A system of artificially created fractures formed during multi-stage hydraulic fracturing in a low-permeable gas-saturated reservoirs has been investigated in this study. The task addressed is to parameterize the object under consideration given limited input geomechanical information.

The results of hydraulic fractures modeling have been obtained, as well as their geometric and filtration parameters, by using analytical and explicit numerical methods. Interpretation of the findings revealed the limitations in analytical methods when considering the geomechanical properties of rocks; specifically, their reservoir and geomechanical heterogeneities and stimulation design. The consequence is the greatly increased uncertainty in production forecasting because fractures are represented by average values of key parameters (L = 120–330 m, w = 2.4–7.8 mm) for determining well productivity.

The explicit method demonstrated higher flexibility and adaptability depending on the available input data. The average results, which were obtained by applying both methods, showed similarity between key parameters (L = 199–339 m, w = 7–10 mm, Cf = 774–1098 mD*m), which confirms these methods' validity. However, the ability of the explicit modeling approach to provide a detailed description of key fracture parameters, including 3D geometry, variation of fracture width (w = 3–11 mm), and proppant saturation over the fractured area (Cp = 75%), gives a higher priority to this method during research.

The use of an explicit method, in contrast to the analytical one, makes it possible to determine the asymmetry of the fracture flanks, relative to the direction of the minimum horizontal stress, the change in thickness and permeability along the fracture, the distribution and concentration of proppant. All this leads to an uncertainty ranges reduction in the production forecast from horizontal wells with multi-stage hydraulic fracturing, during the development of shale reservoirs. This is the next step for further use of the results

Keywords: explicit modeling, reservoirs with low permeability, multi-stage hydraulic fracturing, shadow fracturing effect

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PATTERNS IN THE FORMATION AND PARAMETERIZATION OF THE FRACTURE SYSTEM EMERGING DURING A MULTI-STAGE HYDRAULIC FRACTURING IN TIGHT RESERVOIRS UNDER DIFFERENT MODELING APPROACHES

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1. Introduction

In the oil and gas industry, the problem of falling reserves replacement coefficient from traditional reservoirs is becoming more and more noticeable. It is because of this that the share of deposits with low permeability in the structure of explored global hydrocarbon resources is increasing. Low-permeability reservoirs today actually determine the future dynamics of production. In this regard, research into increasing the efficiency of the development of such reservoirs remains relevant; moreover, it becomes more important for the further development of the industry.

However, compacted reservoirs are characterized by a complex geological structure, heterogeneity of filtration and capacity properties, and a change in the stress-strain state. Under these conditions, horizontal drilling and multi-stage hydraulic fracturing of the formation is a necessary condition for achieving an economically feasible level of production. Designing it requires a large array of input data and modern tools for reproducing the growth of fractures in space, their direction, thickness, permeability, and interaction with the matrix and with each other. The combination of these factors significantly complicates the prediction of well productivity. Therefore, the ability to reliably describe the parameters of the fracture system directly determines the effectiveness of technological solutions and the economic feasibility of developing low-permeability deposits. That is why the scientific topic related to the reliable description of the parameters of artificially created fractures during multi-stage hydraulic fracturing is key when designing the development of unconventional deposits.

Analytical models such as KGD (Khristianovic-Geertsma-de Klerk) and PKN (Perkins-Kern-Nordgren) have traditionally been used for the initial assessment of the parameters of the resulting fractures, but their application is limited by simplifications. This applies to variations in geomechanical properties, changes in stresses during reservoir depletion, the presence of natural fracturing, which has a significant impact on the geometry, orientation and permeability of fractures. But on the other hand, they allow for a quick assessment of the parameters of fractures, such as half-length, width and permeability, after the hydraulic fracturing. Despite the simplicity and significant simplification of processes, analytical approaches remain in demand due to the speed of calculation, low requirements for the amount of input data, and the possibility of operational optimization with a minimum number of sensitivity parameters. However, it should be noted that modern conditions for the development of low-permeability reservoirs increasingly require a more detailed and physically based spatial model of the fracture system, taking into account the geomechanical properties of rocks. That is why there is growing interest in numerical methods that make it possible to reproduce the three-dimensional geometry of fractures, the interaction between them, determine the distribution of proppant and evaluate the change in permeability over the area and in time. However, geomechanical modeling requires a significant amount of input data, namely the stress profile, the value of the modulus of elasticity along the wellbore, and in the inter-wellbore space, strength parameters and characterization of natural fracturing, if it exists. Geomechanical data are typically absent or fragmentary because of the high cost of studies.

Thus, research into methods for modeling hydraulic fracturing processes in low-permeability reservoirs and their improvement and adaptability to available geological and geomechanical information is relevant for increasing production efficiency. This could reduce technological risks, improve forecasting capabilities, and optimize costs.

2. Literature review and problem statement

Results of analytical modeling of the fracture system using the KGD and PKN methods are reported in [1]. Analytical models do not take into account complex factors, such as heterogeneity of rock properties over the area, plastic deformation and the presence of natural fracturing. This significantly limits the scope of their application in complex geological conditions. When constructing such models, it is necessary to take into account the complexity of the geological structure, the increasing role of heterogeneity of the distribution of reservoirs, the influence of the stress-strain state of the rock, and the current distribution of the stress field. Therefore, the use of classical KGD and PKN models is insufficient for predicting production from compacted reservoirs since they do not take into account all of the above factors. An option for overcoming such difficulties can be numerical methods for modeling fractures after hydraulic fracturing. They allow us to clearly reproduce the geometry of fractures, the mechanics of their growth, the resulting thickness and distribution of proppant, which affects the permeability of fractures and well productivity.

This is the approach used by the authors of [2], which demonstrated significantly higher accuracy of forecasted productions generated on 3D numerical models that took into account stress gradients and heterogeneity of reservoir properties, compared to traditional analytical approaches. Similarly, in study [3], the authors emphasized that only explicit numerical modeling can assess the impact of natural fracturing on the geometry and properties of artificially created fractures after multi-stage fracturing. This has a significant impact on the predicted stimulation area and, as a result, the total stimulated volume. However, the issue of using explicit methods with limited input geomechanical information remains unresolved. For example, the authors of work [4] argued that when ignoring plasticity and the general stress-strain state of rocks, analytical models tend to overestimate the opening of fractures, which leads to a negative impact on the accuracy of the forecast. However, often for deposits, geomechanical studies were not conducted, or were performed fragmentarily, which significantly complicates the application of an explicit approach to modeling multi-stage hydraulic fracturing, due to significant uncertainty and the need to use estimated values for some parameters.

The relevance of intensive development of low-permeability reservoirs is increasing due to the depletion of reserves of traditional reservoirs. Total natural gas reserves of unconventional reservoirs are estimated at 5.4 trillion m^3, according to [5]. The largest gas field of this type is Yuzivske. The authors of work [6] estimate its total reserves of various categories at 2 trillion m^3, and the potential annual production is close to 10 billion m^3. However, geomechanical studies have not been conducted in this area.

For such conditions and to solve the problems of the lack of geomechanical information, a tool is needed that contains a library of templates with the physical values of these parameters. As such a tool, the Kinetix Shale (USA) software product developed by SLB could be used for explicit three-dimensional modeling of fracturing processes under various geological conditions. In contrast to the analytical PKN and KGD models, which are based on a simplified representation of the geometry of fractures, Kinetix is based on a comprehensive approach. This approach allows us to take into account the anisotropy of rocks, the heterogeneity of geomechanical parameters, the interaction of natural fracturing with fractures created after fracturing, which is shown in [7]. The basis of the three-dimensional explicit model is the Unconventional Fracture Model (UFM), which combines the advantages of three-dimensional numerical models with discrete ones. This makes it possible to reproduce the shape of fractures that will change over time under the influence of the design of the fracturing, the number of stages, the volume of fluids at each stage, and also to evaluate the effect of shadow interaction between fractures. In works [8, 9] it is shown that the efficiency of each subsequent stage decreased precisely due to the shadow effect of the previous stages. In [10], the results of modeling the processes of transporting fluids and proppant in fractures are reported; this is critical for understanding the productivity of the well, the longevity of production. The results of study [11] showed that the explicit method makes it possible to optimize the location of perforation clusters along the horizontal part of the well, to conduct a sensitivity analysis for different injection modes, volumes and supply of fracturing fluid, and proppant mass. The possibility of using the explicit modeling method under conditions of limited geomechanical information can be solved by using typical templates.

A feature of explicit modeling of fractures, after hydraulic fracturing, is the possibility of integration and calibration on the results of well testing on the modes and interpretation of the derivative of PRC (pressure recovery curve). For example, the authors of[12] used microseismic monitoring and injection curves to calibrate an artificial fracture network created using an explicit model. This approach allowed them to adjust the model and reduce the uncertainty in predicting the geometry and parameters of fractures. If we compare Kinetix with the classical analytical models PKN and KGD, we can conclude that explicit modeling provides a more realistic reproduction of the processes of formation of a fracture system in complex compacted reservoirs, as mentioned in [13, 14]. At the same time, analytical models describe the fracture with an idealized geometry (rectangular or elliptical shape). An important aspect is the shadow effect between stages, which manifests itself in the change of the stressed-strained state near the wellhead after each stage of fracturing, which will have an impact on subsequent stages. This relationship was described in study [15], in which during the modeling of multi-stage hydraulic fracturing, each subsequent stage was characterized by lower efficiency compared to the previous one.

Our analysis of classical hydraulic fracturing models (KGD, PKN) revealed that despite their analytical convenience, they have a common conceptual limitation, namely the inability to adequately describe the propagation of fractures under real geological conditions. This limitation is manifested in ignoring the spatial heterogeneity of the physical and mechanical properties of rocks, detailed parameterization of the conditions for hydraulic fracturing, and the interstage shadow effect, which has a significant impact on the geometry and dynamics of fracture development. Thus, the combination of these shortcomings forms a limitation in the use of classical models for modeling hydraulic fracturing processes in complex and heterogeneous environments, which necessitates the development or modification of approaches that can take these factors into account.

Thus, one can note that analytical models are significantly inferior to modern numerical approaches when predicting the geometric and filtration characteristics of fracture systems. Recent studies demonstrate the advantages of an explicit three-dimensional modeling method, which makes it possible to more accurately reproduce the geometry of fractures and reduce uncertainty when forecasting production.

3. The aim and objectives of the study

The aim of our study is to substantiate an approach to explicit numerical modeling of the formation and propagation of a network of fractures during multi-stage hydraulic fracturing (HF) in tight reservoirs under conditions of a shortage of geomechanical data, and to assess the inter-stage shadow effect. This will make it possible to increase the accuracy of predicting the parameters of fractures and improve the assessment of the productivity of horizontal wells developing tight reservoirs.

To achieve the goal, the following tasks were set:

– to calculate the geometric and hydrodynamic parameters of fractures using analytical methods;

– to build a 3D geological model of the deposit, integrate geophysical survey data, petrophysical interpretation and description of the available core;

– to construct an explicit numerical model to reproduce the process of formation of the fracture system taking into account the heterogeneity of reservoir and geomechanical properties;

– to determine the proppant coverage along the fractures and its spatial distribution.

4. Materials and methods

The principal hypothesis assumes that numerical modeling of the multistage hydraulic fracturing system in sealed reservoirs, in contrast to classical analytical models (KGD, PKN), provides a more correct description of the processes of fracture initiation and propagation. This is due to the possibility of an explicit approach to take into account the spatial heterogeneity of the physical and mechanical properties of rocks and the mutual shadow effect between fractures. It is additionally assumed that in the absence of complete geomechanical information, the use of generalized templates could allow us to reproduce the key patterns of fracture formation during multistage hydraulic fracturing. It is expected that the combination of explicit numerical modeling with template geomechanical data could serve as a practical tool for interpreting and predicting the effectiveness of multistage hydraulic fracturing under conditions of limited input information.

The numerical model is built for a typical sealed gas-saturated reservoir. The main parameters used in the modeling are based on public reports by the State Service of Geology and Subsoil, literary sources, and are given in Table 1.

Table 1

Geological and geophysical source data

Parameter	Value
Depth of reservoirs	2500–3500 m
Thickness of productive horizon	20–45 m
Porosity	6–12%
Permeability	0.01–0.1 mD
Reservoir type	Compacted sandstones and siltstones
Saturation type	Gas
Reservoir temperature	90–120°C
Reservoir pressure	25–35 MPa

To describe the geomechanical properties of strata typical for the Dnieper-Donetsk depression, the following averaged parameter values were applied and summarized in Table 2.

Kinetix uses available geomechanical information and makes it possible to increase the accuracy of predicting the geometry of the artificial fracture system, optimize the parameters of multi-stage fracturing. In order to compare analytical and explicit methods, modeling was carried out for both methods. The explicit three-dimensional model (UFM) was used to reproduce the real geometry of the fracture taking into account the available geomechanical information and the parameterized fracturing. Analytical models (PKN/KGD) were used to compare and evaluate the differences. It should be noted that the PKN type model is used for thin layers, with a constant fracture height. The KGD model is more suitable for thick layers where the fracture expands mainly in width. These analytical models describe the geometry of the fracture, namely its length, width, based on the averaged geomechanical properties of the rocks, the duration of the fracturing, and the absorption of fluid by the formation. Both analytical models use the following parameters:

– effective modulus (Young's modulus)

$$E' = \frac{E}{1-\nu^2}; \tag{1}$$

– fluid loss in the reservoir

$$Q_{loss} = A_f * \frac{C_L}{\sqrt{t}}; \tag{2}$$

– effective fluid flow in the fracture

$$Q_{eff} = Q - Q_{loss}. \tag{3}$$

The fracture length for the KGD model, according to [7] is determined from the formula

$$L = \left(\frac{2.1 * Q_{eff}^3 * E'}{h^4 * \mu}\right)^{\frac{1}{5}} * t^{\frac{3}{5}}. \tag{4}$$

The fracture width for the KGD model, according to [7] is determined from the formula

$$\omega_{\max} = 2.1 * \left(\frac{Q_{eff} * \mu}{E' * h}\right)^{\frac{1}{5}} * t^{\frac{1}{5}}. \tag{5}$$

The fracture length for the PKN model, according to [16] is determined from the formula

$$L = \left(\frac{Q_{eff}^3 * E'}{\mu * h^3}\right)^{\frac{1}{5}} * t^{\frac{3}{5}}. \tag{6}$$

The fracture width for the PKN model, according to [16] is determined from the formula

$$\omega_{\max} = 0.88 * \left(\frac{\mu * Q_{eff}}{E'}\right)^{\frac{1}{5}} * t^{\frac{1}{5}} * h^{\frac{2}{5}}, \tag{7}$$

where:

– Q – fluid flow rate, m^3/s;

– E`– Young's modulus for the formation, Pa;

– C_L – fluid absorption coefficient by the formation, $m/s^{1/2}$;

– t – injection time, s;

– h – fracture height, m;

– μ – fluid viscosity, Pa*s.

Table 2

Geomechanical parameters (average values)

Parameter	Value
Modulus of elasticity E, MPa	20000–30000
Poisson's ratio (ν)	0.22–0.28
Compressive strength, MPa	80–120
Tensile strength, MPa	3–7
Minimum horizontal stress	26–34 MPa
Maximum horizontal stress	32–42 MPa

Analytical models of the KGD and PKN types are physically justified and are used to calculate vertical fractures in massive formations and for long fractures in thin formations, respectively. However, a three-dimensional digital model of the reservoir provides greater flexibility and makes it possible to take into account the spatial heterogeneity of the pore space properties and interstage interference. To build a digital spatial model of the reservoir, geophysical well data were used, in particular, gamma-ray logging (GR), density logging (RHOB), acoustic logging (DT), and neutron-porosity logging (NPHI). Based on these curves, a petrophysical model of the distribution of reservoir properties was built, taking into account lithology and zonal division. A previously prepared tectonic-structural framework was used to distribute petrophysical properties.

Reservoir conditions can be characterized as typical with permeability below 0.01 mD and porosity in the range of 10–12%, which is consistent with the properties of compacted sandstones. Due to the limited geomechanical information, including microseismic observations, mini-fracture results and rock stress measurements, fracture modeling was performed under limited input conditions using Kinetix templates. Table 3 summarizes the input parameters for fracturing simulation in the Kinetix environment.

Table 3

Input parameters for hydraulic fracturing simulation in Kinetix environment

Parameters	Value	Note
Well length	1600	Gorizontal section
Number of stages	8	Stages
Fluid type	Polymeric	Viscosity at 85º–40 cPz
Proppant type	20/40	Quartz sand
Proppant concentration	200–800	Increase from 200 kg/m^3 to 800 kg/m^3
Injection fluid volume	250	Calculated with a flow rate of 2 m^3/min
Stage duration	127	min
Injection rate	2.0	m^3/min

The hydraulic fracturing model was constructed in Kinetix, using available geological and geomechanical data.

The use of rock property templates from similar formations allows for confidence in the reliability of the results. The templates available in Kinetix are given in Table 4.

Explicit modeling of hydraulic fracturing allows us to visualize the three-dimensional configuration of the resulting fractures, estimate their half-length, thickness, and permeability. It is also possible to conduct a sensitivity analysis to changes in matrix permeability and to estimate asymmetry under the condition of prior depletion of the deposit, which will affect the stress-strain state of the rocks. Thus, it is possible to model the multi-stage hydraulic fracturing process with sufficient detail, despite the limited geomechanical information, and to assess the effectiveness of the stimulation by predicting production on a hydrodynamic simulator.

Table 4

Geomechanical rock property templates in Kinetix

Rock type	Modulus of elasticity, GPa	Poisson's ratio	Specific weight	Fracture propagation resistance, kPa*$\sqrt{m}$
Sandstone	38.74	0.20	2.65	1319
Argyle sandstone	24.06	0.25	2.50	1319
Alemnite	9.14	0.30	2.65	1978
Shale	30.98	0.35	2.30	1099
Dolomite	54.86	0.28	2.95	2637
Limestone	28.88	0.30	2.71	2637
Cretaceous	20.68	0.30	2.65	549

Gamma-ray logging (GR), neutron-density (RHOB), and induction logging were used to identify the lithological composition of the rocks. The set of logging curves used in the study is shown in Fig. 1.

Based on the logging curves, low-radioactivity intervals were identified, which are characteristic of pure sandstones. At the same time, intervals with increased radioactivity were identified as shale.

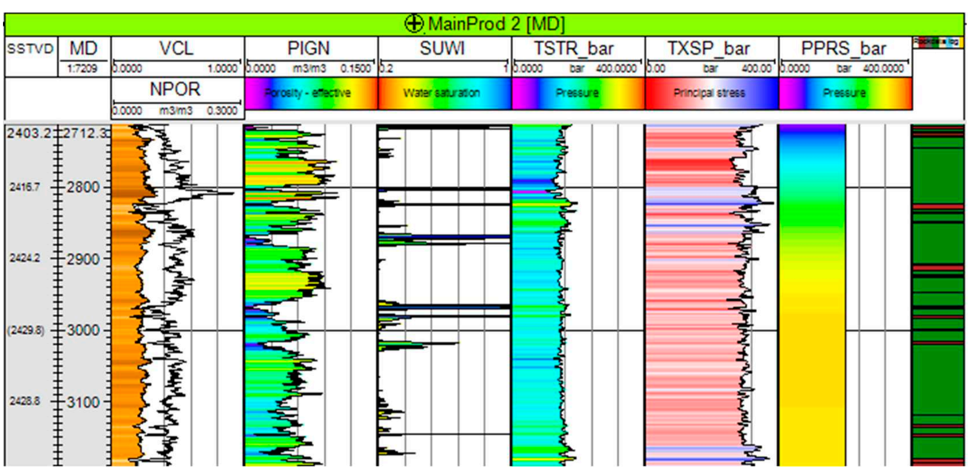


Fig. 1. A set of logging curves for identifying lithological composition in Petrel

5. Results of studies on parameterization of the fracture system

5. 1. Calculation of fracture parameters using analytical methods

The results of calculations using the analytical models KGD and PKN are given in Table 5.

For the KGD model, the fracture length is 119.5 meters, while for the PKN model it is as much as 332.1 meters. This difference between the lengths is explained by the assumptions adopted in each of the models, according to which these dependences were calibrated. The KGD model assumes a fracture with a square cross-section and is used mainly for massive deposits, where the fracture grows in height. The PKN model is focused on a fracture with a significant length and a thin vertical opening due to the small thickness of the deposit. The fracture width for the KGD model is 2.41 mm, compared to 7.78 mm for the PKN model. This confirms the assumption that within the PKN model the fracture is longer and wider, which contributes to greater contact of the proppant with the stimulated pore volume. However, as can be seen from the data given in Table 5, the results of analytical models are limited to determining the length and thickness of the fracture, without the ability to assess the effect of multistage, asymmetry or proppant distribution along the fracture. The PKN and KGD type analytical model cannot be fully used to predict the production from a horizontal well with multistage hydraulic fracturing.

Table 5

Fracture parameters calculated using analytical models

Parameter	KGD	PKN
Fracture length	119.5 m	332.1 m
Fracture width	2.41 mm	7.78 mm

5. 2. Construction of a 3D geological model of the deposit

A geological model of the deposit was constructed, which includes geophysical research data, petrophysical interpretation based on logging curves and a description of the available core. The boundaries of the reservoirs, the thickness of the productive layer, and the facies composition were determined. The geological model was reduced to a grid geometry that is compatible with Kinetix and takes into account the thicknesses, the angle of the layers, and the heterogeneity of the reservoir. This allows us to determine the optimal spatial placement of perforation clusters and the integration of geological modeling with hydrodynamic and geomechanical. The porosity distribution and structural-tectonic framework of the static model are shown in Fig. 2. As indicated in the histogram of the porosity distribution, it varies within 1–7%.

Permeability modeling was performed by searching for the dependence on porosity, in the form of a power function of the following type

$$k = a * \varphi^{b}, \tag{8}$$

where k – permeability, mD;

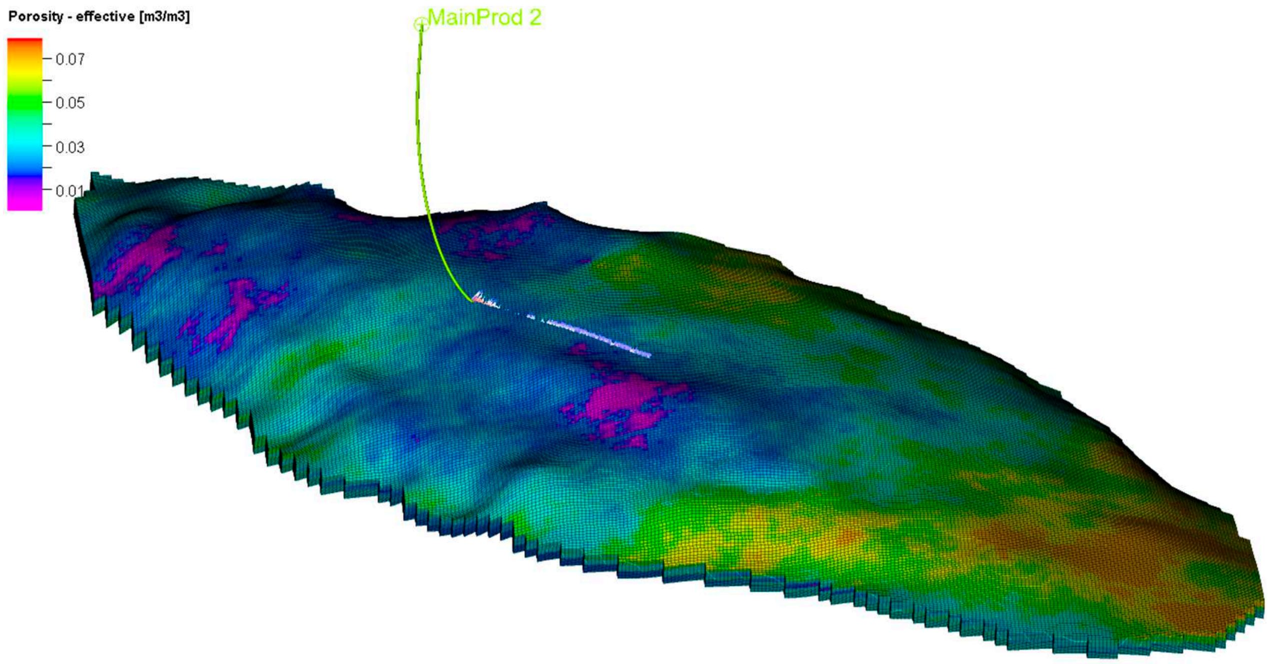
φ – effective porosity, %;

a, b – regression coefficients determined by approximating laboratory or logarithmic data.

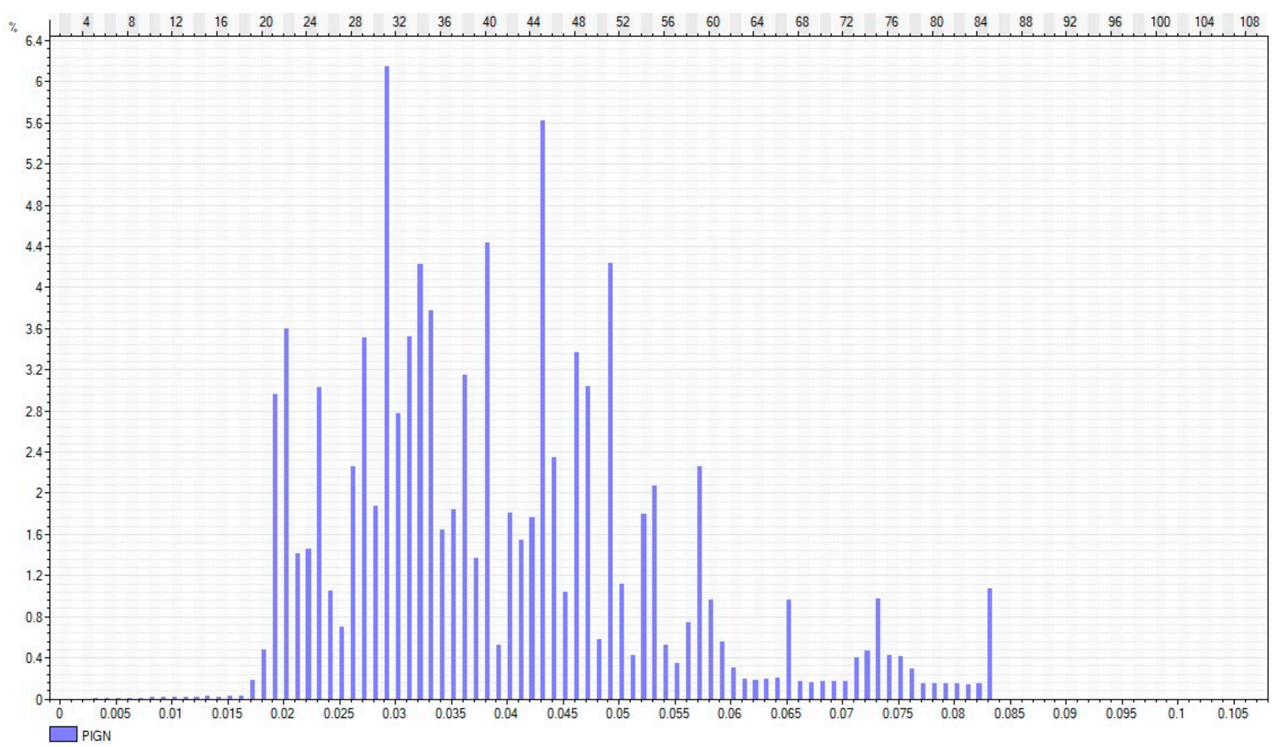
The dependence of permeability on porosity, which was used during the study, is shown in Fig. 3.

To simulate multi-stage hydraulic fracturing, a three-dimensional model of a horizontal well was built in Kinetix. The length of the horizontal part is 1600 m. The horizontal well model is shown in Fig. 4. The placement of stage clusters is carried out evenly with an interval of 200 m. Also, the geological model takes into account the heterogeneity of the distribution of formation properties, local changes in stresses, which will affect the geometry of the fractures of each stage.

A spherical quartz proppant with an average grain size of 20/40 was used for the fracturing simulation. A polymer-based aqueous gel with a viscosity that ensures uniform proppant distribution and minimizes losses during injection was used as the fracturing fluid.



a



b

Fig. 2. 3D Geological model: *a* — structural-tectonic framework; *b* — porosity distribution histogram

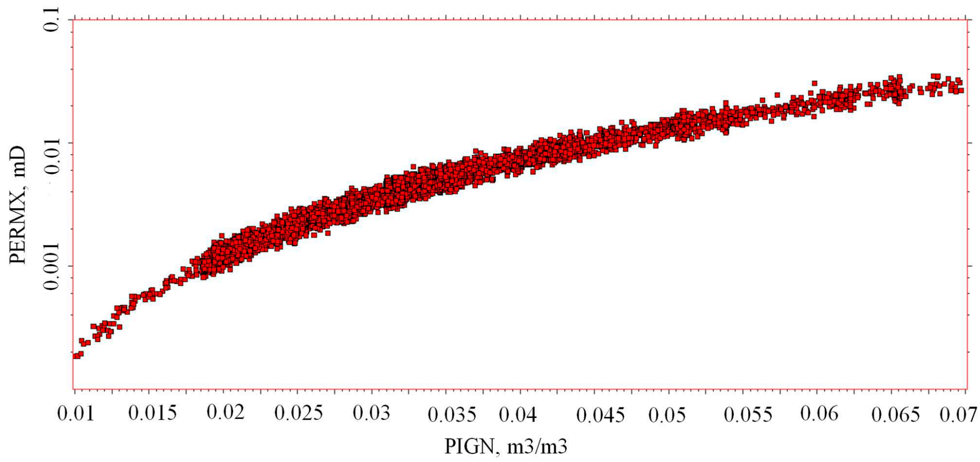


Fig. 3. Modeled dependence of permeability on porosity

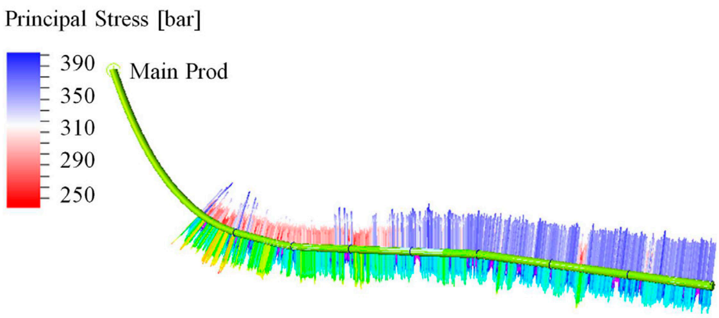


Fig. 4. Well model in Kinetix

Fig. 7 shows the geometry of the fractures as a discrete system. The given geometry can be used in a hydrodynamic simulator to predict the production from a given well.

The generalized geometric parameters of the fractures for the simulated fracturing stages are given in Table 6. The basic parameters for comparison with analytical models are length and average thickness. Height and average permeability are critical inputs for the hydrodynamic simulator in predicting production.

5. 3. Explicit fracture parameter calculation

As a result of the numerical simulation in Kinetix, an explicit representation of the fractures was generated for each of the 8 fracturing stages. The fracture lengths vary from 180 to 340 meters, depending on local geomechanical conditions and fracturing parameters. A histogram of the fracture lengths for each stage is shown in Fig. 5.

The height of the fractures varies from 30 to 42 meters, which indicates the influence of stratigraphic limitation, since it is equal to the average thickness of the productive horizon. The opening of the fractures reaches 7–11 mm. The dependence of the change in the thickness of the fractures for each stage on the injection time is shown in Fig. 6.

Table 6

Averaged fracture modeling results in Kinetix

Stage	Length (m)	Height (m)	Average opening (mm)	Medium permeability (mD*m)
1	339	32.2	8.23	774.49
2	298	30.9	8.88	906.80
3	276	31.3	9.06	982.03
4	249	32.1	9.42	1103.19
5	199	41.8	10.61	1067.41
6	192	40.5	10.50	1054.75
7	202	40.7	10.71	1106.76
8	249	37.1	8.03	1098.44

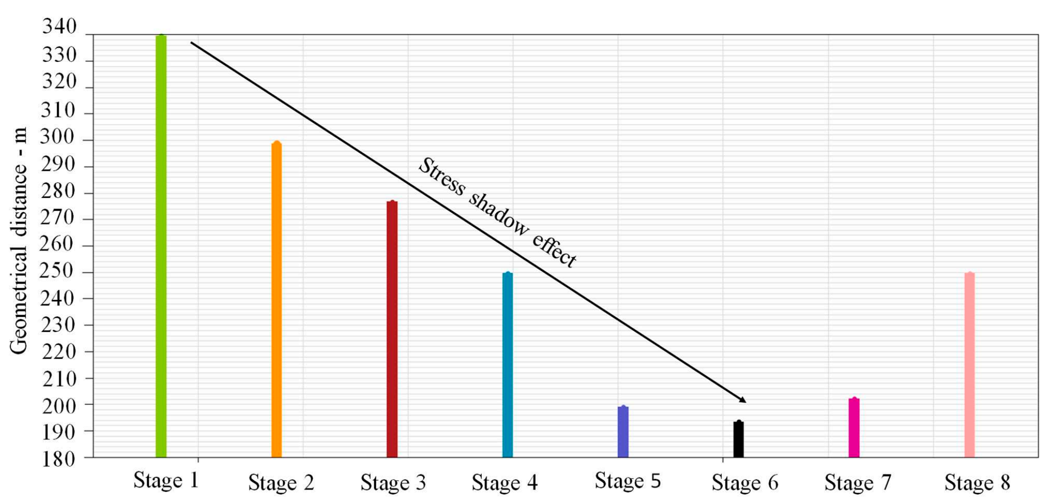


Fig. 5. Histogram of fracture lengths for each stage

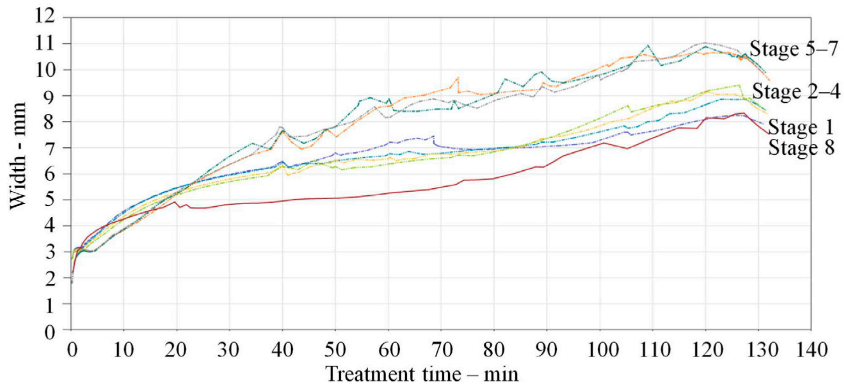


Fig. 6. Dependence of the change in fracture opening on injection time

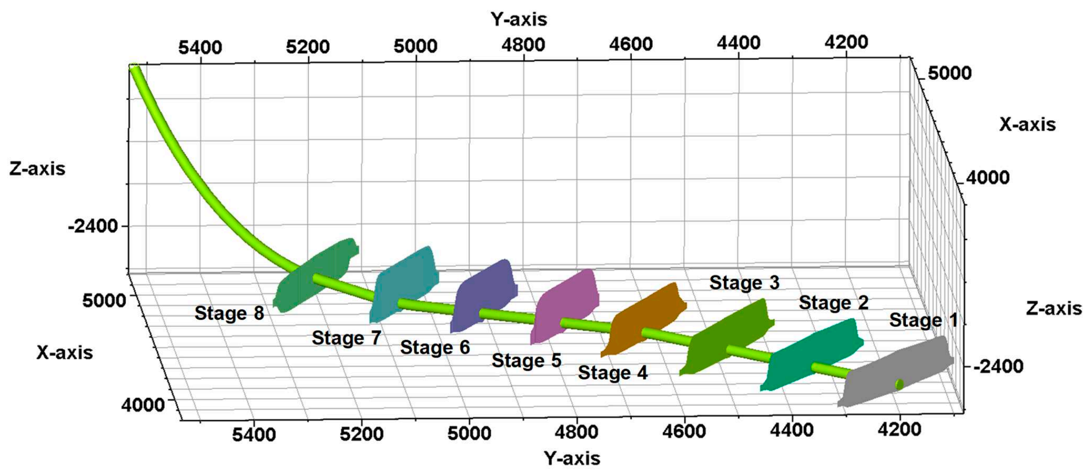


Fig. 7. 3D visualization of the shape, orientation, and arrangement of fractures in space

5. 4. Calculation of fracture coverage by proppant

The ratio of the total fracture area to the area covered by proppant is shown in Fig. 8 and Table 7.

Kinetix simulation results showed that the average percentage of the fracture area covered by proppant is 75%.

It should be noted that explicit fracture modeling also allows 2D visualization of proppant distribution along the fracture to assess asymmetry and gravitational shrinkage.

Table 7

Ratio of total fracture area to proppant area

Stage	Total fracture area, m^2	Area covered by proppant, m^2	%
1	10973	8637	78.7
2	9607	7440	77.4
3	8936	6905	77.2
4	8030	6149	76.5
5	8220	6300	76.6
6	7917	5898	74.5
7	8273	6251	75.5
8	7805	5955	76.2

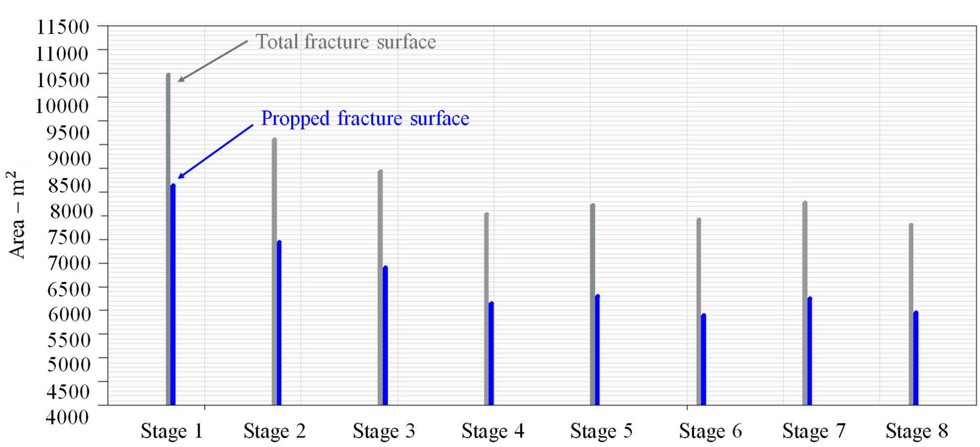


Fig. 8. Histogram of the ratio of the total fracture area to the area covered by the proppant

6. Discussion of results based on the parameterization of a fracture system using analytical and explicit methods

Our results from numerical and analytical modeling of the multi-stage fracturing fracture system indicate significant variability of the main parameters, such as length and width. Such variability is explained by different geomechanical properties of rocks and dependence on the technological conditions of fracturing. The main fracture parameters for the KGD and PKN models are given in Table 5. The fracture length in the KGD model is 119.5 m, while in PKN it is 332.1 m. The difference is due to the initial assumptions of the models. Namely, KGD assumes a square cross-section and fracture growth in height, typical of massive deposits, while PKN is focused on long thin fractures in small layer thicknesses. The corresponding fracture width for the KGD model is 2.41 mm, and in PKN it is 7.78 mm.

To build a geological 3D model of the deposit, geophysical survey data, petrophysical interpretation results, and core description are integrated. The model reproduces the spatial arrangement of the layers, the thickness of the reservoirs, and the reservoir properties of the rocks, distributed over the area (Fig. 2, 3). Using such a model allows us to assess the spatial asymmetry of the fractures, their orientation relative to the minimum horizontal stress, and integrate the results into a hydrodynamic simulator for production prediction.

The fractures of the first two stages of the stimulation demonstrate symmetrical growth relative to the perforation clusters, with a clearly defined direction relative to the minimum horizontal stress. Starting from the third stage, a shadow effect is observed, which leads to a decrease in the length and distortion of the fracture geometry, as indicated in Fig. 5 and Table 6. Stages number 6 and 7 are located at the end of the horizontal shaft, i.e., outside the zone of active influence from neighboring fractures, so their lengths are greater compared to the fractures of stages 5 and 6, respectively. The result of explicit modeling of multi-stage fracturing fractures allows us to visualize the 3D shape of the fractures of each stage, to assess their asymmetry, angle relative to the minimum horizontal stress, proppant distribution along the fracture and the resulting permeability, which will also change.

fracture parameterization during explicit modeling allows us to assess the efficiency of the formation of a system of fractures within different perforation clusters. It is also possible to perform sensitivity analysis for the influence of uncertain geomechanical parameters or to optimize the design of the hydraulic fracturing. The resulting 3D geometry of the fractures can be used to estimate spatial asymmetry, orientation relative to the minimum horizontal stress, and the corresponding permeability. Representing the fractures as a discrete system, as in Fig. 7, makes it possible to integrate the results of explicit modeling into a hydrodynamic simulator for further production prediction. The results obtained using explicit 3D modeling of fracture parameters with analytical models showed significant differences in geometry predictions. However, unlike analytical methods, the explicit method allowed us to reproduce the full 3D geometry, taking into account the interaction between stages. In particular, the simulated stages 3–6 are smaller due to the shadow effect of other stages.

The area of proppant coverage is also a key factor in calculating the effective permeability of a fracture, which in turn directly affects well productivity. The analysis of these indicators allows us not only to assess the quality of the performed hydraulic fracturing but also optimize the volumes of proppant for future stimulations.

Comparing the total area of the fractures with the area actually filled with proppant, as presented in Fig. 8 and Table 7, allows us to assess the uniformity of the proppant distribution and identify areas of potentially reduced permeability. This allows us to detect asymmetry and gravitational shrinkage, which will provide a deeper understanding of the actual functioning of the fractures and creates a basis for optimizing the volumes and modes of proppant supply. Also, 2D visualization of the proppant distribution along the fractures makes it possible to integrate the variable permeability over the area in a hydrodynamic simulator.

The consistency of the obtained values of the fracture parameters with the results of similar works [17, 18] confirms the correctness of the proposed method. In particular, in [17] the authors indicate a change in the half-length of fractures after fracturing in sealed reservoirs in the range from 50 to 150 meters, depending on the rheology of the proppant. Similarly, the results on the influence of the viscosity of the fracturing fluid on the fracture width, namely an increase to 7–8 mm, when using high-viscosity fluids and a narrowing to 2–4 mm with low-viscosity ones. This indicates the physical validity of the model and the reliability of numerical calculations.

An important feature of the proposed approach is the assessment of the area covered by the proppant. This parameter is not taken into account in many methods of fracturing modeling. In the calculations performed, this parameter is calculated as the product of the area of the fracture in which the proppant remained after settling, and the fraction of its filling. This allows us to correctly take into account the permeability of the fracture, the total stimulated volume during the prediction, because not the entire fracture will be conductive. That is, not the entire area of the fracture actually participates in fluid filtration. The significance of this criterion was confirmed by empirical data in previous studies [19, 20]. The authors of [19] showed that when using a fine proppant 70/140, the effective area covered by the proppant can reach values of 80%, while when using a larger proppant 40/70, this indicator decreases to 50% due to the overall decrease in fracture permeability. In addition, in [20] it is shown that only 70% of the created fractures provide the main production. The above is consistent with the results of explicit numerical modeling of the uneven distribution of proppant (Table 7, Fig. 8) and interference between stages. The influence of the shadow effect is given in Table 6, where the fracture parameters change from stage to stage.

The proposed approach complements existing models for predicting fracture parameters and allows us to take into account geomechanical data and heterogeneity of reservoirs in terms of area. In addition, the use of geomechanical parameter templates allows filling gaps in fragmentary input data. In particular, in [21] a comparison of hydraulic fracturing modeling methods was carried out, namely, the compaction of the hydrodynamic model grid dimension and the well-reservoir pseudoconnection method. However, the authors use averaged permeability parameters. This study of explicit fracture parameterization and calculation of the area covered by proppant can be used for further development of [2]. This will allow the use of additional parameters in the model and will increase the accuracy of the calculation of permeability and the influence of proppant distribution in fractures on well flow rates. It should be noted that the integration of these parameters into the hydrodynamic simulator is a challenge for future research. One solution may be the use of unstructured grids, where the fracture is represented explicitly by cells with increased filtration properties. The calculation of such models requires large computational resources and additional licensed software.

The practical significance of the results is the possibility of their application for assessing the quality of the performed hydraulic fracturing, optimizing the injection design, selecting perforation clusters, and adapting the proppant volumes taking into account its actual distribution in the fractures. It is important that the geometric and filtration parameters obtained from the model can be exported to formats compatible with hydrodynamic simulators.

Despite the consistency of our results with literature sources, explicit modeling of fractures has a number of limitations; specifically, limited analysis of the shadow effect and changes in the stress field during the formation of the fracture system. Although the model reflects the uneven distribution of the proppant and interfracture interaction, it is not yet possible to quantitatively assess it. Also, the viscosity of the fluid and the process of rheological degradation cannot be calibrated without additional laboratory studies. The physicality of the calculations is ensured by the ranges of input data taken from the templates. However, there is still a need to conduct full-fledged geomechanical studies. To eliminate or reduce the impact of these shortcomings, it is necessary to perform a sensitivity analysis of the input parameters and integrate the results with a full-fledged hydrodynamic model.

7. Conclusions

1. Based on the results of our performed calculations of the geometric and hydrodynamic parameters of fractures, the key limitations in the analytical models KGD and PKN have been identified. In particular, the inability to take into account the heterogeneity of geomechanical properties, natural fracturing, the shadow stage effect and the real distribution of proppant. This allows for a well-founded choice of the explicit modeling method as more physical and adaptive. In addition, the advantage of this method is explained by the possibility of integration with hydrodynamic simulators.

2. To enable explicit modeling of fractures and integration of geomechanical and reservoir properties of rocks, a 3D geological model of the deposit was built. The model is based on geophysical research data, petrophysical interpretation and core description, which allowed us to reproduce the thickness and length of the layers and variations in the mechanical properties of rocks. The use of such a model provides the basis for integrating the results of explicit modeling of fractures in a hydrodynamic simulator for further production forecasting.

3. An analytical and three-dimensional numerical model has been implemented. The main parameters of the fractures were determined for further forecasting of production and determining the productivity of the well. The result of numerical modeling in the Kinetix environment is the spatial geometry of the fractures, each stage of hydraulic fracturing, which is represented in the form of a discrete system of fractures. The obtained length of the fractures is from 180 to 350 meters, and the height varies within 40 meters, depending on the geomechanical properties of the rocks, the effects of interstage interaction and the location of the stages relative to the effective thickness of the horizon. During the modeling, a decrease in the length of the fractures is observed due to the accumulation of stresses in the zone of previous fractures, while for the stages located closer to the wellbore, a partial increase in the length was noted. This can be explained by the stages going beyond the stress interference zone or more favorable geological conditions. Taking into account the heterogeneity of the reservoir properties and the use of geomechanical templates have made it possible to reflect the change in the length and width of the fractures in space. Special feature of our results is the non-uniform change in the width of the fractures, which cannot be taken into account by analytical methods. This change is explained by the spatial and zonal change in Young's modulus and the direction of the minimum horizontal stress.

4. When determining the proppant coverage and its spatial distribution along the fractures, it was found that the calculated area of the fractures effectively filled with proppant is about 70%, which indicates a sufficient level of permeability necessary to ensure the productivity of the well. Assessment of the interaction between the stages showed the influence of the shadow effect from neighboring stages, namely, a decrease in the length of new fractures and a non-uniform distribution of the proppant. This effect cannot be reproduced by analytical models and is due to the non-uniformity of geomechanical properties.

Conflicts of interest

The authors declare that they have no conflicts of interest in relation to the current study, including financial, personal, authorship, or any other, that could affect the study, as well as the results reported in this paper.

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Data availability

The data will be provided upon reasonable request.

Use of artificial intelligence

The authors confirm that they did not use artificial intelligence technologies when creating the current work.

Authors' contributions

Oleh Lukin: Methodology, Formal analysis, Investigation, Resources, Data curation, Writing – original draft, Visualization; **Oleksandr Kondrat**: Conceptualization, Validation, Writing – review and editing, Supervision.

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