Modeling and Monitoring the Development of an Oil Field under Conditions of Mass Hydraulic Fracturing

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Abstract

In order to ensure the most complete recovery of hydrocarbons and to minimize costs in the production process, it is necessary to control the development of an oil field, even during production, through various geological and technological measures. In terms of the volume of additional oil extracted through the implementation of geological and technological measures, hydraulic fracturing (HF) operations occupy the top positions.

This paper describes a modified method for accounting for hydraulic fractures in a geological and technological model of a hydrocarbon field. The method makes it possible to perform all calculations related to the modeling of fractures in the pre-processing phase and to use its results as input data for the hydrodynamic simulator. An example of the calculation on a real development object is given. The analysis of the results showed the correctness of this method. The geological and hydrodynamic model provided a satisfactory reproduction of the development history for the oil field under study. The predicted flow rates and bottomhole pressures of the wells were close to the actual values. The error in annual oil and fluid rates is no greater than 3 %. The results of the calculations can serve as indirect confirmation of the hypothesis of spontaneous growth of hydraulic fracturing cracks in injection wells. In fact, by increasing the half-length of the hydraulic fractures in the injection wells in the model to 250 m, the discrepancy between the calculated and actual bottomhole pressures was reduced to fractions of a percent. The half-length of the fracture was 70 - 140 m and the half-opening was 1.2 - 2.5 mm. The average permeability of the proppant package in the crack is 220 d. The calculated skin factor for the design wells according to proposed model was −4.58.

Keywords: Hydraulic fracturing (HF), Reservoir simulation, Hydrodynamic simulator, Geological and technological modeling, Bottomehole pressure

Introduction

A significant portion of the world's oil reserves are located in fields that are difficult to develop because of their complex geological structure. Many of them are characterized by low permeability and porosity, a high degree of compartmentalization of the strata [1-3]. Economically viable development of such fields is not possible without the use of modern methods to increase oil recovery and intensify production.

For effective exploitation of deposits, a detailed analysis of the current stage of development, geological and technical measures in the field is necessary. If the field is at the initial stage, it is important to properly assess the amount of recoverable reserves, the potential for using various methods of production intensification and enhanced oil recovery [4-6]. This assessment helps to rationally plan the development of the field. The main tool in this case is the hydrodynamic model, which takes into account all available information as much as possible.

Worldwide practice has demonstrated the high efficiency of hydraulic fracturing (HF) in increasing both reserve development rates and ultimate oil recovery from formations with low permeability [7-9]. Many fields are being developed with the widespread use of this technology, and often hydraulic fracturing operations span the entire inventory of operating wells. In this case, hydraulic fracturing should be considered not only as a process that results in a change in the flow rate of a single well, but also as an element of the development system; a technology that can change the nature of flow in the reservoir.

Calculation methods in fracture models can be conditionally divided into direct and indirect [10-12]. In direct modeling of hydraulic fractures, the design grid is ground near boreholes and fractures to replicate the exact geometry of the fracture. This allows the nature of the inflow to be described in detail.

However, this method has a number of significant disadvantages. The introduction of additional computational cells that differ in size by several orders of magnitude leads to significant computational difficulties. The simplest way to account for hydraulic fractures indirectly is usually associated with the specification of a negative skin factor for treated wells, which increases their design capacity. However, such a technique can distort the picture of flow in the formation, as flow remains radial to the wells, which can lead to erroneous results.

This paper describes 1 of the methods for accounting for hydraulic fractures in the geological and hydrodynamic models of the field, and the experience of applying it to a real development target.

Materials and methods

An oil field located in Western Siberia is considered. Currently, this field is poorly explored. Only a small area in the northwest part of the field has been drilled, and the development history is only 2 years old. The operating experience of the adjacent field is only partially applicable, as the field area under study is located in the regional part, which is characterized by its geological structure.

In general, the field formations are characterized by low reservoir properties (permeability 5 - 7 md, porosity 16 - 19 %) and a high degree of compartmentalization. The main characteristics of the field formations are presented in **Table 1**. Currently, production is only from the AS10 group formations, and the AS12 group formations are to be included in the development.

Table 1 Geological and physical data of the formations and reservoir fluids of the studied field.

Parameter	Formation	
	AS10	**AS12**
Effective oil-saturated thickness, m, average/(min-max)	4/(2 - 22)	2,7/(2 - 26)
Formation porosity, fraction of units, average/(min-max)	0,185/(0,14 - 0,21)	0,158/(0,15 - 0,23)
Average permeability (by core), 10^{-3} μm^2	2,1	1,8
Dismemberment	9,3	49
Initial reservoir pressure, MPa	25,7	26,8
Oil viscosity in reservoir conditions, mPa·s	1,77	1,38
Density of oil in reservoir conditions, t/m^3	0,834	0,818
GOR, m^3/t	53	57
Viscosity of water in reservoir conditions, mPa·s	0,38	

When reservoir productivity is low, well operation is impractical without the use of production intensification methods. At high compartmentalization and low net pay thickness, the use of horizontal wells is economically and technologically ineffective [13-15].

Hydraulic fracturing is used as the main method to stimulate hydrocarbon wells in the adjacent field. The same technology has been actively introduced at the studied field. Almost all hydraulic fracturing operations were found to be successful and resulted in multiple increases in production. The average initial flow rate of the wells for fluid was 96 t/day, the initial water cut of production was less than 10 %. Due to the high efficiency of hydraulic fracturing operations, they are performed on all wells prior to their start-up.

In order to evaluate the current state and determine the further development strategy, a hydrodynamic model was created. It was necessary to take into account as much as possible the technological operation of the reservoir and especially the large-scale introduction of hydraulic fracturing. Hydraulic fracturing in this case should be considered not only as a method of production intensification, but also as an element of the development system that changes the geometry of the flow in the reservoir.

In this paper, a technique is proposed to perform separately all additional calculations related to fracture modelling and to use their results as input data for hydrodynamic calculations. This approach seems to be quite universal, as it allows the use of different software systems for hydrodynamic modelling.

Computational-analytical approach

In this paper, a computational-analytic approach is used, which consists in conjugating the finite-computational solution for the reservoir and the analytic solution near the fracture. In this case, a special formula for the inflow to the wellbore is introduced and the flow in the fracture is assumed to be nearly 1-dimensional [16]. The inflow formula is derived from the analytical solution of the corresponding problem, considering a symmetric elliptical fracture with finite conductivity and the fluid is assumed to be homogeneous and incompressible. The inflow formula is as follows [16]:

$$Q = \frac{2\pi k \Delta z}{\mu} \frac{\sum_{i=1}^{4} c_i(p_o - p_w)}{\sum_{i=1}^{4} c_i P(Z_i) - 2\pi} \tag{1}$$

where: $c_{1,2} = a_{1,3}\left(1 + \frac{2wk_f}{\Delta yk}\right)$, $c_{2,4} = a_{2,4}$, $a_{1,3} = \frac{\Delta y}{\Delta x_{1,3}}$, $a_{2,4} = \frac{\Delta y}{\Delta x_{2,4}}$;   (2)

$$P(Z_i) = R_e\left((1-\lambda)\ln\frac{2Z_i}{f} + \lambda\ln\left[\frac{Z_i}{f} + \sqrt{\frac{Z_i^2}{f^2} - 1}\right] + (1-\lambda)\sum_{m=1}^{\infty}\lambda^m\ln\left[1 + q^m\left(\frac{Z_i}{f} - \sqrt{\frac{Z_i^2}{f^2} - 1}\right)^2\right]\right) \tag{3}$$

$$q = \sqrt{\frac{1-w}{1+w}} \; ; \quad \lambda = \frac{k_f - k}{k_f + k} \; . \tag{4}$$

Here $P(Z_i)$ – Pressure; Z_i - the complex coordinate of the i-th node in the coordinate system associated with the fracture; f - fracture half-length, 2w - fracture width, k_f - fracture permeability; Δx_i and Δy_i - distance to the center of the adjacent block of the computational grid; p_o - pressure in the block in which the well is located; p_w - bottomhole pressure; k - formation permeability; Δz - block thickness; μ - the viscosity of the fluid. If the fracture is directed along the X-axis of the computational grid, then

$$Z_1 = -\Delta x_1, \quad Z_2 = i\Delta y_2, \quad Z_3 = \Delta x_3, \quad Z_4 = -i\Delta y_4.$$

In the case of a multiphase flow, the inflow formula is introduced for the total flow of all phases, taking into account their total mobility, and the expression (1) is transformed into the form

$$Q = 2\pi k \Delta z \sum_{j=1}^{3} \frac{f_j}{\mu_j} \frac{\sum_{i=1}^{4} c_i(p_o - p_w)}{\sum_{i=1}^{4} c_i P(Z_i) - 2\pi} \tag{5}$$

where: $c_{1,3} = a_{1,3}\left(1 + \frac{2wk_f}{\Delta yk}\left(\sum_{j=1}^{3}\frac{k_{fj}}{\mu_j}\right)\left(\sum_{j=1}^{3}\frac{k_j}{\mu_j}\right)^{-1}\right)$, $c_{2,4} = a_{2,4}$.   (6)

Here k_j and k_{fj} are the relative phase permeability for the formation and the fracture, respectively, the subscript j = o refers to oil and j = w to water.

Depending on the characteristics of the simulator used for reservoir modelling, various modifications of the computational analytical method for calculating fractures in hydraulic fracturing have been developed [17-20].

The Peaceman method is commonly used to account for hydrocarbon wells in flow models [21]. It consists in combining the analytical solution of the problem of radial inflow of an incompressible fluid to a point drain with the numerical solution of the problem of flow in the reservoir. This is done using the inflow formula

$$Q = \frac{2\pi k \Delta z}{\mu} \frac{p_o - p_w}{\ln r_o/r_w - s} \tag{7}$$

Where p_o is the pressure in the grid block where the well is located; r_w is the borehole radius; r_o is the effective radius of the block, which is the distance from its centre to the conditional contour within the block where the pressure is equal to p_o.

The value of r_o is determined by the computational grid geometry:

$$r_o = 0{,}28\sqrt{\Delta x^2 + \Delta y^2} \tag{8}$$

Here Δx and Δy are the distances between the nodes of the computational grid along the corresponding axes.

Additional flow resistances in the borehole and in the near borehole zone are taken into account with the skin factors. For geological and engineering measures that improve the properties of the borehole bottom and reduce its flow resistance, the skin factor can become negative [22-24].

For an anisotropic reservoir, the formulas (7) and (8) have the form

$$Q = \frac{2\pi\sqrt{k_x k_y}\,\Delta z}{\mu}\,\frac{p_0 - p_w}{\ln r_0/r_w - s} \qquad (9)$$

$$r_0 = 0.8\,\frac{\sqrt{\sqrt{k_y/k_x}\,(\Delta x)^2 + \sqrt{k_x/k_y}\,(\Delta y)^2}}{\sqrt[4]{k_y/k_x} + \sqrt[4]{k_x/k_y}} \qquad (10)$$

To simulate the inflow to the hydraulic fracture, one can compare the dependencies (7) or (9) with formula (1) and calculate the value of the skin factors at which the calculated flow rates will agree. However, if the fracture (crack) length is comparable to or exceeds the grid block size for deep penetrating hydraulic fracturing, setting a special inflow formula of the form (1) or (5) will not allow the model to represent the flow pattern near the crack.

The effective conductivity of the grid blocks through which the crack passes is characterized by anisotropy, which is associated with increased crack throughput. This effect is quite easy to take into account in the model if the direction of 1 of the axes of the computational grid coincides with the direction of crack propagation. In this case, it is possible to adjust the reservoir anisotropy with respect to permeability. While for multiphase flow and in terms of phase permeability, the anisotropy can be adjusted within the corresponding grid blocks:

$$k_x^* = k_x\left(1 + \frac{2wk_f}{\Delta y k_x}\right); \quad k_y^* = k_y\,; \quad k_z^* = k_z \qquad (11)$$

Here k_x^* is the effective permeability in direction i, (i = x, y and z.).

Effective phase permeability is introduced in the same way and is thus shown to be anisotropic. By equating the total interblock conductivity in phase j in the direction of crack propagation, which in this case coincides with the direction of the X-axis, we obtain

$$k_x k_{xj}^* \Delta y = kk_j \Delta y + k_f k_{fj} 2w \qquad (12)$$

where k_{xj}^* is the desired relative phase permeability for the jth phase in the X direction.

From (12), considering (11), we obtain an expression for the effective relative phase permeability:

$$k_{xj}^* = \frac{k_j}{1 + \frac{2wk_f}{k\Delta y}} + \frac{2wk_f}{k\Delta y}\,\frac{k_{fj}}{1 + \frac{2wk_f}{k\Delta y}}\,; \quad k_{yj}^* = k_j\,; \quad k_{zj}^* = k_j \qquad (13)$$

Due to the smallness of the crack volume compared to the volume of the grid block, it can be assumed that the effective saturation of the block traversed by the crack is not different from the reservoir saturation calculated for this block.

As is well known, the capillary effects in the crack are insignificant, so that the dependence of the phase permeability on the corresponding saturation can be assumed to be linear. Moreover, it can be assumed that hydraulic fractures in injection wells are immediately filled with water and are conductive only for this phase. Thus, the relative phase permeability of the fracture for the production and injection wells can be set in the form

$$k_{fw} = \begin{cases} (s_w - s_{wc})/(1 - s_{wc}), & \text{for production well} \\ 1, \text{for injection well} \end{cases}$$

$$k_{fo} = \begin{cases} (s_o - s_{oc})/(1 - s_{oc}), & \text{for production well} \\ 0, \text{for injection well} \end{cases} \qquad (14)$$

Here, S_o and S_w are the saturation of the oil and water phases, respectively; S_{oc} and S_{wc} - residual oil- and water saturation. These dependencies are taken into account in the calculation of anisotropic phase permeability (13).

The skin factor of a well intersected by a hydraulic fracture is obtained after substituting expressions (1), (10) and (11) into (9) in the form.

$$s = \ln \frac{r_o}{r_w} - \left(\frac{\frac{\sum_{i=1}^{4} c_i P(Z_i) - 2\pi}{k} \sum_{i=1}^{4} c_i}{\sqrt{1 + \frac{2wk_f}{\Delta y k}}} \right) \tag{15}$$

Thus, a hydraulic fracture simulation can be performed by introducing formation anisotropy in the absolute and phase permeability for the grid blocks intersected by fractures and setting a specially calculated skin factor in the wells. This approach allows, on the one hand, not to grind the computational grid near the well, and on the other hand - to reliably describe the behaviour of the flows in the cells containing the fracture.

Calculation example

The proposed method was used to model the hydrocarbon field under study. In the development of this field, it is expected that hydraulic fracturing will be carried out in all wells. In the hydrodynamic model, hydraulic fracturing in the drilled wells was simulated with real fracture parameters, and values averaged over all operations were established for the design wells. The half-length of the fracture was 70 - 140 m and the half-opening was 1.2 - 2.5 mm. The average permeability of the proppant package in the crack is 220 d.

According to the results of studies and field data on the adjacent hydrocarbon field, hydraulic fractures mainly propagate in the north-northwest direction [25]. Along this direction, the X-axis of the computational grid of the model was aligned, which made it possible to consider cracks oriented along this axis. The size of the cells laterally in the grid model is 100 m. With a fracture half-length of 100 - 150 m, it can be assumed to pass through 3 cells of the computational grid, with a well in the middle. Considering the accepted average parameters of fracture and reservoir permeability, the anisotropy of permeability in these cells was according to (11)

$$k_x^*/k_y^* = \left(1 + \frac{2wk_f}{\Delta y k_x} \right) = 2$$

As can be seen from the result of applying the proposed fracturing model, the horizontal permeability was improved to 2 times the vertical permeability, resulting in a significant improvement in the flow rate.

Phase permeability was determined for both producing and injecting wells. The initial and effective relative phase permeability (13) for the cells through which the cracks pass is shown in **Figure 1**. The calculated skin factor for the design wells according to (15) was −4.58.

Applying the proposed fracturing model, **Figure 1** clearly shows the increase in the relative phase permeability for the oil and the water compared to their initial values. This is naturally reflected the enhancement in the value of the skin factor, which has a negative value of −4.58. This figure is a very clear proof of the success of stimulating the formation for a higher production.

After preparation of the computational grid, information on the history of field development was loaded into the hydrodynamic model, taking into account also the wells of the neighboring license areas of the adjacent field. Correctness of consideration of fractures in hydraulic fracturing was checked at the stage of model fitting. Comparison of calculated and actual development indicators was carried out in 1-month increments. The main purpose of the fitting was to reproduce oil and fluid production for each well using the same calculated and actual bottomhole pressures. The error in annual oil and fluid production is no greater than 3 %. Satisfactory results were obtained for individual wells (**Figure 2**).
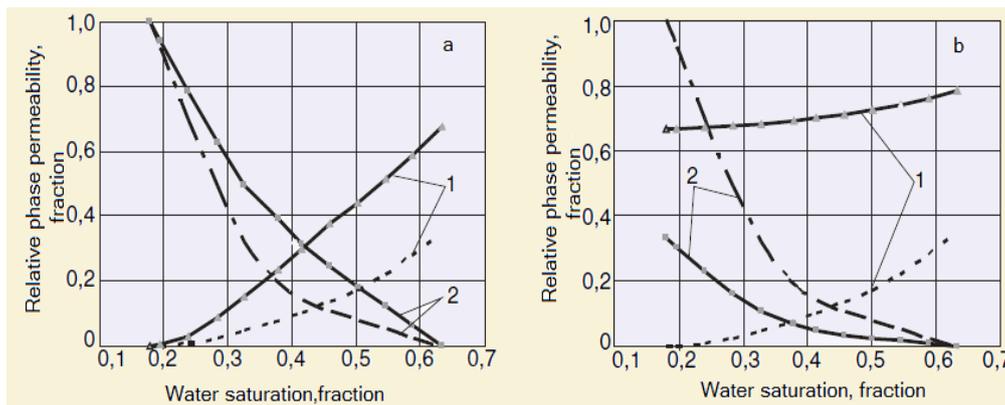
Figure 1 Initial (dashed lines) and averaged (solid lines) curves of the relative phase permeability of water (1) and oil (2): A - producing wells; b - injection wells.
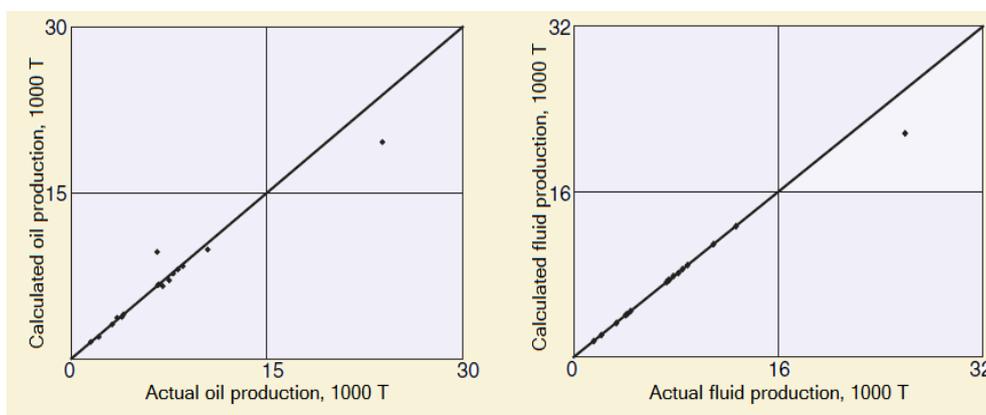
Figure 2 Reproduction of the development history for the wells of the investigated license area.

This figure shows that most of the calculated and actual values lie on the same graphical line, indicating the high accuracy of the proposed model for calculating oil and fluid flow rates. As mentioned earlier, the error is not more than 3 %.

In particular, the dynamics of the water cut in 1 of the production wells near the border could be correctly reproduced from the injection well of the adjacent license area. As can be seen in **Figure 3**, by considering hydraulic fractures in the model, it was possible to simulate the hydrodynamic connection of these 2 wells, which are located at a considerable distance.
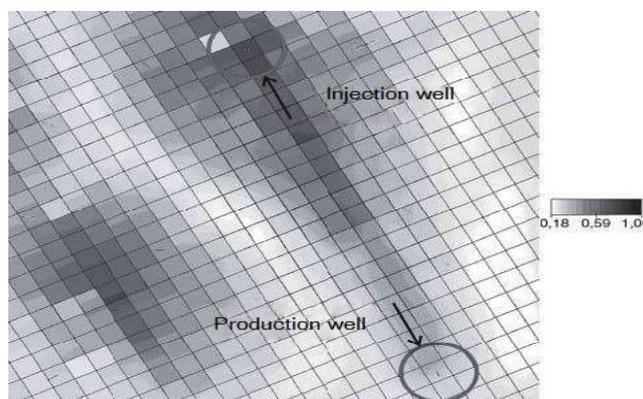
Figure 3 Water saturation distribution of the investigated field on 01.01.2020 Fragment of the hydrodynamic model.

The calculations show that the method of considering cracks in hydraulic fracturing gives good results and can adequately model the development process. This was also confirmed during the development monitoring. The constructed model was supplemented with data from newly drilled wells. After production wells were drilled, it was found that the predicted indicators were close to the actual ones (**Figure 4**).
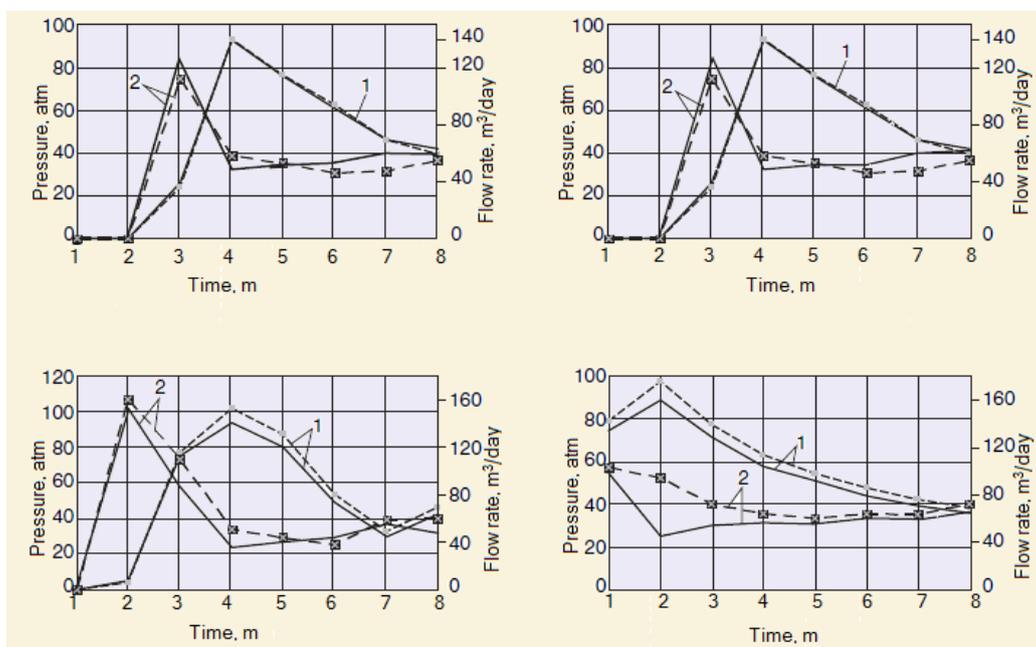

Figure 4 Comparison of calculated (solid lines) and actual (dashed lines) indicators of four different production wells: 1 - oil flow rate m^3/day; 2 - bottomhole pressure, atm.

As can be seen from **Figure 4**, the actual and calculated values are very close. This concerns both the flow rates and the wellbore pressure values for various newly drilled wells.

In 2020, implementation of the reservoir pressure maintenance system began. It turned out that the parameters of hydraulic fractures included in the model, calculated for production wells, could not properly simulate the process of water injection. The calculated bottomhole pressure was higher than the actual values. This can serve as an indirect confirmation of the hypothesis of spontaneous growth of hydraulic fractures in injection wells, which was established on the basis of the development experience of the adjacent field [26]. In fact, by increasing the half-length of the hydraulic fractures in the injection wells in the model to 250 m, the discrepancy between the calculated and actual bottomhole pressures was reduced to fractions of a percent. Considering that the injection was introduced relatively recently, the justification for such an intervention requires additional scrutiny.

The design of the field development system considered the change in drainage area of each well in the presence of extensive hydraulic fractures. Linear well layouts were used, with rows of production and injection wells arranged along the direction of fracture propagation. Since the affected zones of the wells extend along the hydraulic fractures, it was decided to bring the rows closer together by increasing the spacing between the wells in the row. After multivariate calculations, a grid of wells was chosen, which is schematically shown in **Figure 5**. The distance between wells in the row is 1000 m, between rows −300 m.
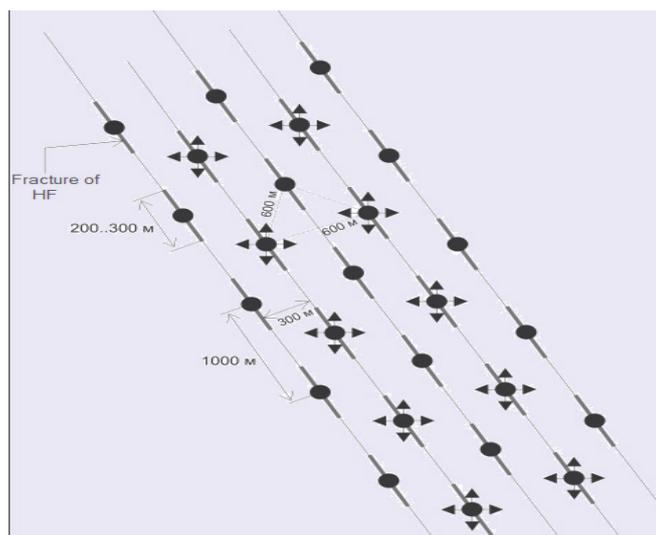
Figure 5 The placement scheme of wells according to the recommended option.

The geological and hydrodynamic model produced in the paper is not definitive. The geological structure of the field is constantly updated during the drilling of new wells. The gradual implementation of the development plan will demonstrate the effectiveness of the selected option. Improvement of hydraulic fracturing technology and introduction of other methods of production intensification require additional analysis of development status and adjustment of project indicators.

Conclusions

A method is proposed to account for hydraulic fractures in the hydrodynamic model of the field. This method makes it possible to perform separately all the additional calculations associated with the modeling of fractures and to use their results as input data for the hydrodynamic extension. This approach seems to be quite universal, as it allows the use of different software systems for hydrodynamic modeling. For development systems with multiple wells, implementation of the method does not require significant time costs associated with computational difficulties.

The results of applying the proposed approach to a real object are presented. In particular, the reproduction of flow rates and wellbore bottom pressures after hydraulic fracturing in producing wells was achieved. Moreover, the simulation of abnormal dynamics of water cut growth in 1 of the wells due to hydraulic fracturing was achieved and indirectly confirmed the possibility of spontaneous crack growth in injection wells.

The application of the proposed method made it possible to create an optimal development option from a technical and economic point of view, involving the large-scale use of hydraulic fracturing. By increasing the half-length of the hydraulic fractures in the injection wells in the model to 250 m, the discrepancy between the calculated and actual bottomhole pressures was reduced to fractions of a percent. The production figures from the newly drilled wells were close to the forecast values. The half-length of the fracture was 70 - 140 m and the half-opening was 1.2 - 2.5 mm. The average permeability of the proppant package in the crack is 220 d. The calculated skin factor for the design wells according to proposed model was −4.58.

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