics of the rock matrix, which significantly distorts permeability values. For a proper analysis to be carried out, theoretical 'model samples' were created from pore-throat distributions. The following was considered during the model creation:

- By default, 'laboratory' conditions (p, Δp, T), the gas (nitrogen) used in the 'simulation measurement' and the length of the samples are the same as the measurement conditions for the Nano-K permeameter.
- The pore space of the model sample is completely dry and extracted.
- The model assumes that the nature of the pore system (micro- and nanopores) allows the volume of the pore space to be considered unchanged in the form of a tubular network model consisting different tubes.

The flow in the pores is determined by the total mass flow flux (J), which is the sum of the pressure-controlled mass flow (advection) flux (J_a) and the Knudsen-type diffusion (J_D) flux. A more detailed presentation of the model is omitted here due to size limitations (see [4] for more details). The tube diameters of the model are derived from mercury injection measurements, and their quantitative distribution reflects the distribution histogram of the pore throats. The model sample is treated as a standard plug sample. The inflow surface, which means the sum of the inflow diameters of the tubes, is based on the porosity, so that the porosity values related to the volume are taken to be the same for each infinitesimally thin sample slice *(Figure 9).*

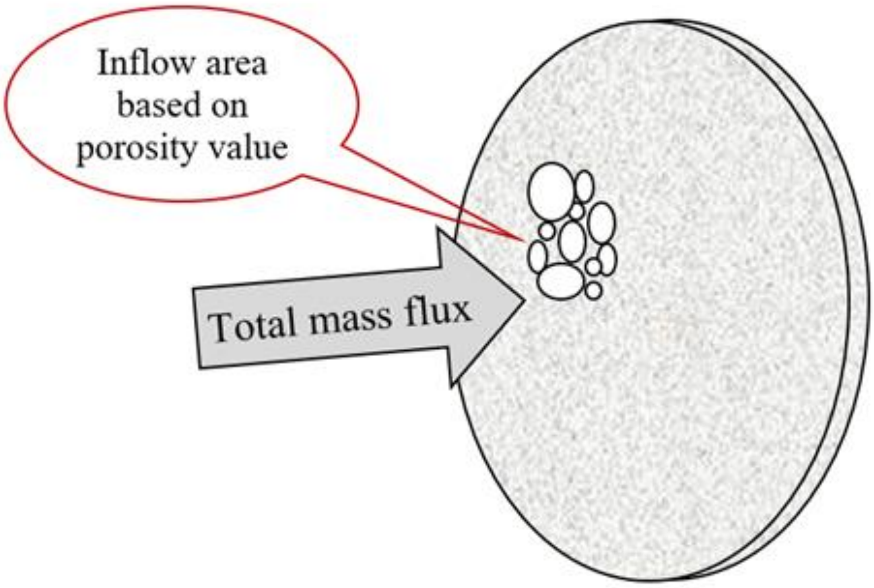

Figure 9
Slice of the theoretical model sample

During the simulated measurements, the following were determined for each pipe diameter:

- Knudsen number (Kn) (–),
- Knudsen diffusion constant (D_K) (m^2/s),
- theoretical dimensionless coefficient (F) (–),
- total mass flow flux (J) ($kg/s \cdot m^2$),
- flow rate (q) (m^3/s).

In case of the model samples, weighting the flow rates of 'tubes' with their volume ratio present in the sample, we get a clear representation of how the gas flow is distributed in the pores of different sizes. It is important to emphasize that, at this point, there is a possibility to eliminate microcracks. As was mentioned before, the microcracks are not part of the rock matrix, thus they should be removed from the model sample. This process, in case of unconventional samples, usually involves the range above 10 microns. In each case, an extremely careful procedure was made to examine the pore-throat distribution histograms. *Figure 10* shows the histograms of Bék-5/3/1 and Bék-5/3/2 samples and their magnified regions above 1 micron. In case of both samples, there are values in the range above 10 microns; especially in the Bék-5/3/2 sample quite high values can be observed, which should not be included in the sample model.

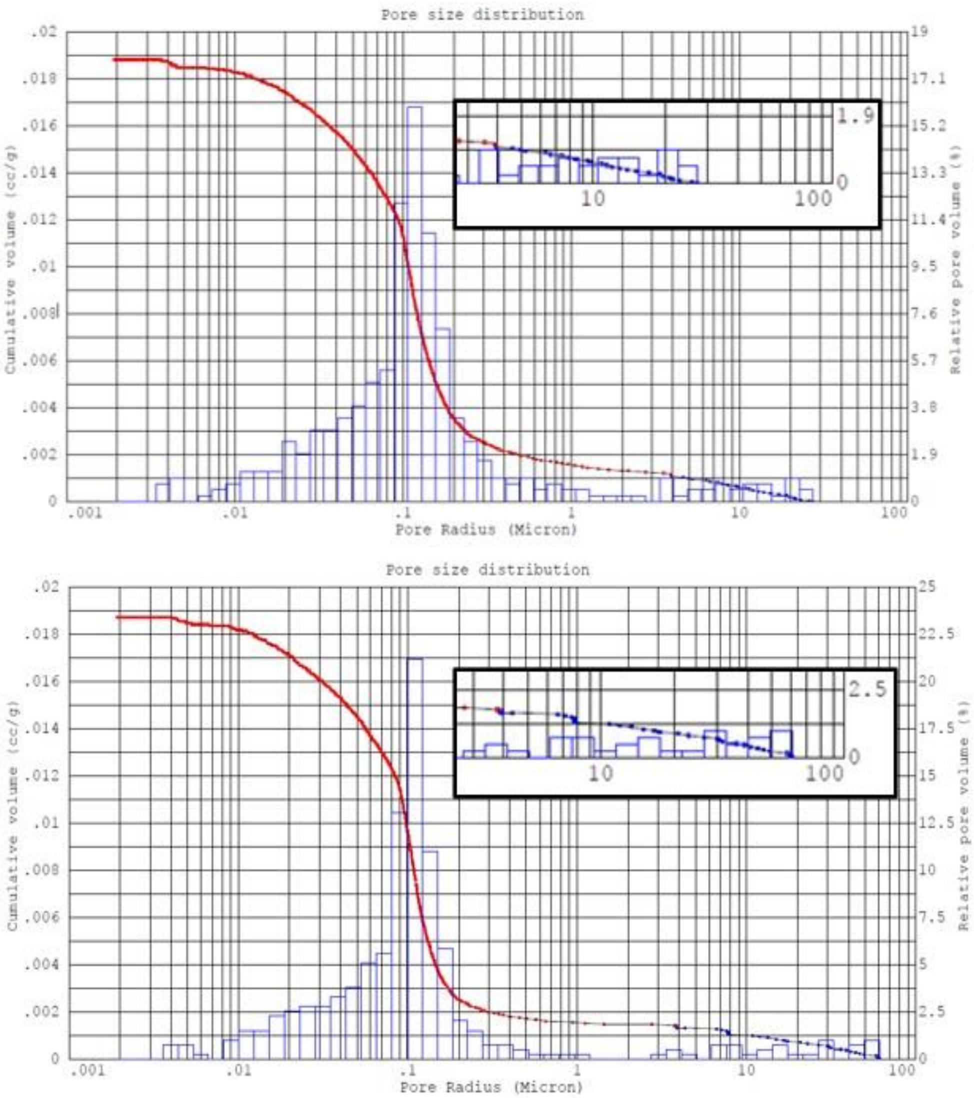

Figure 10
Microcrack appearance on pore-throat distribution curves for Bék-5/3/1 and 5/3/2 samples

It is worth taking a closer look at the phenomenon. The model sample built from Bék-5/3/2 specimen data shows the weighted gas flow rates for pipe diameters above 10 microns in *Figure 11*. The results of the simulated measurement are summarized in *Table 2.*

Table 2
Simulation results
regarding flow rate values above 10 microns
in Bék-5/3/2 sample

Radius (μm)	**Flow rate (cm^3/s)**
49.417	5.865E-08
40.174	8.068E-08
32.660	4.925E-08
26.551	5.799E-09
21.585	5.461E-09
17.548	2.598E-09
14.266	1.249E-09
11.598	6.069E-10

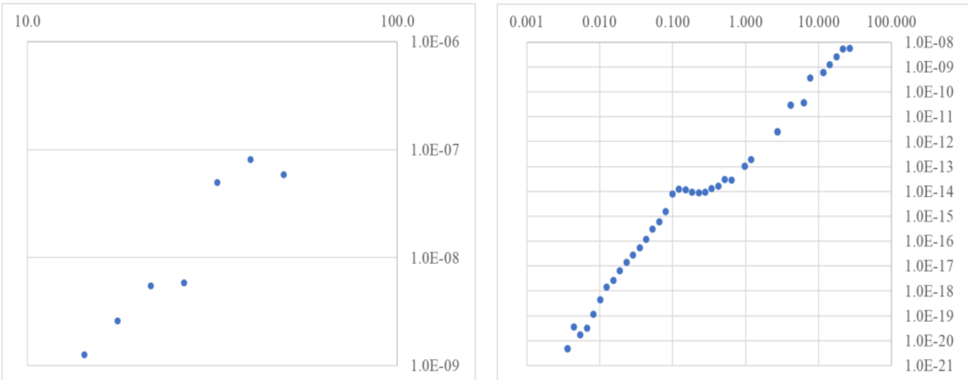

Figure 11
Simulation results regarding flow rate values
above the 10-micron region in Bék-5/3/2

On the left part of *Figure 11*, the 3 seemingly insignificant points which show the values of the gas flow passing through the largest diameter pipes show a significant difference over the whole sample. It can be observed that the 3 points indicate one order of magnitude larger values compared to the gas flow rates belonging to the next smaller diameter of the model sample; hence, the inclusion of these non-characteristic value points increases the total gas flow by an order of magnitude. All calculated flow rates regarding every pipe diameter are shown in the right part of *Figure 11*. It should be noted that with the decreasing pipe diameter, the gas flow rate is excessively reduced. In the most typical pore-throat sizes of the rock matrix, the gas flow rates are 6 orders of magnitude lower compared to the diameter range of 10 to 100 microns. We performed the elimination of microcracks and the necessary calculations for all six model samples built from the Bék-5/3 core well data series. The weighted flow rates are shown in *Figure 12*, while the results for total gas flow can be found in *Table 3*. Finally, the characteristic parameters are illustrated together in *Figure 13*.

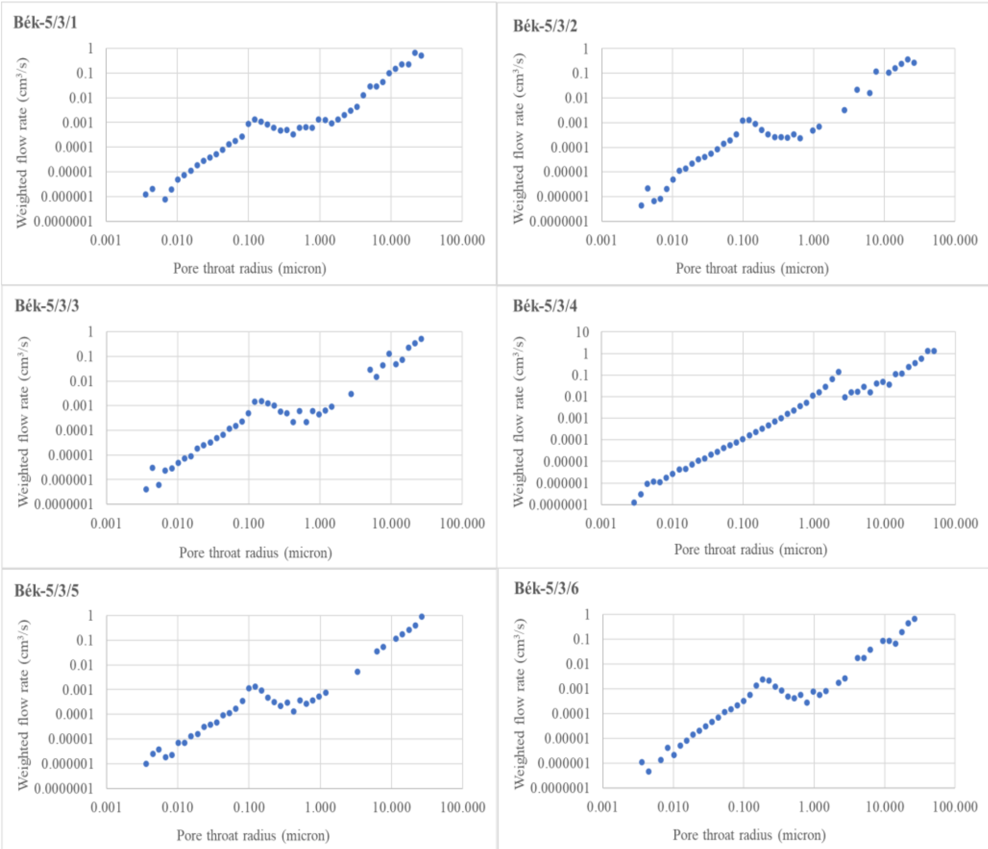

Figure 12

Weighted flow rate values as a function of pore radius under the 1-micron region

Table 3

Calculated total gas flow rates in the model samples

Plug	Bék5/3/1	Bék5/3/2	Bék5/3/3	Bék5/3/4	Bék5/3/5	Bék5/3/6
Total gas flow rate (cm^3/s)	0.02656	0.01615	0.01978	0.08599	0.03072	0.02427

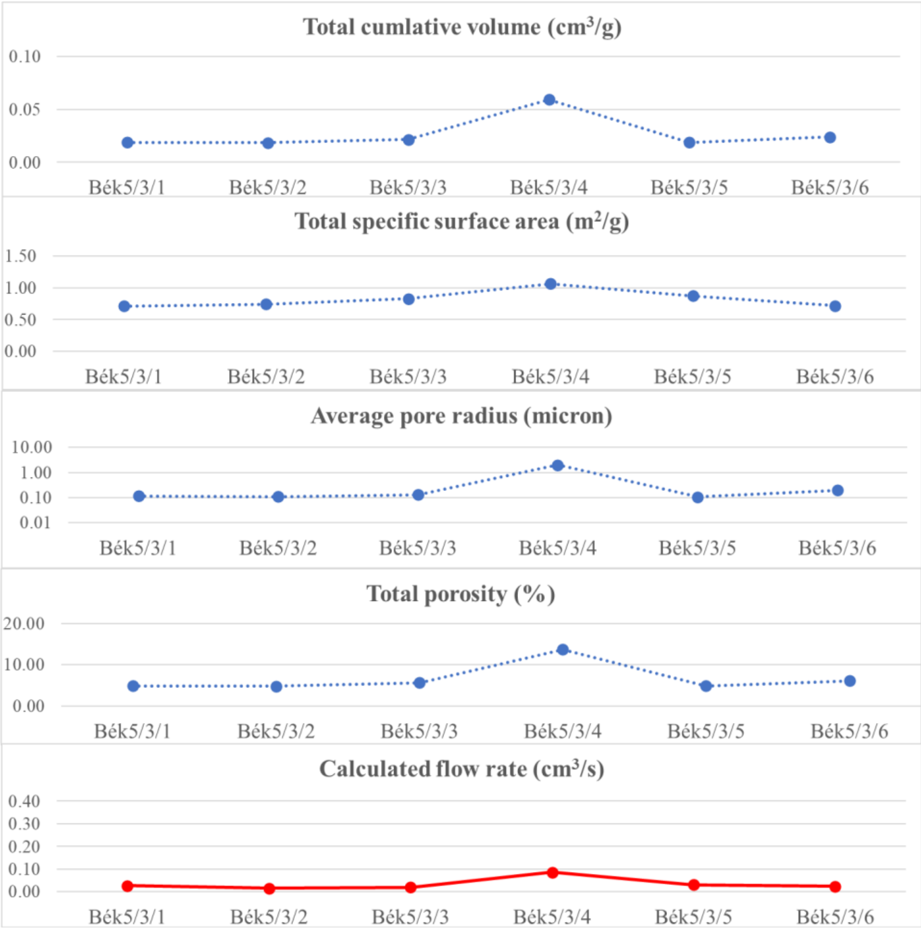

Figure 13

All characteristic parameters along with the calculated gas flow rates in Bék-5/3 drilling core

4. Conclusion

The results published in the article prove that petrophysical measurement data of the rocks of unconventional hydrocarbon reservoirs should be treated with caution, especially regarding the measured values of the permeability. Correction of the measurement results may be necessary based on the determination of the flow ranges in the pores. Outside the Darcy flow range a Knudsen number-based correction should be used. In case of damage and the presence of microcracks, permeability values measured by the proper instruments often cannot be descriptive. For their correction or replacement, a procedure using model samples is under development which was applied to a small number of specimens with high similarity to each other and in this case, could successfully determine flow rate values.

ACKNOWLEDGEMENT

The research was carried out in the framework of the GINOP-2.3.2-15-2016- 00010 *Development of enhanced engineering methods with the aim at utilization of subterranean energy resources*" project of the Research Institute of Applied Earth Sciences of the University of Miskolc in the framework of the Széchenyi 2020 Plan, funded by the European Union, co-financed by the European Structural and Investment Funds.'

REFERENCES

[1] Zobak, M. D., Kohli, A. H. (2019). *Unconventional Reservoir Geomechanics: Shale Gas, Tight Oil, and Induced Seismicity*. Cambridge: Cambridge University Press, DOI: 10.1017/9781316091869.

[2] Javadpour, F. (2009). Nanopores and Apparent Permeability of Gas Flow in Mudrocks (Shales and Siltstone). *Journal of Canadian Petroleum Technology*, 48 (08), pp. 16-21. DOI: 10.2118/09-08-16-DA.

[3] Ziarani, A. S., Aguilera, R. (2012). Knudsen's Permeability Correction for Tight Porous Media. *Transport in Porous Media*, 91, pp. 239–260. DOI: 10.1007/s11242-011-9842-6.

[4] Remeczki, F. (2020). Matematikai módszer a márga minták kialakítása során keletkező mikrorepedések hatásának eliminálására. *Bányászati Kohászati Lapok*, 2–3., pp. 27–31.