Improving the geological and hydrodynamic model of a carbonate oil object by taking into account the permeability anisotropy parameter

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Significant share of the developed oil assets related to carbonate complex-built objects has formidably increased in Russia, including the Perm Region. Reliable knowledge of the parameters for the cavern-pore type of the reservoir allows clarifying the existing geological and hydrodynamic models (GHM), selecting a rational development system, regulating the development processes and providing optimal geological and technical measures for this formation. In the construction and adaptation of GHM for oil fields, especially those related to complex-built carbonate reservoirs, knowledge of both horizontal and vertical permeability (anisotropy parameter) is important. When creating GHM of carbonate objects in Perm Region deposits, vertical permeability is often taken to be zero, although this is far from being the case. Determining the vertical permeability (anisotropy parameter), its dynamics when changing the formation and bottomhole pressures and using it in GHM is an urgent task that will improve the quality and reliability of using digital models to calculate and predict the oil production process.

Article describes the methodology for determining permeability anisotropy according to the interpretation of hydrodynamic investigations of wells. Proposed methodology for determining the anisotropy parameter processed the results of more than 200 studies conducted on production and injection wells of the Famennian deposit at the Gagarinsskoeye field. For each lithological-facies zone, dependence of the permeability anisotropy index on the bottomhole pressure is constructed. To predict and evaluate the effectiveness of the applied geological and technical measures and technological development indicators, author modified the geological and hydrodynamic model taking into account the obtained dependencies on the change in the anisotropy parameter.

Using a modified hydrodynamic model, it was possible to significantly improve the adaptation of both production and injection wells. Thus, the quality and reliability of the digital model of the Famennian deposit at the Gagarinskoye field for calculating and predicting the oil production process has improved.

Key words: vertical permeability; horizontal permeability; permeability anisotropy parameter; complex-built carbonate deposit; modified geological and hydrodynamic model

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Introduction. In the Perm Region, the share of developed oil assets related to complex carbonate objects has significantly increased. Complex carbonate reservoirs are characterized by different types of cavernosity (pores, cracks, cavities), significant inhomogeneity, fluid flows between types of cavernosity, as well as the difference between lateral and vertical permeability, and these factors significantly affect the productivity of production wells and an overall oil recovery factor [1, 11, 14, 16]. Reliable knowledge on the parameters of the cavern-pore type of the reservoir allows clarifying the existing geological and hydrodynamic models (GHM), select a rational development system, adjust development processes and provide optimal geological and technical measures (GTM) for the given formation [5, 10, 13].

In the construction and adaptation of oil fields' GHM, especially those related to complex carbonate reservoirs, knowledge of both horizontal and vertical permeability (anisotropy parameter) is important [10, 14]. When creating GHM of carbonate objects in the Perm Region's deposits, vertical permeability is often taken to be zero, although this is far from being the case (it is known that cavernosity can exist in the mudstone formation, although permeability is almost zero in laboratory study) [10]. Knowledge of vertical permeability under conditions of a complex carbonate reservoir is of particular importance with the active role of formation water. Oil production may be high for some period, but then it will decrease when a bottom water cone appears, which is often formed during irrational development of reserves and unreasonable technological regimes of production wells’ operation. Process of cones’ formation is much more intense in cavern reservoirs with vertical
cracks, since they extend far down into the underlying formations, forming paths for creating water cones [6, 15, 17]. Thus, determination of vertical permeability (anisotropy parameter) and its use in GHM is a relevant task that will improve the quality and reliability of digital models' application for calculating and predicting the oil production process [3, 4, 8, 18].

**Methods for determining the anisotropy parameter (vertical permeability).** Permeability anisotropy parameter in carbonate reservoirs can be determined by geophysical, field and hydrodynamic investigations (HDI) of wells and formations [7]. Examining of rock sample and geophysical study cannot provide accurate knowledge on the features of the formation in connection with the investigation peculiarities. The most developed methods for determining the parameter of permeability anisotropy are the methods of well interference testing and tracing of marked substances, however, they are quite time consuming and expensive. Method of tracing indicators can be reliably implemented at a later stage of field development with intensive fluid watering. Particular attention should be paid to the interpretation of data from hydrodynamic investigations of wells (PRC/LRC (level recovery curve)/PSC (pressure stabilization curve) as the most common method of monitoring field development, which allows solving a huge range of production and scientific problems [7, 12].

**Determination of permeability anisotropy parameter according to hydrodynamic investigations of wells.** In [9] authors described a method for determining vertical permeability and permeability anisotropy parameter. Essence of the technique is as follows: initial pressure recovery curve (PRC) is reconstructed in the coordinates $P_{bof}(t) - \lg(t)$. Final part of the PRC is considered – final section is distinguished and the slope $\beta$ is determined. PRC is also built in coordinates $P_{bof}(t) - 1/t^{0.5}$, on which the straight section is selected so that the time corresponding to its end is less than the time corresponding to the beginning of the straight section in coordinates $P_{bof}(t) - \lg(t)$, and the slope of the section $\sigma$ is determined. And further, if drilled (working) thickness $h_{dth}$ is known, values $\sigma$ and $\beta$ and the coordinates of the last point of the line constructed in the coordinates $P_{bof}(t) - 1/t^{0.5}$, following properties are sequentially determined: total formation thickness, vertical permeability $P_v$, vertical piezoconductivity, horizontal permeability $P_g$, and consequently the anisotropy parameter.

Relevance and value of these calculations is obvious, since, on the one hand, informational content of the well research by pressure recovery is enhanced, and on the other hand, it is possible to obtain very valuable information about the anisotropy of the formation without the cost of special investigations.

Using this technique, results of more than 200 investigations conducted on the production and injection wells in the Famennian deposit at the Gagarinskoye field were processed. Carbonate oil deposit in the Famennian deposits at the Gagarinskoye field is characterized by double cavernosity, and the geological model for the deposit formation with a successive change in the following lithological-facies sedimentation conditions can be considered typical: reef slope, lower and upper rear drags, bioherm core [7]. Deposits of the upper rear drags, related to the central interreef part of the formation are characterized by the largest capacitive space. Facies of the lower rear drag, bioherm core, and reef slope are confined to lower relief sections of the geological section. During sedimentation, a greater amount of micritic material was carried to them, which reduced their capacitive characteristics. On a number of deposits, rifogenic formations, which are usually characterized by low permeability and porosity properties, are also isolated into a separate lithological-facies zone. Complex structure of the reservoir, caused by sedimentation conditions, led to alternation in the section and on the reservoirs area of different capacities for each stratigraphic range [2, 7]. For each lithological-facies zone, dependence of the permeability anisotropy index on the bottomhole pressure was constructed (Fig.1). Obtained dependencies can be used to predict the permeability anisotropy parameter in each lithological-facies zone, which may affect the selection of the optimal technological mode of the well operation and the choice of geological and technical measures.
To predict and evaluate the effectiveness of the applied geological and technical measures and technological development indicators, author of the article modified the GHM taking into account the obtained dependencies for the change in the permeability anisotropy parameter. Modified GHM, compared with the base model, which does not take into account the anisotropy index, will allow reliable evaluation of the technological development indicators and well operation modes after the completion of GTM.

**Improving the geological and hydrodynamic model taking into account changes in the anisotropy index.** There are many ways to account for cavernosity in hydrodynamic models. The most laborious, but at the same time physical, is the creation of a double medium model. Obvious advantage of this GHM is taking into account the complex structure of the cavities during multiphase filtration of the formation fluids. However, the process of building the model and its use is associated with significant difficulties, such as the ambiguity of determining the parameters of the cavern medium and the model's overloading with a slowdown in the calculation speed as a result of the permeability and porosity properties' distribution between two cavities, as well as the interflows between them. Therefore, such models are rarely used. Another method of GHM is based on the use of seams with low porosity and high permeability, such as the area of wells. Non-adjacent junctions are also used, in which the fluid can be transferred almost instantly from one point in the formation to another. Indirect modeling of the filtration in the cavern-pore reservoir can be done using relative phase permeability curves (RPP). There are methods to account for changes in reservoir permeability depending on reservoir pressure dynamics. A similar method was chosen to take into account the cavern component of the cavity space of the Famennian deposit at the Gagarinskoye field. It gave satisfactory indicators with rational time costs for modifications. Modeling was performed in a hydrodynamic simulator “Tempest” ver. 8.3.1 by Roxar.

Preliminary vertical permeability was numerically adjusted according to the results of the interpretation of hydrodynamic investigations (HDI). Then, the process of modifying the hydrodynamic model took place by searching for permeability multipliers in several stages:

1. Converting the obtained dependence of the anisotropy index on the ratio of the current bottomhole pressure to the initial reservoir pressure into the dependence of the anisotropy index on the current reservoir pressure. Dependencies will be the same.

2. Dependence of permeability on reservoir pressure is constructed as a result of the hydrodynamic investigations' analysis, conducted under transient conditions. Permeability obtained in the investigations will be equal to the lateral permeability $K_x = K_y$.

3. With a sufficiently small pressure step (for example, 5 bar) from atmospheric to reservoir pressure (discreteness can be reduced above this threshold), permeability values along the lateral are obtained.

4. Value of horizontal permeability is substituted into the dependence of the anisotropy index on the current reservoir pressure. Result is the distribution of vertical permeability with regard to reservoir pressure.

It is assumed that at the initial formation pressure the permeabilities are not changed, and when the pressure changes in one direction or another, they increase or decrease. Since the distribution of

![Fig.1. Dependence of anisotropy index on bottomhole pressure for lithological-facies zones of the Famennian deposit at Gagarinskoye field](https://example.com/figure1.png)

1. Facies of bioherm core, $y = 34.719e^{0.175x}$, $R^2 = 0.5255$;
2. Facies of the upper rear drag, $y = 0.0758x^{0.072}$, $R^2 = 0.6562$;
3. Facies of the lower rear drag, $y = 28.606e^{-1.11x}$, $R^2 = 0.6$. 

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permeability in the area of each well can vary significantly, it is not the permeability values that are needed for use, but their multipliers (with $P_{fr} = P_{fr.in}$ the multiplier is equal to one). Process of modifying the hydrodynamic model by searching for permeability factors is shown in Fig.2.

Analyzing the obtained graphs, it can be concluded that with a significant decrease in formation pressure, the role of vertical filtration becomes significant. This procedure was performed for each lithological-facies zone of the development object under consideration. Thus, there are dependencies of lateral and vertical permeability changes for each zone. In contrast to the common method using the KVSP keyword, the use of the KVPX, KVPY, and KVPZ keywords allows for multidirectional distribution of changes in permeability with regard to pressure, which was done. Appearance of the modified geological and hydrodynamic model is presented on the example of a cube of altered regions (Fig.3).

When working with the modified model, it was possible to improve adaptation both for production (Fig.4) and injection wells (Fig.5).

Thus, the calculations using the modified hydrodynamic model in well 429 allowed recreating the dynamics of the bottomhole pressure, adjusting the formation pressure trend and significantly improve the convergence of the water cut parameter. In well 71, the necessary historical repression was achieved, and the entire volume of injected liquid flowed into the formation. This did not work on the original model and the bottomhole pressure was on the shelf for some periods of time (the auto-hydraulic fracturing effect was simulated).

Fig. 2. Dependence of permeability multipliers on formation pressure for facies of the upper rear drag
1 – ratio of multipliers $K_2/K_1$; 2 – $K_2$; 3 – $K_1$

Fig. 3. Appearance of the modified geological and hydrodynamic model of the Famennian deposit at the Gagarinskoye field
Fig. 4. Comparison of adaptation results for production well 429 on a modified and original model:
- $a$ – flow rates; $b$ – total production and water cut; $c$ – injection; $d$ – pressure

Fig. 5. Comparison of adaptation results for injection well 71 on a modified and original model:
- $a$ – flow rates; $b$ – total production and water cut; $c$ – injection; $d$ – pressure

See the legend in Fig. 4.

**Conclusion.** This article considers an urgent problem aimed at determining the permeability anisotropy parameter (vertical permeability) and taking it into account in existing geological and hydrodynamic models (using the Famennian deposit at the Gagarinskoye field as an example). For each lithological-facies zone of the Famennian deposit at the Gagarinskoye field, the dependence of the change in the permeability anisotropy parameter on the bottomhole pressure is obtained. It has been established that the values of the anisotropy index in various lithological-facies zones vary...
over a wide range. Using the obtained dependencies for estimating the permeability anisotropy parameter, the current geological and hydrodynamic model of the Famennian deposit at the Gagarinsky field was modified. Using a modified hydrodynamic model, it was possible to significantly improve the adaptation of both production and injection wells. Thus, the quality and reliability of the digital model of the Famennian deposit at the Gagarinsky field for calculating and predicting the oil production process has improved.

Using the technique described in the article, it is possible to evaluate the change in the permeability anisotropy parameter of other carbonate objects at Russian oil fields and further modify the existing geological and hydrodynamic models.

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