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Evaluation of Carbonate Rock Permeability, with the Use of X-ray Computed Microtomography

Introduction

Reservoir Rocks Characterization

Due to the depletion of the world's hydrocarbon deposits, better ways of reservoir rock characterization are required. Better borehole terrain recognition provides more efficient use of earth resources and it saves money as well. The most important parameters of reservoir rocks are porosity and permeability. They are measured in laboratory tests (density measurements and gas or fluid permeability test). On the basis of laboratory tests, the parameters of the whole borehole are extrapolated, and other measurements (in-situ borehole testing) are calibrated [3, 9].

X-ray Computed Microtomography

X-ray computed microtomography (CMT) has been applied to characterize rock since the 1990`s [6]. The ability to examine the real shape of macropores provided new opportunities for laboratory tests on reservoir rock. Modern CMT scanners allow to obtain three-dimensional images of rocks' internal structures, with the resolutions down to 50 nm in each direction [4]; however, such scans are not useful for oil industry due to small sample dimensions (width: about 60 μm). According to the tomography principles, the resolution is determined by the X-ray-source to X-ray-detector distance, sample width to detector width ratios and X-ray spot size (proportional to X-ray tube power). However, the porosity estimated with the use of computed microtomography data is usually lower than that calculated on the basis of density (absorption) measurements, and the results of CMT rock porosity examinations are consistent with nuclear magnetic resonance evaluation of effective porosity [18]. The X-ray computed microtomography data had been used before to estimate the relative permeability of rocks [7, 11]. Other works [1, 8] showed the possibility of calculating the permeability of simple, periodical systems which were calculated on the basis of CMT images; however, no results of rock permeability calculations have been published so far.

Navier-Stokes Equations

The Navier-Stokes equations [8]:

$$p\frac{du}{dt}+(pu\cdot\nabla)u=-\nabla p+\nabla\cdot\left\{\eta\left[\nabla u+(\nabla u)^T\right]\right\}+F \quad (1)$$

$$\Delta u=0 \quad (2)$$

are the fundamental fluid motion equations. In equations (1) and (2), p is pressure, u is fluid velocity, t is time, η is the fluid dynamic viscosity and F is the external force field (vector quantities are marked in bold). However, these equations for three-dimensional problems are one of the seven most important open problems in mathematics, and they can be implemented and solved with the use of finite element method (FEM). For a stationary flow of a non-compressive fluid, equation (1) may be simplified to the following form:

$$(pu\cdot\nabla)u=-\nabla p+\nabla\cdot\left\{\eta\left[\nabla u+(\nabla u)^T\right]\right\} \quad (3)$$

The existence and smoothness of Navier-Stokes equations in three dimensions are not proven, but there were attempts at solving them in a FEM model, based on CMT images [8, 17]. Also, the permeability of a simple system (column packed with glass beads) was calculated on the basis of the Navier-Stokes equation solution [8], with the use of the following equation:

$$k_{N-S} = \frac{\frac{\phi}{A} \cdot L_z \cdot \int_A w dA}{\frac{\Delta p}{\eta}} \qquad (4)$$

where $k_{N\text{-}S}$ is permeability (in milidarcy), ϕ is the sample's image porosity, A is the area of fluid outflow, η is the fluid's dynamic viscosity, w is the velocity z-component and Δp is the pressure difference on the opposite sides of the sample in the z direction. The results were consistent with permeability measurements.

Objectives

This paper has two main objectives. Firstly, we want to show a methodology to evaluate the permeability of carbonate rocks, with the use of X-ray computed microtomography data. Secondly, we want to evaluate the combined CMT/FEM methods as a way to calculate rock permeability.

Experimental

Samples

Three carbonate rock samples originating from boreholes in Poland were examined. Sample characteristics (measured with the use of density measurements and the nitrogen permeability test) is given in Table 1. For the purpose of CMT measurements, samples were cut to the form of a core, with the diameter of 10 mm. As we will describe in 2.4 below, during the image processing, our images were cropped to cuboids, with the dimensions 5.8 × 5.8 × 2.32 mm^3.

Table 1. Examined rock properties; porosity (ϕ_{exp}) was calculated, with the use of helium density measurements, and permeability (K_{exp}) was estimated on the basis of gas permeability test, with the use of nitrogen as carrier gas

Sample	ϕ_{exp} [%]	K_{exp} [mD]
1	1.29	0.09
2	14.81	37.34
3	4.90	0.22

Micro-CT Measurements

Measurements were made with the use of a Benchtop (Nikon) CT160Xi microtomograph. An X-ray tube, with a tungsten anode and spot size down to 3 µm, were applied. X-ray intensity was measured on a Varian PaxScan 2520V flat panel detector, with the pixel area of 127 × 127 µm^2 (dimensions: 1916 × 1536 pixels). During measurements, samples were placed on the holder. For rock imaging, the X-ray tube voltage was 110 kV and the current was 50 µA (power: 5.5 W). About 3,000 projections were made during the 360° sample rotation. Our experimental setup is shown in Figure 1.

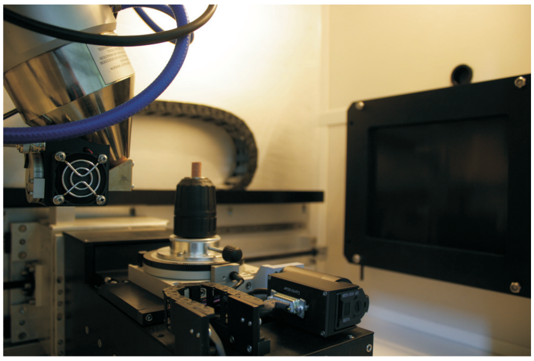


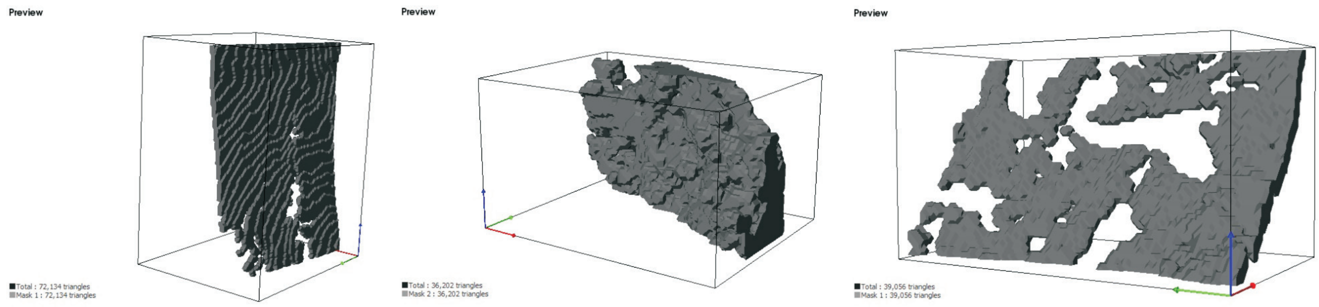
Fig. 1. Experimental X-ray computed microtomography setup; from left to right: X-ray gun, core holder, flat panel detector

Image Processing

The internal structure of each core was reconstructed with the use of the X-Tek CT-Pro [15] software. Reconstructed RAW data were imported into the Avizo 6.1 [14] and cropped to a cuboid, with the dimensions of 1000 × 1000 × 400 voxels. This volume was binarized, with the use of phase-mean thresholding [5]. The number of phases on a grey-scale image was estimated visually. 10 voxels from each phase were randomly taken and phases' mean grey values were calculated. Threshold values were calculated as the mean of two phases' mean grey value.

Our main assumption of the model preparation was that fluid might flow only through the pores which were noticeable, with the use of used CMT equipment, and the rock matrix was impermeable.

Pores were extracted in the Simpleware ScanIP 4.0 [12]. With the use of the FloodFill tool, the pores with outlets on both sides of the sample in the z direction were selected. Then, the image was downsampled (the factor was determined by aperture geometry), with the application of the nearest neighbouring algorithm [10, 16]. A dilatation morphological filter was applied to avoid pore rupture during the resampling process. The dilatation process also led to a decreased number of mesh elements and reduction of computation time. The STL surface of extracted and downsampled pores was generated. Pore meshes are shown in Figure 2.



a) b) c)

Fig. 2. Extracted, downsampled and dilated pore model used to create FEM meshes: (a) Sample 1 (downsampling factor 5), (b) Sample 2 (downsampling factor 3), (c) Sample 3 (downsampling factor 10)

Table 2 shows geometrical model parameters necessary to calculate permeability according to equation 4.

Table 2. Geometrical parameters of CMT images used for creating FEM meshes

Sample	$L/10^{-3}$m	ϕ [%]	$A/10^{-7}$m^2
1	4.032	1.1	3.2
2	0.792	10.3	1.3
3	3.312	1.9	7.8

FEM Calculations

Each STL surface was imported into the COMSOL Multiphysics 3.5 [2] software. The constants: temperature (T = 298 K) and pressure (p_0 = 101325 Pa) were defined. Fluid inlets and outlets were defined on the samples' opposite sides, along the z direction. Inlets were defined by pressure ($1.05p_0$), while outlets were open boundaries.

Nitrogen parameters (ρ = 1.20 kg·m^{-3}, η = 1.76 · 10^{-5} P for chosen T and p_0) were taken from the COMSOL Material Library. Calculations were run with the use of the Paradiso (DIRECT) solver. The use of complex functions with real input was allowed. Subdomain calculations were stabilized by the use of GLS, crosswind diffusion and isotropic diffusion. Calculations were conducted on a Dell workstation equipped with the Intel Xeon E5430 2.66 GHz and 32 GB of RAM memory. COMSOL was running on the Windows Vista 64-bit operating system.

Results and Discussion

The results of our simulations are shown in Figure 3.

The number of degrees of freedom (DOF) and the calculation time for each model are shown in Table 3.

Table 3. Numbers of the degrees of freedom (DOF) and time necessary to perform FEM calculations for each sample

Sample	DOFs	t/s
1	918 600	630
2	1 080 300	1 600
3	1 865 000	1 830

The average calculation time was about 23 minutes per calculation, which was a bit longer than the time needed to perform a gas permeability test (15 minutes approximately). It is worth mentioning that the calculation time will be decreasing with the development of modern computer hardware, so, in years to come, the time of FEM calculations will be shorter than the gas permeability experiment.

The results of permeability calculations are shown in Table 4. Also, the absolute error was calculated as follows:

$$\Delta K = \left| K_{exp} - k_{N-S} \right| \qquad (5)$$

and the relative errors were calculated with the use of the following equation:

$$\Delta k = \frac{\left| K_{\exp} - k_{N-S} \right|}{K_{\exp}} \cdot 100\% \qquad (6)$$

are shown in Table 4. It was assumed for the error calculation purposes that permeability measured experimentally (Table 1) was the real value of the sample permeability.

As it is shown in Table 4, the calculated permeability is close to the permeability measured with the use of a classical well logging method. That demonstrates that the methodology applied in our permeability calculations was correct in the case of carbonate rocks with apertures. Also, the results showed the applicability of equation (4) for real structures. The difference between experimental and

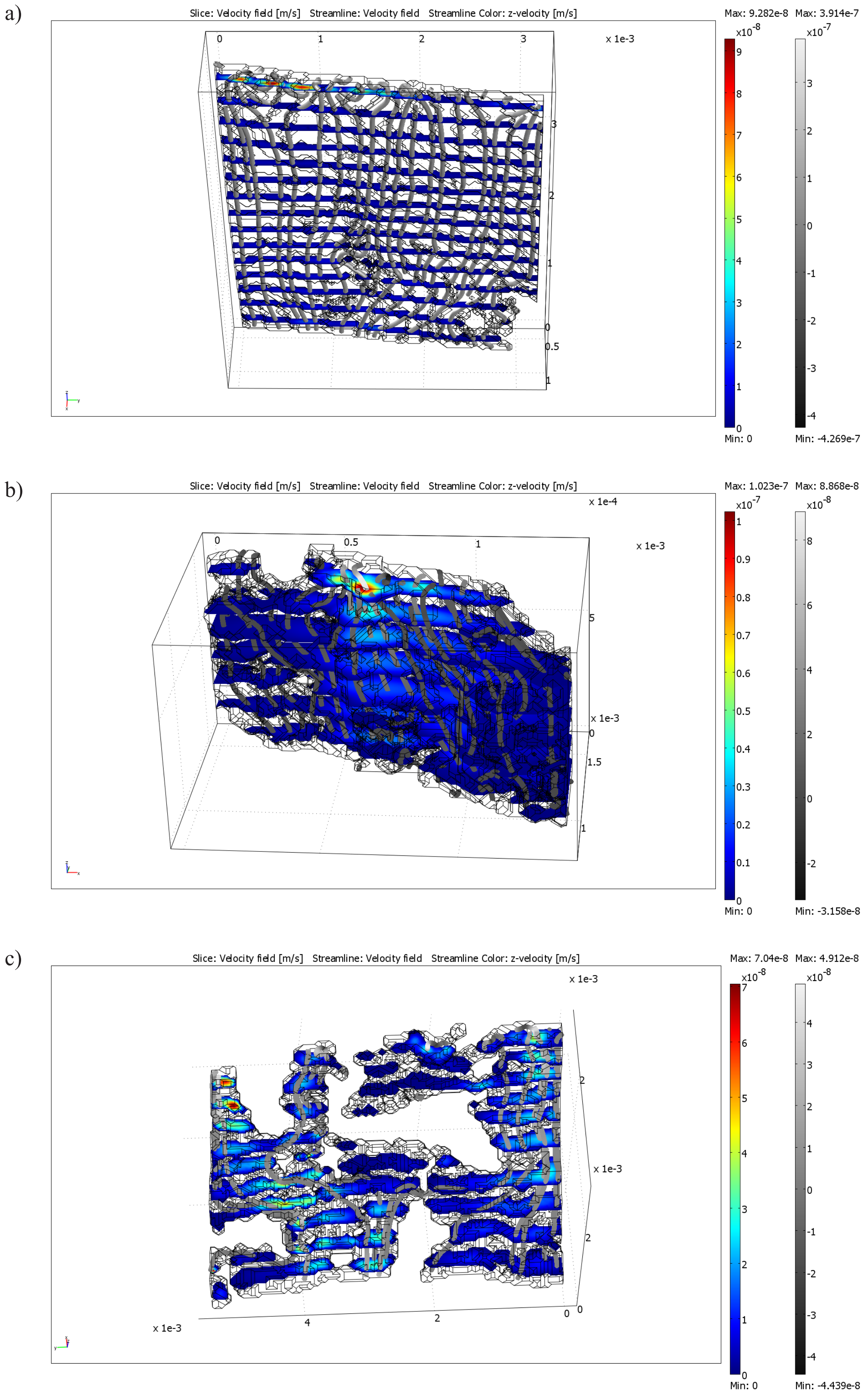


Fig. 3. Simulation results: (a) Sample 1, (b) Sample 2, (c) Sample 3; slice colours show velocity field values, streamlines: velocity field directions, and streamline colours: *z*-velocity component

Table 4. Calculations of simulated permeability ($k_{N\text{-}S}$) of carbonate rocks

Sample	Δp [10^{-7} Pa]	$\int_A wdA/10^{-15} m^3 \cdot s^{-1}$	$k_{N\text{-}S}$ [mD]	ΔK [mD]	Δk [%]
1	30.9	2.2	0.07	0.02	22.2
2	6.6	2.1	36.43	0.94	2.5
3	43.6	5.7	0.11	0.11	50.0

calculated permeability values was no greater than 1 mD. However, the relative errors in cases of Samples 1 and 3 were big, although the absolute differences were acceptable for our well logging requirements. The high relative error in case of those samples was the result of low rock permeability. Those errors would not disrupt the evaluation of the rock reservoir parameters according to the standard classification [13].

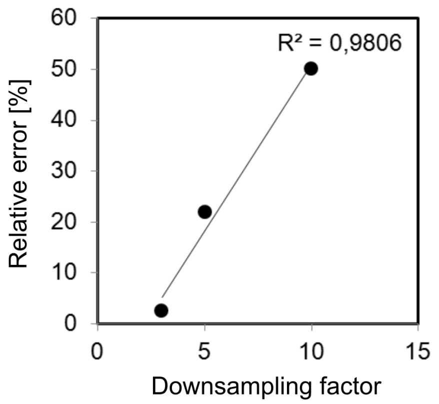


Fig. 4. Correlation between the relative error of simulation (equation 6) and the model downsampling factor

As it was shown in Fig. 4, the relative error for the examined samples was in straight correlation with image downsampling factors. However, the R^2 factor was close to 1. It was calculated on the basis of 3 points, so it may be approved only as a general trend. This means that the more simplified pore space geometry, the higher the difference between the measured and the simulated permeability values. The downsampling factor was chosen during the described research by decreasing it until the meshed STL surface had about 300.000 mesh elements. Calculation of a more complicated model was impossible to run due to unavailability of suitable computer hardware and software. Probably, simulation results may be improved with the use of more efficient hardware and less downsampled CMT images. Also, better results may be obtained if the model is generated on the basis of smaller CMT images. The selection of the smallest representative image of carbonate rock will be the aim of further research by the authors.

The obtained resolution $(5.8\ \mu m)^3$ was an optimum resolution for a core, with diameter of 10 mm in view of the CMT equipment applied. The cores with higher diameters may also be measured, but a worse resolution will be obtained, and it may result in higher distortions of pore shapes and no observation of thin connections between them will be possible.

It is considered that oil flow is allowed in pores with the diameter higher than 3 µm, but this paper has demonstrated that the resolution of about 6 µm is good enough for permeability calculations. That means that most of the fluid flows through the pores connected by channels whose volume is higher than 195 μm^3. However, the resolution and assumption mentioned in 2.3 that the rock between the pores is impermeable may also increase the error of permeability estimation.

The consistence of permeability values and the correlation between downsampling factors and permeability relative errors show that permeability is determined mostly by the pore space geometry (Euler's number, tortuosity and the shape factor). The relationship between the pore network topology and permeability will also be part of the authors' further research.

As it was mentioned before, high relative error values do not exclude the combined X-ray computed microtomography and finite element method simulations from their application in reservoir rock examinations in the oil industry. The changes in permeability, observed with the use of the classical permeability test, are also observed in simulation results. Besides, rock identified as good or poor reservoir rock on the basis of the gas permeability test will be identified as well on the basis of CMT-FEM calculations.

Summary

The results of finite element method nitrogen flow simulation for three carbonate rock samples have been presented. Meshes were prepared on the basis of X-ray computed microtomography images of rocks.

It was assumed that fluid might flow only in visible pore systems, and the rock matrix was impermeable. The CMT image was binarized and downsampled. Then, a dilatation filter was applied and the pores which provided the connection between the image borders in the *z* direction were extracted. The STL surface was exported to FEM software and meshed. The consistence of our experimental measurements and of simulation results demonstrated that the methodology applied was appropriate to prepare our CMT-based FEM model.

The results have shown that the CMT-FEM combined method may be used to petrophysical rock examination for the purpose of borehole evaluation in oil industry. The CMT image resolution obtained (5.8 μm in each direction) was sufficient to estimate rock permeability. Our results demonstrated that the fluid flow occurred mainly in the pores connected by channels whose volume was higher than 195 μm^3.

The discrepancy between simulation and measurement results was caused by geometry simplification during image processing. Correlation between the relative error of permeability calculation and the image downsampling factor suggested that rock permeability was a function of pore space geometry, and that is what will be further investigated in the authors' future research.

Acknowledgements

This paper includes results obtained during our statutory research project no. DK-4100-26/10, funded by Ministry of Science and Higher Education of the Republic of Poland.

Artykuł nadesłano do Redakcji 19.01.2011 r. Przyjęto do druku 1.02.2011 r.

Recenzent: prof. dr hab. inż. Andrzej Kostecki

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