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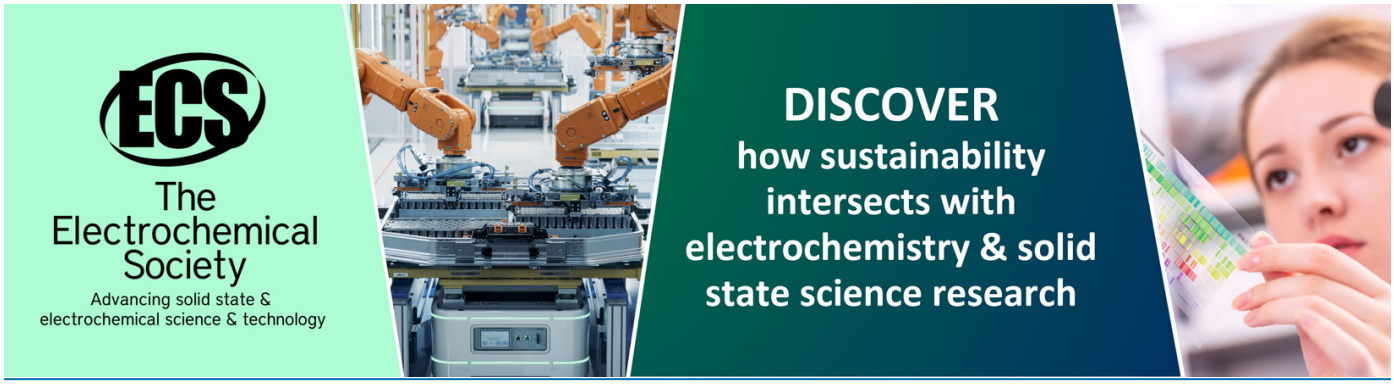

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Study of the pattern of fluid flow in the pore space of kerogen-clay-carbonate-siliceous rocks of Bazhenov Suite

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Abstract. The paper is devoted to a numerical study of the features of fluid redistribution in the pore space of an unconventional hydrocarbon reservoir of the Bazhenov Suite (West Siberian oil and gas basin). We analyzed the filtration properties of the microscale layers of the formation with composite structure and multiscale porosity using the triaxial compression test. The simulation results showed that the flow rate of the pore fluid is determined by a set of parameters, including the rate of change of local stresses, the permeability of the skeleton, the viscosity of the pore fluid, reservoir pressure and the size of its differential region. We revealed the dimensionless combination of these parameters that uniquely determines the value of the fluid flow rate. The results of the study can be used in assessing the contributions of the structural elements structure to reservoir production capacity.

1. Introduction

The development of digital twins of oil and gas reservoirs is currently a key stage in creating new technologies for the exploration and exploitation of unconventional hydrocarbon deposits [1-3]. Virtual testing of digital twins allows one to obtain important information about the stress fields in the reservoir and adjacent rocks, and their change during a particular impact on the reservoir [4,5]. This makes it possible not only to assess the effect of technological impact but also to determine the optimal methods and modes of action. The concept of digital twins is based on multiscale mathematical models of fractured-porous fluid-saturated media (oil and gas reservoirs), which are then implemented in the framework of numerical techniques. A key requirement for such a model is coupled formulation, namely, the model has to take into account the mechanical interaction between the solid-phase skeleton and the mobile interstitial fluid.

Coupled mechanical models are relevant, first of all, for predicting the results of impacts on shale formations. Formations of this kind are characterized by many physical and mechanical features that fundamentally distinguish them from traditional reservoirs [6-8]. Striking representative is the Bazhenov Suite of the West Siberian oil and gas basin [9,10]. This is one of the most studied, yet most unpredictable formations of petroleum geology in Russia. Hydrocarbon reservoirs of the Bazhenov Suite are among the most important sources of substitution for decreasing production volumes from traditional fields [11]. Estimates of the hydrocarbon resources of this unconventional reservoir range from 600 million to 30 billion tons. This determines the huge interest in building geomechanical models and their use for analyzing the influence of technological impacts and predicting productivity.

Bazhenov Suite has many features that should be taken into account when developing adequate physical and mechanical models. These include, first of all, the multiscale structure of rock and the

complex anisotropic mechanical properties of its structural elements. A fundamentally important feature is the large interval of the characteristic sizes of pores, channels, and other fluid-saturated discontinuities. These discontinuities form the interconnected system and participate in fluid flow/diffusion processes. A large fraction of discontinuities belongs to the nanometer size range (<100 nm). Nanoscale discontinuities connect microscale pores and largely determine the intensity of interstitial fluid redistribution in the rock. Changes in the permeability of the nanoscale pore space may have a significant influence on the total productivity of the formation [5,12].

There are well-known difficulties in direct experimental study of the permeability of rocks of the Bazhenov Suite and its dependence on the stress state. The main problem is the spontaneous destruction (stratification) of the core samples under ordinary P-T conditions. This determines the relevance of developing computer models and their application for theoretical (mainly numerical) estimation of the yield of light (fluid) hydrocarbon fractions. Such estimates are especially in demand for predicting changes in the production capacity of a section of a bed when its stress state changes.

The purpose of the present work is the computer-aided analysis of the production capacity of the main (microscale) structural element of kerogen-clay-carbonate-siliceous rocks of the Bazhenov Suite.

2. Model description

We carried out the study with the use of the coupled mechanical model of the main microscale structural element of the Bazhenov Suite rock [13]. This element has a composite structure and consists of a clay matrix with embedded organic substances as layered inclusions (volume fraction is 20÷25%). To model the matrix material, we used the typical mechanical characteristics of kaolin clays [14]. Data on the mechanical properties of microscale layered organic inclusions are extremely limited and contradictory. We assume the mechanical characteristics of organic inclusions close to the corresponding characteristics of xylite (macroscopically plastic and low-strength lithotype of brown coal in the form of small layers and lenses in peat and coal beds).

The model takes into account that interstitial fluid in the main structural element is contained: 1) in micropores (large cavities of a characteristic size up to 10^{-6} m filled with both heavy and light hydrocarbon fractions); 2) in "nanopores" (characteristic size is tens of nanometers). Micropores are contained in a clay matrix. Nanoporous are both a matrix and organic inclusions. Micropores and nanopores are integrated, that is, forming a single network in which interstitial fluid flows.

The model takes into account not only light but also heavy hydrocarbon fractions in micropores. The heavy fractions are assumed to be viscoelastic and forming a kind of permeable “skeleton” in the micropore volume. The pore space of such a “skeleton” in the micropore is filled with light fractions, and its permeability is several orders of magnitude higher than the permeability of the clay matrix.

We modeled representative microscale 2D samples of the main structural element of Bazhenov Suite rock. The shape of the samples was assumed to be square, the side length was 10 μm. Modeling was carried out with the use of the hybrid method of permeable discrete elements [15,16]. This numerical method combines the method of deformable discrete elements and finite difference method and allows one to simulate the mechanical behavior of permeable fluid-saturated materials with taking into account the deformability of both solid-phase skeleton and mobile interstitial fluid. Figure 1 shows the structure of a typical model sample. The diameter of the discrete elements modeling the sample components was assumed to be 0.05 μm.

The mutual influence of the deformation of the solid-phase skeleton of a discrete element and change in “intraelement” pore pressure is taken into account by calculating the current volume of pore space using the constitutive equations of the Biot’s linear model of poroelasticity [17,18]. Clay matrix and organic inclusions are considered as elastic-plastic. To describe their elastic-plastic behavior, we used: 1) Hooke's law for isotropic poroelastic materials; 2) a non-associated model of plastic flow with a modified Mises-Schleicher criterion (a modified Nikolaevsky model) written in terms of Terzaghi effective stresses. The modified Drucker-Prager criterion was used as a criterion for local fracture (fracture was modeled by breaking the bond between the elements). Modified Drucker-Prager criterion also formulated in terms of the effective Terzaghi stresses. Detailed information on the constitutive

relations and features of the coupled discrete element-finite difference model of permeable fluid-saturated materials is given in [15].

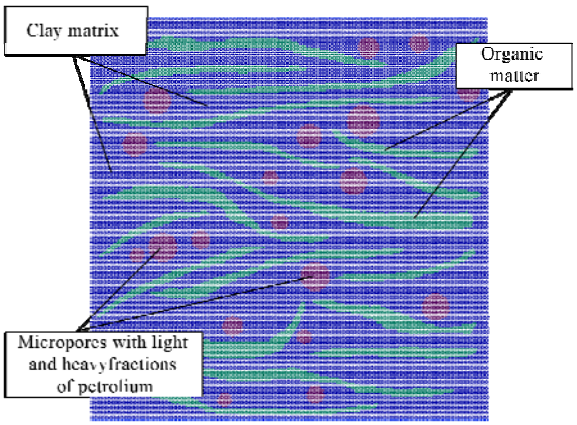

Figure 1. The structure of the sample modeling a representative microscale volume of the main structural ("bearing") rock element.

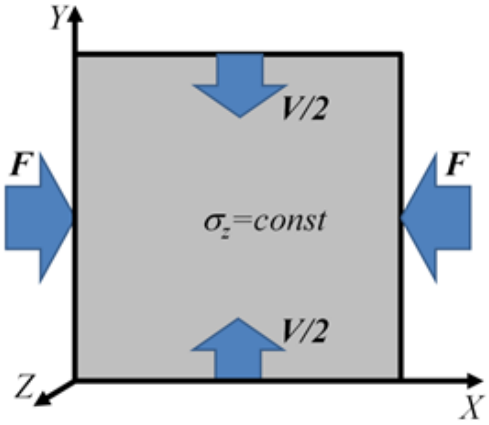

Figure 2. Scheme of loading of the model sample.

The discrete elements modeling micropores simulate a "heavy fraction skeleton" (HFS) and are described using a coupled model of permeable viscoelastic materials [19]. Note that HFS elements could "repack" during pore deformation due to the low adhesion strength (its value was estimated based on the magnitude of the surface tension force) and form a new adhesive bond when coming into contact with a neighbor.

The mechanical properties of discrete elements modeling the above components of this natural composite are given in [13].

Light fractions of hydrocarbons in the pore space a discrete element modeling a clay matrix, organic inclusion, or "heavy fraction" in a micropore were modeled implicitly and were characterized by integral parameters: mass, density, pore pressure. The redistribution of light fractions in the pore space of the sample was described by means of a numerical solution of the Newtonian fluid transport equation [20] in a modified form that takes into account the finite propagation velocity of disturbances. The Newtonian fluid transport equation was solved by the finite volume method on an ensemble of discrete elements.

The sample was modeled in the plane stress approximation (Figure 2). We applied a generalized formulation of this approximation (the out-of-plane axial stress σ_z is nonzero and constant).

The initial stress state of the sample was specified according to the stress state of the bed at a given depth. A compressive load was applied to the upper and lower surfaces of the sample along the Y-axis, and the side surfaces along the X-axis. The specific values of these loading forces (σ_y and σ_x) correspond to the values of the lithostatic and horizontal / side pressures in the bed at a given depth, respectively. The compressive stress σ_z along the Z-axis was equal to the side pressure σ_x.

We simulated the triaxial compression of a prestressed fluid-saturated sample (Figure 2). A constant velocity V along the Y-axis was assigned to the elements of the upper and lower surfaces. The side pressure value $\sigma_x=\sigma_z$ was kept constant. Thus, we simulated the axial loading along the "gravity axis" at a constant side pressure equal to the horizontal pressure in the bed at some depth.

3. Results and discussion

Estimation of the power of yield of light (flowing) hydrocarbon fractions when the stress state of the reservoir section changes is among the key components of the analysis of kerogen-clay-carbonate-siliceous rocks as hydrocarbon reservoirs. An informative method of conducting such studies is triaxial compression of fluid-saturated samples using permeable hydrological conditions on the

surfaces (a predetermined constant fluid pressure is maintained on surfaces).

We performed a computer simulation of such a test for representative microscale samples of the main structural element of the rock (Figure 1). We considered three values of side pressure $\sigma_x=\sigma_z$ corresponding to different depths (10 MPa ~ 1 km, 20 MPa ~ 2 km, 30 MPa ~ 3 km) within the typical depth range for the hydrocarbon reservoir of the Bazhenov Suite. The boundaries of the sample were permeable to the fluid and maintained a constant fluid pressure $P_{\text{pore}}^{\text{res}}$ equal to hydrostatic pressure at a considered depth. Axial deformation causes a continuous increase in pore pressure and pore pressure gradient in the representative volume and results in the continuous fluid outflow from the sample. We measured the fluid outflow through the surfaces during compression.

Figure 3 shows typical examples of diagrams of fluid outflow from a model sample of the main structural element of the rock at different values of axial loading velocity V (side pressure $\sigma_x=\sigma_z$ corresponds to a depth of 2 km). Here, the fraction of the released fluid is determined as the ratio of the mass of the released fluid to the mass of interstitial fluid in the sample before deformation at a constant speed. One can see that the curves corresponding to different velocities have the same type of profile. After the initial non-linear section, the fluid outflow rate reaches a steady-state value and then remains constant. Small occasional "oscillations" on the curve correspond to the formation of local cracks of submicron length in the kaolin matrix.

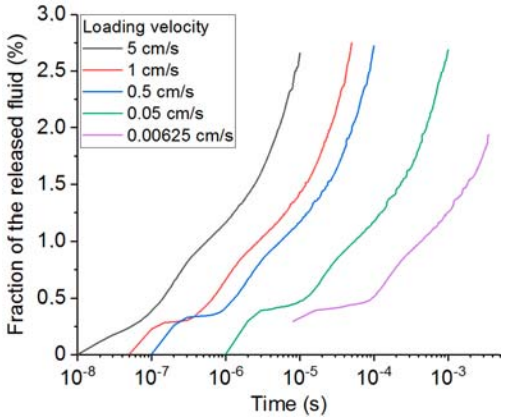

Figure 3. Typical dependences of fluid outflow from a model sample under the condition of triaxial compression (vertical loading at a constant velocity and constant side pressure 2 MPa).

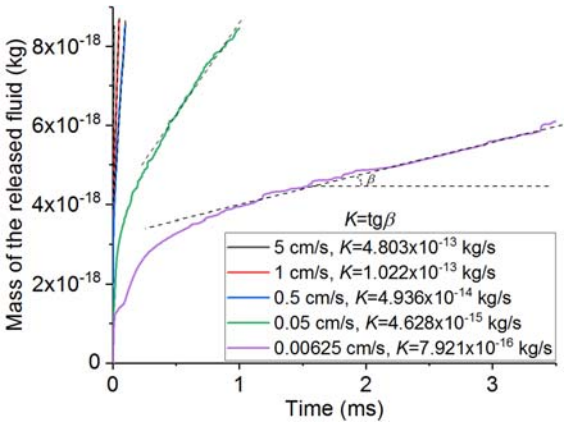

Figure 4. Typical dependences of fluid outflow from a model sample (the same curves as in Figure 3) in linear time coordinate.

Figure 4 shows the dependences of the fluid outflow from the sample on time in the linear time coordinate. The slope of the straight line K, approximating the linear section (steady-state fluid flow at a constant rate), uniquely determines the flow rate (in units of kg/s) at the corresponding loading velocity. The ratio of the flow rate to the area of the lateral surfaces of the sample through which fluid flows out into the surrounding medium determines the power density of this flow at the corresponding loading velocity (or strain rate).

The results of a parametric study showed that the outflow power density of the pore fluid is a function of the strain rate $\dot{\varepsilon}=V/H$ (H is the height of the sample) as well as of other system parameters including the permeability of the matrix skeleton κ, the viscosity of the pore fluid η, the surrounding (reservoir) fluid pressure $P_{\text{pore}}^{\text{res}}$ and characteristic length of fluid flow (half-width of the sample) L. Analysis of the simulation results revealed a dimensionless combination of these parameters, which uniquely determines the outflow power density of the pore fluid at given values of side pressure and reservoir pressure. It is formulated similar to the Darcy number:

$$Da = \frac{\eta L^2}{\kappa P_{\text{pore}}^{\text{res}}} \dot{\varepsilon} \,. \tag{1}$$

We found that the dependence of the outflow power density of the pore fluid on *Da* is approximated with good accuracy by a simple function close to linear (Figure 5).

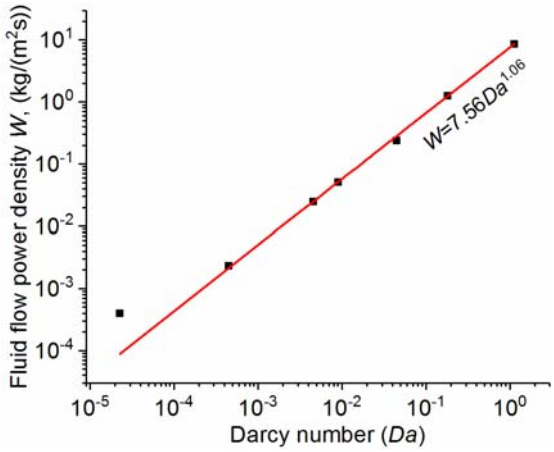

Figure 5. The dependence of the fluid outflow power density on the "Darcy number" at a side pressure corresponding to a depth of 2 km.

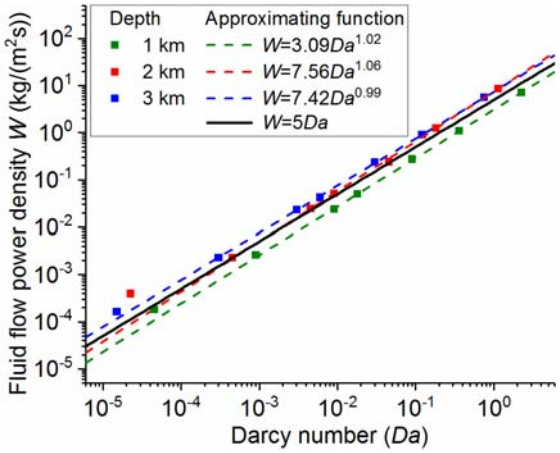

Figure 6. The generalized dependence of the fluid outflow power density on the "Darcy number" obtained by averaging data for various lateral pressures (various depths).

The dependences of the fluid flow rate on the Darcy number for other formation depths (1 km and 3 km) were obtained similarly. The values of side pressure on the sample and fluid pressure at the external boundaries in both cases correspond to the horizontal and reservoir pressures at the corresponding depths. Colored squares in Figure 6 show the numerically derived power density values obtained at various values of *Da* and formation depth. Each dashed line of the corresponding color shows the function approximating a set of numerically derived points at the specified depth.

One can see from Figure 6 that the above dependences of the fluid flow rate on the Darcy number at various depths can be approximated with satisfactory accuracy by a single linear function. In other words, the fluid flow rate depends on reservoir pressure but not on the formation depth (this conclusion holds at least within the considered range of formation depths). The "single" linear function is marked in black in Figure 6. This approximating function is common for the various depths considered and can be used in assessing the contributions of various structural elements to the filtration properties of the reservoir.

4. Conclusions

The Bazhenov Suite of the West Siberian oil and gas basin is recognized as one of the most promising objects for oil production. The oil reservoir in the Bazhenov formation is fundamentally different from traditional fields, which significantly complicates the development of this deposit. The efficient development of this non-traditional reservoir needs many fundamental and practically important tasks to be solved. One of them is the building of digital models of the structural elements of the formation and their use to predict the rate of redistribution of light hydrocarbon fractions under the conditions of local changes in the stress state. In the present study, such estimates are obtained for the main microscale structural element of the reservoir.

We numerically showed that the power density of pore fluid flow induced by a dynamic change in the stress state of the main structural element of the rock is a nonlinear function of the applied strain rate, the size of the loaded region, the horizontal pressure in the bed and the reservoir pressure, as well

as the viscosity of the pore fluid and the permeability of the skeleton. We determined a dimensionless combination of these parameters, which uniquely determines the fluid outflow power density at a given value of reservoir pressure. This dimensionless parameter is similar to the Darcy number. The obtained dependence is approximated with good accuracy by a linear function and is common for various depths and reservoir pressures. This allows one to apply it when conducting a qualitative and quantitative assessment of the contributions of various structural elements to the production capacity of the formation. The results of the study are also relevant for solving problems of dynamic change in the stress state of a bed using traditional (uncoupled) mechanical models in which the value of pore pressure is assumed to be constant and equal to local reservoir pressure.

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