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DEVELOPMENT OF IMPROVED METHOD FOR EVALUATION OF RESERVOIR PROPERTIES OF FORMATION

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 assessing reservoir properties has a significant number of sources of uncertainty. In this article, to compensate for the shortcomings of the existing method of reservoir characterization, an algorithm of actions is proposed with an increase in the accuracy and representativeness of its results.

The workflow of the pre-alpha version of the software for the existing pore space representation algorithm is presented. In this work, the step-by-step actions necessary to create an application that can reproduce the pore space and mass transfer processes in it by reading the data of the magnetic resonance imaging (MRI) of the rock were analytically determined. In particular, the use of ready-made open code is proposed, which displays the rock according to the pictures and also reproduces the fluid flow processes in the rock reservoir. Still, there is no adapted framework for the ordinary user.

The use of such an application, proposed by the authors, will lead to a much lower degree of the reservoir properties uncertainty, will help to more reliably reflect the reservoir properties of the reservoir rock, and provide a more reliable impression of the reservoir operation at the design stage of its development.

The proposed software, based on already existing developments in open access on the GitHub platform, will help the user to fully use the existing tools for building a three-dimensional model of a porous sample based on the data of MRI images of the rock.

After finalizing the user interface with the help of the user interface design and front-end development, the engineering staff will be able to conduct research on the rock at a macroscopic level.

Keywords: *fluid transfer, porous media, pre-alfa version, reservoir rock, uncertainty degree.*

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1. Introduction

For engineers, who evaluate reservoir properties, the task of creating a representation of the pore structure of the rock is urgent. A wide range of laboratory methods are used to determine the porosity and permeability of a rock sample [1–3]. The disadvantage of laboratory methods is that their results are based exclusively on the basis of surface interaction with the test sample, and not volume. In the Ukrainian context, morally outdated methods and equipment are added to the above. These methods have a number of objective disadvantages, listed in [1], among which the focus of the presented study is the lack of a digital 3D model of the test sample.

Without such a model important phenomena like healed cracks or isolated pores might be left out of an engineer's attention which significantly compromises the reliability of reservoir evaluation data and hydrocarbon field development plans that follow.

The creation of the mentioned above 3D model requires specialized software that would tackle this problem and give certain rock features such as porosity distribution, cracks occurrence, and permeability as output data in a low-cost fashion. Formation evaluation specialists need a customized software product by tailoring some existing solutions. In addition to that, the development cost must be low.

Therefore, it is an urgent task to create a methodology for the study of reservoir rock samples, which would be based on the volumetric representation of the porous structure of the sample as opposed to the surface interaction of the sample with laboratory equipment.

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 experimentally determining the porous structure of a rock sample.

2. Research methodology

The initial material for the study is a core sample, taken from the field. The traditional methods imply its saturation and drying cycles followed by estimating the pore space volume using the amount of liquid absorbed as a key factor [1]. In the present study, it is necessary

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a 3D visualization of the sample that would reflect all the fractures within it. The mentioned model will enable the calculation of pore volume, pore connectivity, and permeability. It also recreates the pore geometry of the sample that directly impacts the permeability. Having estimated the latter one will be able to simulate the oil displacement process, water flooding, and hydro-carbon recovery.

Pore space reconstruction does overcome some of the limitations of direct imaging, but even then it does not address how to quantitatively characterize filtration and mass transfer in these models. This requires some degree of simplification of the void geometry and connectivity below after some important and basic definitions are introduced.

X-rays are used to scan the pore space to create three-dimensional images with micron resolution. The principles and methodology used to construct the image are similar to those used in computed tomography for medical examinations [2].

Such images are to be digitized and used in the sample's model reconstruction. Studying a rock sample at the micro level will help to eliminate certain uncertain-ties that cannot be ascertained without scanning the sample with X-ray radiation, for example, uncertainty due to rock fissures. Cracks are usually filled with a different composition of rocks, which is different from the main studied sample. The porosity of the healed crack is not representative of the entire sample and introduces significant uncertainty if it is not visible but present in the sample. X-ray radiation reveals such anomalies and will help to take this into account when determining collector properties [1].

For further processing, two more software are to be used Lattice Boltzmann method adapted for porous media (LBPM) and a program for three-dimensional visualization (Vislt). LBPM is a modification of LBM (Lattice Boltzmann Method). LBM is a well-known CFD modeling tool that provides highly reliable results. CFD open source software based on the numerical model of the Lattice Boltzmann method LBM. CFD is mainly applied and used on a large scale and mega-scale, simulating fluid flow in a chamber, simulating airflow taking into account air conditions.

If to consider porous media, from the point of view of geometry, they are absolutely different from a normal CFD simulation because the user has no control over the geometry, the geometry is not defined by the user, unlike a porous me-dia. The behavior of the liquid flow in the porous medium will be the result of modeling how it flows inside the porous medium through the pore channels. The relative performance of different porous media in the aforementioned applications strongly depends on the internal pore structure of each material [1]. From this, it is possible to establish a direct relationship between filtration behavior and morphological indicators of various porous media. The main task of the al-ready existing calculation algorithm which is on the GitHub resource is to link the pore structure with hydraulic functions, such as permeability, capillary pres-sure and diffusivity, which are necessary for engineering applications. This software code and algorithm is the most reliable Western technique for determining pore size and geometry from scanned magnetic resonance images (MRI) of reservoir rocks. It helps to establish at the macro-scale level connectivity, porosity, permeability to other reservoir properties of the rock, and also helps to establish the influence of the geometry and characteristics of the rock on mass transfer processes [2].

LBPM is an open-source software platform designed for modeling flow pro-cesses based on digital rock physics [4]. The publisher is Open Porous Media Initiative. The main difference between LBPM compared to LBM:

– the computational geometry/mesh must be obtained by transforming/remapping the micro-CT image of the core sample into a cubic lattice;
– phases are distinguished by whole numbers, for example, 1: liquid, 0: solid for single-phase and 1: liquid 1; 2: liquid 2; 0: solid for biphasic and so on.

The program code of LBPM is Open Source, that is, open for use and for modifications and additions. If desired, anyone can join the development of the project. License terms. Commercial use, modification, distribution, creating a patent based on the code, and private use is allowed. But the company is not responsible for the results and cannot be sued in case of damages.

Next, visualization and image analysis are carried out [5]. X-ray scanning is useful because there is a clear contrast between rock, which absorbs X-rays strongly, and fluids, which are more transparent to X-rays. This makes it easy to distinguish between solid rock and pore space, and, thanks to a careful design of the experiment, between liquid phases. X-rays show both the porous media them-selves and the chemical, biological, and flow processes occurring in them [6].

LBPM presents a code specially developed on the basis of open source, which performs the procedure of transformation of a series of pictures of sections of rock into a digital non-visualized matrix where the entire space of the sample is divided into free space and the body of the rock.

In theory, there are two combined approaches that calculate the geometry of the pore medium. The essence of the first method is to represent the porous medium in voxels and iteratively reduce the voxels until a voxel is formed in the porous medium (the centers of these voxels will be equidistant from the surfaces of the rock grains) and connected connections are formed from these porous voxels. The medial axis is the axis of the pore space, a series of points distant from the solid surface, successively repeating the same algorithm of actions until a certain result is achieved (the size of the voxels was reduced to reach the desired size).

The second method consists in taking the pore points to enlarge to the inter-section with the solid surface. All balls found in the middle of the larger ball are ignored. Other cascading balls that do not completely overlap are assigned to the same family and so on until a small ball is found that will belong to two families at the same time. This small ball is the throat between the pores.

The combined method uses image analysis. Just as in the previous one, there are the largest distances of the radii of pores. Then the voxels located in these specific pores are identified. This space is recognized cf. then let's uses the water-shed concept: water will flow into those pore areas with the largest sphere radii through the smaller voxels that are also assigned to that pore. The throat with the smallest radius is the watershed, it is connected to 2 different pores [7].

Returning to the LBPM software, the images are further segmented and decomposed. Let's work with microscopic data, the result of X-ray scanning. It is necessary to segment it into separate phases in order to distinguish the solid, and liquid phase, different types of deposits, and most importantly, to distinguish the boundary between voids and a solid body. Then there is a decomposition for a certain number of graphics processors or central processors that are available.

For one phase, a central processor module is available that calculates absolute permeability from relative permeability.

Color simulation is similar to LBM. It is necessary to apply morphological modifications and also add certain parameters of the sample to prepare it for multiphase modeling. Since simulating a multiphase flow, it is necessary to specify not one, but several relaxation coefficients.

SILO output data or calculation results are visualized simply and quickly without time delays in the Vislt software. The visualization might be used by an engineer to understand and quantify the sample's porous microstructure and verify the results obtained by the traditional method.

Further, at this stage, it is necessary to determine the representative elementary volume of *REV*. This is the volume of the rock sample that is representative of a certain volume of the product. This calculation is necessary for the correct de-termination of the reservoir characteristics of the rock (porosity, permeability, connectivity etc.) that correspond to the considered volume [2]. That is, there is a certain volume *A* of the rock sample. There is the task of extracting from it the necessary smallest volume *B*, which is identical, equal in terms of collector properties at any point of the same volume *B* for a rock sample of volume *A* with an error of 0.5 % (Fig. 1). It should be noted that it is impossible to determine such a volume *B* of such a studied sample of volume *A* that satisfies all the porous structures of the rock at the same time. Each reservoir rock has a unique size and shape of grains, conditions of its random occurrence, as well as deformation in formation conditions, which are significant factors of influence on *REV*. Therefore, the *REV* is calculated individually for each case and depends on the chosen feature that is being investigated, as well as on the size of the volume of the space being investigated [2].

For the statistical descriptions of the pore space mentioned above, the size REV can be estimated from the correlation length of the local porosity or associated path length. In rock samples, a volume covering a few grains is generally sufficient to determine porosity, while a larger volume is required for saturation, as this is controlled by the dynamics of the process by which fluids are displaced. For flow properties, especially when multiple phases are present, the *REV* is even greater because it now depends on the relationship between the pore space and the fluids within it [8]. As an example, Fig. 1 illustrates the average porosity calculated by the *REV* formula.

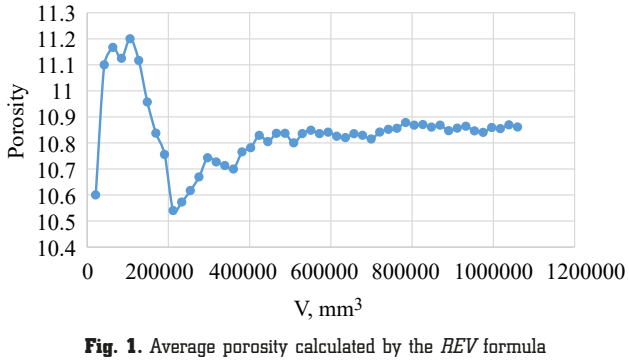

Fig. 1. Average porosity calculated by the *REV* formula

Such iterations with *REV* can be carried out at any stage of scaling the considered volume. This is one of the most important functions of *REV*, because it is possible to extrapolate the results of the collector properties of the studied rock samples from the micro level to the general scale of the formation, which can reach kilometers, at the expense of *REV*.

At the moment, the question of scaling is an urgent question of today and is not sufficiently studied to be able to reliably transfer the results of the microscale to the macrolevel. Since there are certain limitations that have a significant im-pact when considering the scope. These restrictions concern the forces acting in the pore space during the mass transfer process. *Lamina REV*, i. e., on a microscale, the forces of capillary tension mainly act, on *Lithofacies REV*, on a medium scale, the viscosity of liquids is of the greatest importance, as the scale of *Sequence REV* increases, the force of gravity begins to dominate [9].

Due to the influence of different forces at each scaling stage, the coefficients obtained at the micro-level are not final and require the addition of other representative scaling volumes. The developers of the program themselves will indicate that they are not responsible for the results obtained.

3. Research results and discussion

The method proposed in this study has been tested by the example of Bentheimer Sandstone assumed to be a sample of a hydrocarbon-bearing formation [10]. Its X-ray images are available under open access conditions (Fig. 2).

To run this simulation, it is necessary to download three files:

1) input.db – information on predicted domain structure and domain decomposition provided by LBPM;

2) mask.raw.morphdrain.raw – digital image of rock saved as raw binary;

3) run.sh – script that helps to set common command line arguments and is to be placed in the data compare directory [11].

In the input.db tab, let's set the necessary parameters: mesh size, length of each voxel, error size, the relaxation time of each fluid, density of each fluid, velocity pressure storage parameters for rendering, etc. (Fig. 3). The mask.raw.morphdrain.raw file contains the reservoir rock input, i. e. the X-ray images of the rock. The run.sh file plays the role of architecture for the invidia graphics card.

The software generated a file in a separate vis10000 folder and an LBM.vislt file. Let's put the raw data into the Vislt program and get a 3D prototype of the studied rock sample [12]. This is our final data that can be further used by an engineer to get insight into the internal pore structure of the rock sample under investigation and find clues invisible to the naked eye (Fig. 4).

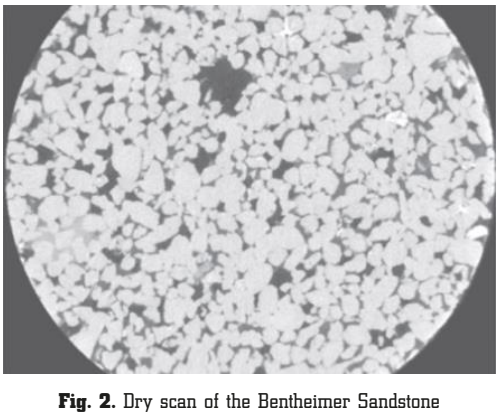

Fig. 2. Dry scan of the Bentheimer Sandstone

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```
Domain {
   Filename = "mask_water_flooded_water_and_oil.raw.morphdrain.raw"
   nproc = 1, 1, 1     // process grid
   n = 300, 297, 500   // sub-domain size
   N = 300, 297, 500  // size of original image
   voxel_length = 7.0  // voxel length (in microns)
   ReadValues = -1, 0, 1, 2  // labels within the original image
   WriteValues = -1, 0, 1, 2 // associated labels to be used by LBPM
   BC = 4                // boundary condition type (0 for flux)
   Sw = 0.35
}
MRT {
   tau = 1.0
   F = 0.0, 0.0, 1.0e-5
   timestepMax = 20000
   tolerance = 0.01
}
Color {
    tauA = 0.7;            // relaxation time for fluid A (labeled as "1")
    tauB = 0.7;            // relaxation time for fluid B (labeled as "2")
    rhoA   = 1.0;          // density for fluid A (in lattice units)
    rhoB   = 1.0;          // density for fluid B (in lattice units)
    alpha = 1e-3;          // controls the surface tension
    beta  = 0.95;          // controls the interface width
    F = 0, 0, 0            // controls the external force
    Restart = false        // initialize simulation from restart file?
    timestepMax = 1000    // maximum number of timesteps to perform before exit
    ComponentLabels = 0, -1     // number of immobile component labels in the input image
    ComponentAffinity = -1.0, -0.9  // wetting condition for each immobile component
    flux = -10.0              // volumetric flux at the z-inlet in voxels per timestep
}
Analysis {
    analysis_interval = 1000         // Frequency to perform analysis
    visualization_interval = 1000  // Frequency to write visualization data
    restart_interval = 1000000       // Frequency to write restart data
    restart_file = "Restart"         // Filename to use for restart file (will append rank)
    N_threads     = 4                // Number of threads to use for analysis
    load_balance = "independent"     // Load balance method to use: "none", "default", "independent"
}
Visualization {
    write_silo = true     // write SILO databases with assigned variables
    save_8bit_raw = true  // write labeled 8-bit binary files with phase assignments
    save_phase_field = true  // save phase field within SILO database
    save_pressure = false    // save pressure field within SILO database
    save_velocity = false    // save velocity field within SILO database
}
```

Fig. 3. The code fragment

In this way, by setting the appropriate parameters of the fluid, it is possible to simulate the process of the flow of several phases in the pore space.

The described methodology can be applied to any rock sample to obtain a volumetric representation of its structure. The obtained data provide an opportunity to verify the results of laboratory studies according to existing methods and to exclude the sources of uncertainty specified in [1].

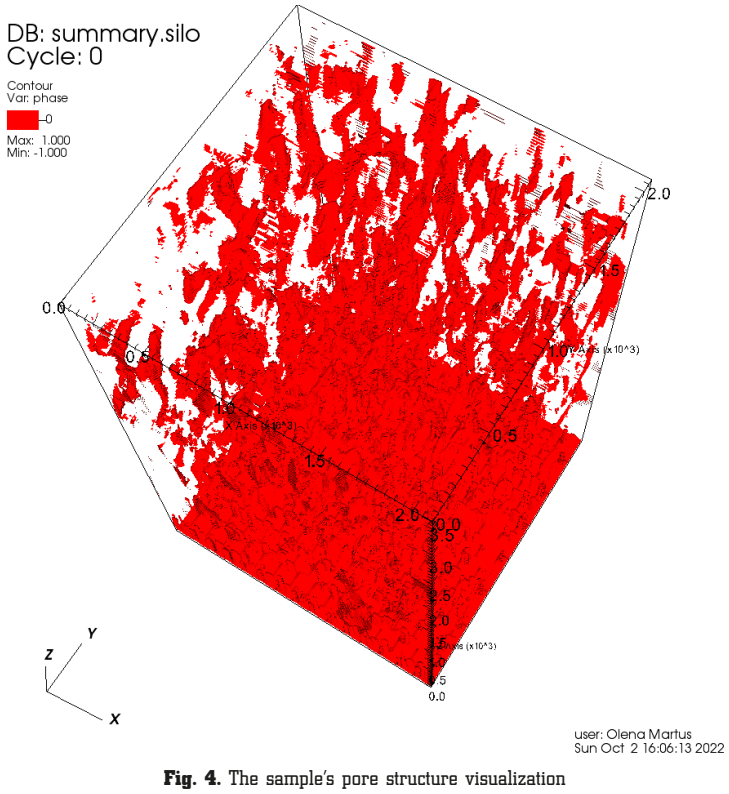

Fig. 4. The sample's pore structure visualization

As it is possible to see, the software works and displays the processes taking place in the pore space. The question remains of a convenient interface that will ensure wide use of this promising project. The development of this research lies in the field of information technologies. At the next stage, it is necessary to create a complete software product. This product should combine all the stages described in this paper, including three-dimensional interpretation of the sample structure based on MRI images, calculation of the physical parameters of the sample (porosity, absolute and phase permeability), determination of the representative elementary volume. At the final stage of data processing, the function of outputting the results to the visualizer module is required, which will allow graphical interpretation of mass transfer processes in the reservoir rock and scaling of the results to the entire horizon.

Thus, this work studied and tested the workflow (Fig. 5), which leads to obtaining a 3D visualization of the internal micropore structure of the reservoir rock sample. This provides an entirely new perspective on the reservoir evaluation process, as the engineer will have an alternative methodology to evaluate reservoir flow properties such as porosity, permeability, etc. However, there is still a need to introduce the proposed algorithm into a user-friendly interface that makes the workflow convenient. In addition to this, the workflow should not be used in isolation, the authors recommend that at this stage it should only be considered as a validation tool for a more accurate interpretation of the traditional reservoir assessment methodology.

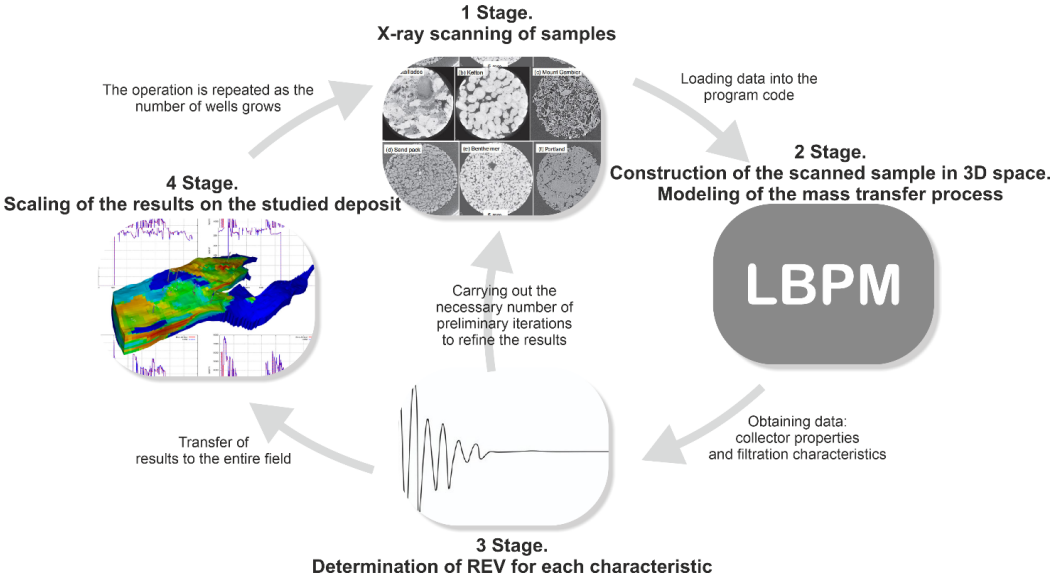

Fig. 5. Work process implemented by software

The further development of this study lies in the massive testing work aimed at the calibration of all the described procedures and optimization of the amounts of time spent and samples taken.

4. Conclusions

As a result of the research, an improved methodology for assessing the reservoir properties of the formation is presented. The improvement consists in finding collector properties by studying the core sample at the microscale level, namely: scanning the sample with MRI and its subsequent reproduction in 3D space. The results obtained at the microscale level must be taken into account and reconciled with the collector properties obtained at other scaling levels due to REV. Software architecture is proposed, which will allow obtaining a qualitatively new representation of the reservoir. A feature of the architecture that explores the sample at the microscale level is the adaptation of the considered open source software on GitHub into an easy-to-use program for the non-programming engineer. The architecture of the program provides for convenient data entry, display, and output of results, the latter of which should be applied in programs specializing in large scales. The proposed technique at this stage can be used to verify the results of core laboratory studies according to current methods.

Conflict of interest

The authors declare that they have no conflict of interest in relation to this research, including financial, personal, authorship, or any other nature that could affect the research and its results presented in this study.

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Availability of data

Data will be provided upon reasonable request.

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