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ANALYSIS OF POSSIBILITIES FOR STABILIZING HYDROCARBON PRODUCTION DEPENDING ON THE STAGE OF DEVELOPMENT

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A B S T R A C T

Of key importance for planning the sustainable development of territories is the potential for stable production of hydrocarbon reserves, which can be expressed by the time of its duration. In the practice of developing oil and gas fields, two methods are known to stabilize production: through geological and technological measures that increase the productivity of wells and by regulating their operating modes. The second method, on the contrary, involves limiting the growth of selections at the initial stage of development. Due to this, the further decline in production turns out to be slower. Accordingly, the need for geological and technological measures is also decreasing. To describe the quantitative characteristics of production stabilization in both cases, a mathematical apparatus has been developed, based on the equations of state of hydrocarbons, the laws of underground hydrodynamics, as well as the work of specialists in the field of analysis and forecasting of the production of hydrocarbon reserves. It has been established that the processes of development of recoverable reserves of both oil and gas are subject to the same laws, and therefore can be described by means of one generalizing equation. Based on the equation, formulas are derived for calculating the duration of a stable production period depending on both the efficiency of intensification technologies and the degree of capacity redundancy, as well as the availability of recoverable reserves and the degree of their production. Calculations of the duration of the stable production stage for specific geological and technological conditions are presented.

Keywords: hydrocarbon production; geological and technological measures; operating mode; reserves development.

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Introduction

Under the conditions of rational development of hydrocarbon deposits (oil, natural gas), four periods are distinguished:

- period of production growth (as the deposit is drilled);
- period of production stabilization;
- period of production decline;
- development completion period.

Stabilization of production is achieved in one of two ways: by carrying out geological and technological measures to compensate for its decline, or by regulating the operation regime of wells. In the latter case, the control parameters are the depression values and operating time of each well.

The goals of stabilizing production in each of these cases are different. Geological and technological measures are carried out to ensure maximum production levels for a limited period [1, 2]. The end result is a reduction in additional development time - since the rate of reserve development increases, and the influence of geological and technical measures on their final value is either absent or not as significant as the effect on the rate of selection. A negative consequence (fig. 1) is a faster decline in production after the end of the stable period. In some conditions (for example, when developing an oil reservoir with water injection), there is also a sharp increase in water cut in well production and, as a consequence, an increase in operating costs [3, 4]. In other words, an improvement in the economic indicators of development due to geological and technical measures results in their deterioration at a later stage.

For deposits with hard-to-recover reserves, this negative effect (sharp watering) can be observed soon after the completion of the growth stage. Since some types of impact (for example, hydraulic fracturing) have limitations in application depending on the degree of watering [5], the subsoil user is forced to suspend or reduce the volume of geological and technical measures - and, thereby, move to the stage of production decline. For this reason, in many deposits the period of stabilization of production is either insignificant or absent altogether.

In contrast to the first option, stabilizing production by regulating well operation modes aims to extend the period of profitable development. By restraining the growth

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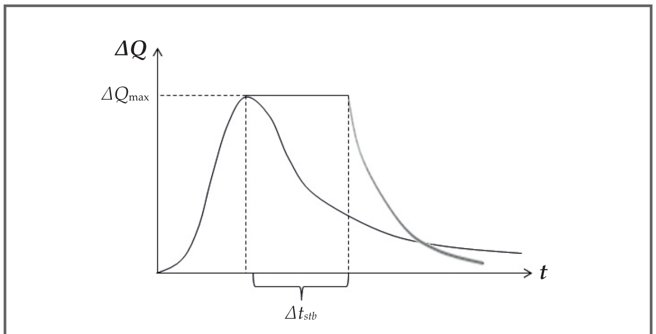

Fig. 1. Stabilization of hydrocarbon production through intensification (in the absence of the latter, growth is immediately replaced by a decrease)

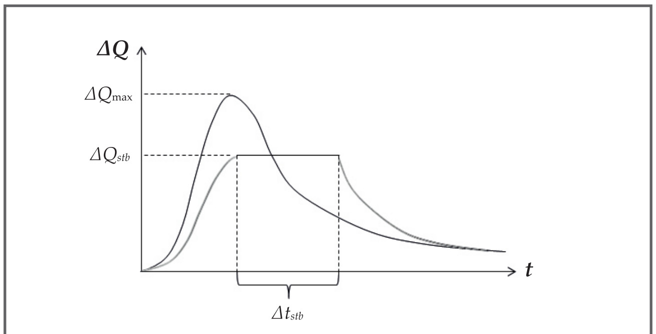

Fig. 2. Stabilization of hydrocarbon production by regulating the operating regime (stability is achieved due to the previous limitation of growth)

of production at the initial stage (fig. 2), the subsoil user subsequently achieves stabilization of extractions due to the gradual deepening of depressions, increasing the working time, and returning previously idle and inactive stock to production. The latter, by the way, is available even in the early stages of development.

During the period of growth, the economic effect of the above actions is ambiguous: on the one hand, lower production is equivalent to lower revenue for the subsoil user, on the other, operating costs also decrease [6]. In addition, savings can also be achieved in terms of capital investments: if the process of drilling out a deposit is extended over time, and some new wells are introduced during the stabilization period.

The benefit from the second stabilization option is fully manifested at the stage of production reduction. The decrease itself does not occur as sharply as in the first option; There are also no negative effects such as rapid watering of products or deterioration in the energy state of productive formations.

If stabilization according to the first option is feasible at any stage of development (including after reduction or stabilization according to the second option), then the second option requires careful planning from the very first years of operation of the deposit. Due to the lack of information about the reservoir during this period, stabilization of production according to the second option is almost never implemented in domestic field practice.

Stabilization through geological and technical measures best meets the interests of those subsoil users who are aimed at obtaining maximum profits in the shortest possible time. In turn, limiting production growth at the initial stage corresponds to the objectives of rational subsoil use, since it extends the period of profitable development and, accordingly, ensures the complete development of reserves to a greater extent.

As for the interests of both the owner of the subsoil (the state) and the territory, the economy of which largely depends on hydrocarbon production, any of the two options for stabilizing production is preferable for them to sudden changes in «growth and decline». In both cases, stability provides approximately the same socio-economic effect: it is expressed in stable employment and tax revenues.

In connection with the above, the potential for stable production, expressed by its duration, becomes of key importance for planning the sustainable development of territories. This work is devoted to the analysis and assessment of this time for both stabilization options.

Materials and methods

The issues of oil reserves production and its mathematical description have been worked out quite deeply, which resulted in the creation of a whole set of functional dependencies between the performance indicators of both individual wells and production facilities [7, 8]. Most of these dependencies were obtained empirically - based on the processing of technological indicators of real objects, through correlation analysis [9,10]. However, one of the most common functions, namely the linear relationship between the well flow rate and the accumulated production (as an option, between the current and accumulated production of the production facility) has a serious physical basis, namely the elastic properties of a Newtonian fluid. Under natural conditions, in the absence of external inflows, the flow rate of a well or a group of wells is equal to the decrease in the volume of elastic reserve over time:

$$q = -\frac{dQ^{\max}}{dt} = -V\beta\frac{d}{dt}\left(p - p_w\right) = -V\beta\frac{dp}{dt}$$

where V is the volume of oil-containing rock, $Q_{\max}$ is the maximum volume of oil that can be displaced under elastic conditions, β is the resulting compressibility coefficient, p is the current reservoir pressure, p_w is the pressure at the bottom of the wells (and it is also the minimum value to which it can reservoir pressure will decrease under this development mode).

On the other hand, based on the Dupuis formula and its modifications, the flow rate is proportional to the well productivity η and drawdown (p-p_w):

$$q = \eta\,(p - p_w)$$

Which, taking into account the initial value of reservoir pressure p_0 and when moving to dimensionless coordinates $\theta = \frac{p_0 - p}{p_0 - p_w}$, and $\tau = \frac{\eta t}{V\beta}$ allows us to obtain an equation of the following form:

$$\frac{d\theta}{d\tau} = 1 - \theta \qquad (1)$$

the solution to which is the asymptotic function

$$\theta = 1 - \exp(-\tau) \qquad (2)$$

In the works of V. D. Lysenko [11], expressions of the form (1) and (2) appear in a transformed form – which made it possible to generalize them for the conditions of the artificial flooding regime. With this assumption, θ was considered as the degree of production not of the elastic reserve of the deposit, but of its drained reserves Q_p – under a given regime, depending on the displacement and coverage coefficients. The expression for dimensionless time was transformed accordingly:

$$\tau = \frac{\eta\left(p_0 - p_w\right)t}{V\beta\left(p_0 - p_w\right)} = \frac{q_0 t}{Q_p}$$

where q_0 is the initial flow rate of the well. Based on equations (1) and (2), taking into account the specified transformations and assumptions, the following expressions were obtained to describe the production of oil reserves:

$$\frac{dQ_o}{dt} = q_0\left(1 - \frac{Q_o}{Q_p}\right)$$

where Q_o is cumulative oil production;

$$Q_o = Q_p\left(1 - \exp\left(-\frac{q_0 t}{Q_p}\right)\right);$$

$$q = q_0 \exp\left(-\frac{q_0 t}{Q_p}\right)$$

In their generalized form, these formulas are suitable for describing oil production processes both in natural mode and in the presence of a pressure maintenance system. In the latter case, the decrease in oil production was interpreted not as a consequence of a decrease in reservoir pressure, but as a result of watering the product and a decrease in the share of oil in the flow.

In the works of J. Arps [12] and R. I. Medvedsky [13], equation (1) was generalized to the form $\frac{d\theta}{d\tau} = \left(1-\theta\right)^{c+1}$, where c is a non-negative constant depending on the development mode and geological and physical conditions. By the way, the empirical dependences of relative oil permeability (equivalent to oil flow rate) on water saturation (equivalent to the degree of production of drained reserves) have a similar parabolic form.

At the same time, there are no similar developments to describe gas extraction. When predicting the development of gas reservoirs, either deterministic filtration models or corresponding solutions for oil (such as the exponential dependence of flow rate on time) are used. The latter is incorrect from a physical point of view, since the relationship between gas flow rate and pressure is nonlinear.

The objective of this study is to substantiate the characteristics of gas reserves production similar to equations (1) and (2) for oil. The ideal gas model is adopted as an assumption, i.e. gas, the pressure of which, at a constant volume of the medium, is directly proportional to its mass occupying this volume.

In this case, the degree of reserve depletion will be equal to the relative decrease in reservoir pressure:

$$\theta = \frac{Q_g}{Q_p} = \frac{p_0 - p}{p_0}$$

where Q_g is the accumulated gas production, and the drained reserves Q_p are usually taken as 100% of the geological reserves of the deposit.

And the change in accumulated production per unit time (flow rate) under normal conditions for ideal gas is proportional to the difference in the squares of reservoir and normal pressures and productivity:

$$\frac{dQ_g}{dt} = q = \eta\frac{p^2 - p_n^2}{p_n}$$

where p_n is normal atmospheric pressure (1 atm). Considering that the reservoir pressure is much higher than normal, the latter in the given difference of squares can be neglected:

$$q = \eta\frac{p^2 - p_n^2}{p_n} \approx \eta\frac{p^2}{p_n} = \frac{\eta p_0^2}{p_n}\left(1-\theta\right)^2 = q_0\left(1-\theta\right)^2 \qquad (3)$$

In the process of reducing the time derivative to dimensionless coordinates, we obtain the following:

$$\begin{cases} \dfrac{dQ_g}{dt} = Q_p\dfrac{d\theta}{dt} \\ \tau = \dfrac{q_0 t}{Q_p} \end{cases} \Rightarrow \left[\frac{dQ_g}{dt} = q_0\frac{d\theta}{d\tau}\right] \qquad (4)$$

Equating the right-hand sides of (3) and (4), after the necessary reductions we obtain:

$$\frac{d\theta}{d\tau} = \left(1-\theta\right)^2 \qquad (5)$$

The resulting equation (5) is a special case of the already mentioned equation $\frac{d\theta}{d\tau} = \left(1-\theta\right)^{c+1}$ with c=1. In turn, for the process of oil production under natural conditions, c=0 should be taken.

The general solution to equation (5) under the initial condition $\theta(0)=0$ will be the expression $\theta = \frac{\tau}{1+\tau}$ tending to unity as the development time tends to infinity - similar to (2). Based on this solution, we can obtain relations for the dynamics of production:

$$\frac{dQ_g}{dt} = q_0\left(1 - \frac{Q_g}{Q_p}\right)^2 \qquad (6)$$

$$Q_g = Q_p\left(\frac{q_0 t}{q_0 t + Q_p}\right) \qquad (7)$$

$$q = \frac{q_0}{\left(1 + \dfrac{q_0 t}{Q_p}\right)^2} \qquad (8)$$

Expression (7) in its form is equivalent to the Sipachev-Posevich displacement characteristic [14], obtained for the development of oil deposits using waterflooding. Expression (8) in turn is a special case of the so-called ALGOMES-1 [15] for n=1.

The results obtained indicate that the processes of extraction of fluids from a reservoir, even those with radically different physical properties, are subject to approximately the same laws - and, therefore, these laws are applicable not only for the classical regimes of oil displacement (elastic, rigid-water pressure), but also and when developing gas deposits (or deposits containing free gas).

When modeling various development modes, it is important to take into account special cases of the reserve depletion equation $\frac{d\theta}{d\tau} = \left(1-\theta\right)^{c+1}$, namely the values of the coefficient c corresponding to a particular case. Below, the table shows approximate values of this constant - based on [6], as well as taking into account the above calculations.

The works of A. Kh. Shakhverdiev [16, 17] proposed a methodology based on the same basic equation, but the

Table

Approximate values of the constant *c*

Values of the constant c	Development mode
from -1 to 0	extraction of oil from a reservoir underlain by water; as an option - in the presence of a gas cap or other factor of depletion of reserves with a finite development time
0	oil production in elastic mode
from 0 to 1	displacement of oil by water (hard water-pressure mode), in the conditions of a pore reservoir
1	gas extraction or displacement of oil from a complex deposit
>1	displacement of oil by water under conditions of extreme filtration heterogeneity of the formation, the presence of natural or man-made fracturing.

difference lies in the scope of application of the resulting models. Shakhverdiev's model describes the basic version of production dynamics, which includes (if we take into account the entire development period) three milestones - growth, inflection, decline. In this case, the option is considered when production tends to decrease, but the subsoil user tries to prevent this by increasing the amplitude. Unified methodology by A. Kh. Shakhverdiev is used to predict base production, and through it (by comparison with fact) - to assess the effectiveness of actually carried out geological and technical measures [17, 18].

The proposed model helps solve the inverse problem. When we set a target oil production indicator and from here we estimate how much the amplitude needs to be increased. Well, then, depending on the geological and technological conditions, we decide how to achieve this increase. Is it necessary (and is it possible) to drill additional wells? Or is it better to carry out intensification on those that exist? Or should part of the retired well stock be put back into operation?

Results

In dimensional and finite-difference form, the generalized equation for hydrocarbon production $\frac{d\theta}{d\tau}=(1-\theta)^{c+1}$ is as follows:

$$\Delta Q = A\left(1-\frac{Q}{Q_p}\right)^{c+1}$$

where ΔQ is production for a limited period of time (for example, a year), Q is production for the period preceding it from the beginning of development, A is the amplitude production of the deposit: it is equal to the production from all wells drilled on it in the case of their simultaneous launch in work.

During the growth period, production from the deposit reaches the value $\Delta Q_{\max}$ (fig. 1):

$$\Delta Q_{\max} = A\left(1-\frac{Q_R}{Q_p}\right)^{c+1} \tag{9}$$

where Q_R is the accumulated selections during the growth period. In order for production to remain at the same level until the end of the stable period Δt_{stb}, it is necessary to increase the amplitude by the intensification factor (K_I):

$$\Delta Q_{\max} = K_I \cdot A\left(1-\frac{Q_R+\Delta Q_{\max}\Delta t_{stb}}{Q_p}\right)^{c+1} \tag{10}$$

The increase in amplitude from A to $K_I \cdot$A is carried out progressively throughout the entire period.

Equating (9) and (10), we can express the time of stable production as a function of the intensification factor:

$$\Delta t_{stb} = \frac{Q_p - Q_R}{\Delta Q_{\max}}\left(1-\frac{1}{\sqrt[c+1]{K_I}}\right) \tag{11}$$

As mentioned earlier, production stabilization through the massive use of geological and technological measures can be realized at any stage of development, and not only at the end of the growth period. In this regard, the multiplier $\frac{Q_p - Q_R}{\Delta Q_{\max}}$ in general terms simply means the ratio of the residual (at the beginning of the stabilization period) recoverable reserves to the production rate, also called the ratio or reserve coverage. Based on this, formula (11) can be presented as follows:

$$\Delta t_{stb} = T\left(1-\frac{1}{\sqrt[c+1]{K_I}}\right) \tag{12}$$

where T is the inventory ratio. It is obvious that the duration of stable production directly depends on this value, although it is obviously strictly less than it.

In turn, with the second stabilization option, the growth does not go to level (9), but is limited by the value in ΔQ_{stb}:

$$\Delta Q_{stb} = A^*\left(1-\frac{Q_R^*}{Q_p}\right)^{c+1} \tag{13}$$

where A^*, Q_R^* is lower than A and Q_R from formula (9). By the end of the stable period, the amplitude is brought to its base value, thereby maintaining the rate of extraction of the produced fluid:

$$\Delta Q_{stb} = A\left(1-\frac{Q_R^* + \Delta Q_{stb}\Delta t_{stb}}{Q_p}\right)^{c+1} \tag{14}$$

To solve the system of equations (9) and (14), we introduce a capacity reserve coefficient (K_{rm}) equal to the relative underestimation ΔQ_{stb} compared to the maximum value of withdrawals ΔQ_{max}:

$$K_{rm} = 1-\frac{\Delta Q_{stb}}{\Delta Q_{\max}}$$

A similar relationship can be accepted for Q_R^* and Q_R, if we assume that production growth throughout the corresponding period was limited proportionally - as shown in figure 2.

$$K_{rm} = 1-\frac{Q_R^*}{Q_R}$$

Based on these relations, we transform expression (9):

$$\left[\frac{\Delta Q_{stb}}{1-K_{rm}} = A\left(1-\frac{Q_R^*}{(1-K_{rm})Q_p}\right)^{c+1}\right] \Rightarrow$$
$$\Rightarrow\left[\Delta Q_{stb} = A(1-K_{rm})\left(1-\frac{Q_R^*}{(1-K_{rm})Q_p}\right)^{c+1}\right] \tag{15}$$

Equating (14) and (15), we express the time of stable production:

$$\Delta t_{stb} = \frac{Q_p - Q_R^*}{\Delta Q_{stb}}\left(1-\left(1-\frac{K_{rm}}{1-K_{ex}}\right)\frac{1}{(1-K_{rm})^{\frac{c}{c+1}}}\right) \tag{16}$$

where K_{ex} is the production coefficient of initial recoverable reserves: the share of their selection in the period preceding stabilization:

$$K_{ex} = \frac{Q_R^*}{Q_p}$$

The multiplier $\frac{Q_p - Q_R^*}{\Delta Q_{stb}}$ can be presented as a multiple of reserves - by analogy with (12), and can also be considered as a function of the rate of selection from the initial recover able reserves: $\delta = \frac{\Delta Q_{stb}}{Q_p}$. Accordingly, expression (16) can be reduced to one of two forms:

$$\Delta t_{stb} = T\left(1-\left(1-\frac{K_{rm}}{1-K_{ex}}\right)\frac{1}{(1-K_{rm})^{\frac{c}{c+1}}}\right) \tag{17}$$

$$\Delta t_{stb} = \frac{1-K_{ex}}{\delta}\left(1-\left(1-\frac{K_{rm}}{1-K_{ex}}\right)\frac{1}{(1-K_{rm})^{\frac{c}{c+1}}}\right) \tag{18}$$

As in the previous case, see (12), the time of stable production is directly proportional to and strictly less than the reserve ratio. In addition, it is easier to keep production at a stable level, the lower this level and the smaller part of the initial recoverable reserves was produced in the previous period.

Examples of calculations

Example 1. The reserve ratio for developed oil fields located in the Khanty-Mansi Autonomous Okrug - Yugra averages 25.5 years. Modern intensification technologies provide a relative increase in productivity in a wide range of values: from a level slightly above one (treatment of the near-wellbore zone) to approximately 3 times (high-volume hydraulic fracturing, drilling of sidetracks). The values of the constant c for the development of oil fields, according to the table, lie in the range from 0 to 1; In addition, the case c=2, corresponding to conditions unfavorable for development, was considered. The results of estimates of the period of stable production using formula (12) for the specified conditions are shown in figure 3.

The optimal duration of stable production, as can be seen in figure 3, lies in the range from 10 to 15 years. If we assume that the prospects for oil production in the Khanty-Mansi Autonomous Okrug are associated mainly with hard-to-recover reserves (c=2), then this value is reduced to 6-8 years. The time of stable production with c in the range from 0 to 1 is reduced to the same level if the subsoil user gives preference to cheaper and less efficient intensification technologies (K_I≈1.5).

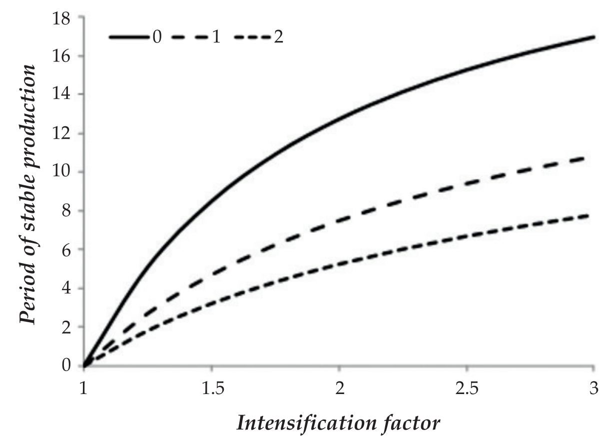

Fig. 3. Results of estimates of the time of stable oil production from the fields of Khanty-Mansi Autonomous Okrug - Yugra, subject to the systematic application of measures to intensify production (for the value of the constant *c*, respectively, 0, 1 and 2)

Example 2. The oil reservoir is complex, but without fracturing (c=1). The reservoir properties of the deposit, coupled with the production capabilities of the subsoil user, make it possible to achieve a withdrawal rate from the initial recoverable reserves of up to 8%, while for rational development a rate of no more than 5% is sufficient (K_{rm}=37.5%). If during the period of production growth 20% of the initial recoverable reserves are extracted, then the subsequent period of stable production (with a withdrawal rate from the initial recoverable reserves of 5%), according to (18) will be:

$$\Delta t_{stb} = \frac{0.8}{0.05}\left(1-\left(1-\frac{0.375}{0.8}\right)\frac{1}{(1-0.375)^{\frac{1}{2}}}\right) =$$
$$= 16\cdot(1-0.5312\cdot 1.265) = 5.24$$

that is, approximately 5 years. By the end of the stable period, accordingly, the selection from the initial recoverable reserves will reach 45%.

Example 3. A single oil well drains reserves of 140 thousand tons. There are no waterflooding sources nearby (c=0). With a drawdown of 7 MPa, an oil flow of 50 tons/day was obtained from the well, which quite suits the subsoil user in terms of economic efficiency. The initial reservoir pressure is 23 MPa, the saturation pressure is 8 MPa, i.e. the depression can be deepened to a maximum of 15 MPa by reducing the pressure at the bottom to the saturation pressure level. At the same time, some experts believe that the bottomhole pressure can be reduced to 70% of the saturation pressure without the risk of dissolved gas manifestations. Accordingly, the depression can be deepened to 17.4 MPa.

So, in the first case, the capacity reserve ratio will be 53.3%, in the second – 59.8%. If the well operates every 9 out of 10 days a year (328.5 days in total), a flow rate of 50 tons/day will correspond to an annual oil production of 16.4 thousand tons. If it is maintained at this level from the very beginning of development (K_{ex}=0), and use only depression regulation as a means of support, then the time of stable production will be: in the first case –

$$\Delta t_{stb}=\frac{140}{16.4}\left(1-\left(1-\frac{0.533}{1}\right)\right)=0.533\cdot 8.53=4.5$$

and in the second case –

$$\Delta t_{stb}=\frac{140}{16.4}\left(1-\left(1-\frac{0.597}{1}\right)\right)=0.597\cdot 8.53=5.1$$

Thus, by regulating the depression in this case, it is possible to maintain the well flow rate at a stable level for 4-5 years. A decrease in bottomhole pressure below the saturation pressure is assessed as ineffective, since it did not have a significant impact on the duration of the stable period.

Example 4. At the end of a stable 5-year period, hydraulic fracturing (K_l=2) is planned for the well in order to extend this period. By regulating the operating mode and timely hydraulic fracturing, flow rate surges can be avoided. Taking into account the fact that in the previous period the well produced 16.4·5=80.2 thousand tons, due to intensification, production can be stabilized for 1.8 years.

Conclusion

1. In the practice of developing oil and gas fields, two methods are known to stabilize production: through geological and technological measures that increase the productivity of wells and by regulating their operating modes. In the latter case, stability is achieved by reserving capacity at the initial stage of development and then commissioning it to compensate for the decline in production.
2. As shown by the analysis of the equations of state of hydrocarbons, the laws of underground hydrodynamics and statistical dependencies, the processes of development of recoverable reserves of both oil (and, under different development modes) and gas, obey the same laws, and therefore can be described using one, a generalizing equation. Particular cases of this equation are found in a number of literary sources devoted to the analysis of oil and gas production indicators using mathematical methods [20-22].
3. Examples of calculations using the resulting equation make it possible to estimate the period of stable production, achievable under existing geological and technological conditions, at a level of the order of several years. It has also been established that at sites with unfavorable development conditions (and reserves that, accordingly, can be classified as hard-to-recover), the achievable time of stable production is shorter.
4. The consistent use of two methods of stabilizing production (through capacity reservation and through geological and technical measures) allows us to count on a longer period of its maintenance - about 10 years, which will contribute to better planning of economic activity, both at the level of individual fields and at the level subjects of the Russian Federation. In addition, over such a significant period of time, the emergence and mass introduction of new technologies cannot be ruled out, expanding the possibilities for increasing and maintaining hydrocarbon production. An example of such a technological solution over the last decade is the drilling of horizontal wells with multi-zone hydraulic fracturing.
5. Of particular importance when solving the problem of maximizing the extension of the period of stable production is regular monitoring of such a value as the ratio of hydrocarbon reserves. As follows from the calculations performed within the framework of the article, the reserve ratio should be comparable to the target duration of the stabilization period, slightly exceeding it. A low inventory ratio indicates the need to reserve capacity. A multiple excess of the target duration of the stable period by this indicator is, incl. a sign of insufficiency of the applied geological and technological measures.

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