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MODELLING THE DEVELOPMENT OF OIL RIM USING WATER AND GAS INJECTION

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Abstract. In this study, water injection and gas injection technologies are examined for their effectiveness in developing oil rims in gas fields. Considering the need for advanced development of the oil rims within a short period of time, reservoir simulation methods using horizontal wells have been used to rationally develop oil rims. It was confirmed that large volumes of gas must be injected to maximize oil recovery. This happens when gas breakthroughs from the gas cap into the bottom of the production well and from the injection well into the gas section. A cycle process was discovered when gas injection led to the development of an oil rim. The condensate from the gas was taken out, and the dryer gas was then injected back into the reservoir. Condensate concentrations in the gas, especially those near the oil rim, are a major factor contributing to the interest in the proposed concept.

Keywords: gas injection; water injection; oil rim; reservoir simulation; oil recovery

1, Introduction

This work aims to analyze the effectiveness of technologies for the development of oil rims on gas fields through water injection or gas injection. There are various technologies and systems available for developing oil and gas deposits around the world and at home (Al-Obaidi &Khalaf 2019; Al-Obaidi 2021; Davarpanah & Mirshekari 2018; Kosachuk, Sagitova, & Titova 2005; Krasnova, Marakov, Krasnov et al. 2014). This illustrates the complexity of the issue at hand, as well as the importance of tailoring the development of each hydrocarbon deposit to its needs. It is mainly the occurrence of oil, gas, and water within the same hydrodynamic system that creates problems, as well as a number of other factors that influence the efficient development of oil and gas reserves. These factors primarily include the ratio of oil and gas reserves, the reservoir properties of productive formations, the physicochemical properties of fluids and the activity of the natural water drive system (AL-Obaidi, Smirnov & Khalaf 2020; Smirnov & Al-Obaidi 2008; Zakirov 1998; Zheltov, Martos, Mirzadzhanzade & Stepanova 1979). Clearly, indicators like the level of raw material prices, the tax policy in force in the area of oil production, and so on are important.

According to many studies (Al-Obaidi 2016a; Al-Obaidi 2016b; Fernie, Zhou, McCarthy et al. 2018; Julian, Toochukwu, Princewill et al. 2019; Nykjaer 1994), the simultaneous and advanced development of a gas cap leads to a rapid disintegration of the oil rim and, consequently, to irretrievable oil losses. On the other hand, the long-term development of the oil rim results in the conservation of gas reserves and a decline in the economic indicators of field development. Considering the need for advanced development of the oil rims within a short period of time, reservoir simulation methods using horizontal wells can be used to rationally develop oil rims. When horizontal wells are used, less drawdowns and overbalances are experienced, reducing the chances of gas and water entering production well bottomholes (Azis & Settari 1982; Hofmann, AL-Obaidi & Kamensky 2021; Hofmann, Al-Obaidi & Patkin 2013; Olabode, Isehunwa, Orodu et al. 2021; Song, Fan, Zhao et al. 2013). This development technology is the subject of research in this paper.

2. Methodology

2.1. Identifying the problem and describing the model

In order to assess the efficiency of oil recovery by injecting water or gas into the oil rim, it is proposed to solve a two-dimensional, three-phase flow profile problem. The area under consideration is an element of the development of the oil rim (Fig. 1).

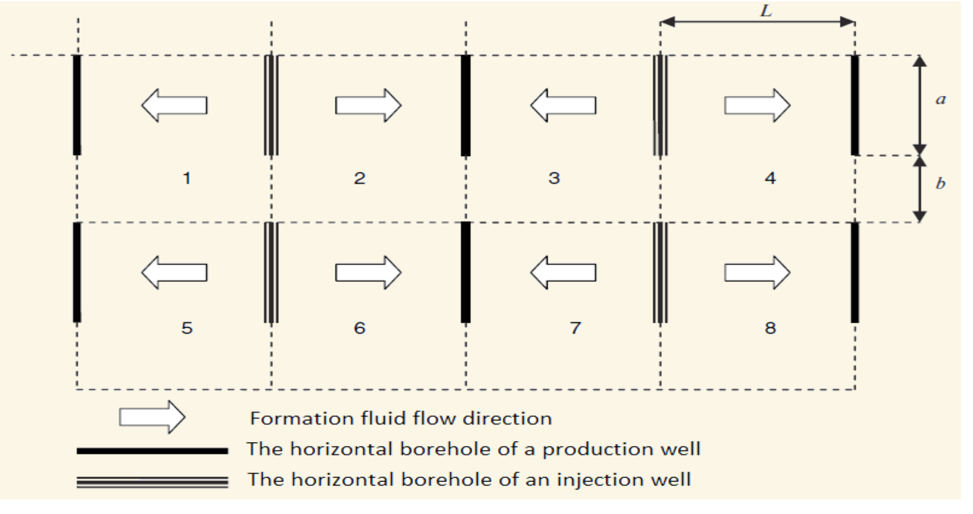

Figure 1. Schematic placement of 8 development elements on a fragment of the deposit

The development element consists of half (along the axis) of the horizontal section of the production well and half of the horizontal section of the injection well. It is considered that the boundaries of the area occupied by the development element are impenetrable. The oil rim is located under the gas cap, underlain by an aquifer from below.

In this study, a two-dimensional problem (task) was chosen instead of a three-dimensional model because of the following reasons:

1) As the problem dimensions increases, conditions for convergence of the calculation scheme and the accuracy of the results deteriorate;

2) The length of the horizontal wellbore exceeds the distance between the wells (a > b), therefore, in most of the development element, the flow in the direction perpendicular to the vertical plane is negligible.

To ensure high accuracy in solving the problem (task) posed, it is proposed to use implicit difference schemes and fine (detailed) grids.

To rationally develop oil rims, reservoir simulation methods using horizontal wells can be used in light of the need for advanced development in a short period of time. In order to solve this task, the following assumptions must be met.

There is underlying water in the model and the lower boundary of the water zone is impermeable. During the process under consideration, underlying water is important, and the natural water-driven system (NWS) interacts only to a limited extent with the injection of water or gas into injection wells. Oil and gas fields, however, have a different issue when it comes to identifying NWS activity.

The vertical boundaries of the area are impermeable, except for the nodes that coincide with the positions of the wells, in which the modes of their operation are set. In addition to the fact that fluids do not flow between development elements, wells have the same impact on the development elements of which they are a part as well (AL-Obaidi, Hofmann, Khalaf et al. 2021; Chang, AL-Obaidi & Patkin 2021; Hofmann & Hofmann 1992). No interference is taken into account since the main focus is on modelling the process occurring between the injection and production horizontal wells.

Modelling a massive gas cap allows taking into account the ratio of oil and gas reserves in the reservoir and the elastic energy reserve of the gas part, which strongly affects the development of the oil rim. Considering the low viscosity of natural gas and the rapid equilibration of pressure in the gas during the development process for real deposits, the placement of a gas cap above the oil layer makes sense in the model.

The construction of the model is based on linear flow according to Darcy's law (Khoury, Ali, Hassall et al. 2016; Soliman & Dusterhoft 2016). Additionally, relative phase permeability, permeability distribution, as well as anisotropy, are taken into account, along with pressure-dependent permeability and fluid viscosity. No consideration is made of capillary pressure, solubility, or gravitational forces. In support of the last two assumptions, it is worth noting that, first, gas output from oil and condensate precipitation from gas is insignificant at low drawdowns, where production wells are operated, and, second, gravitational forces are usually not significant when developing thin oil rims in low-permeability reservoirs (Hofmann, AL-Obaidi & Kamensky 2021; Lawal, Yadua, Ovuru et al. 2020).

According to the continuity equation, the i-th phase has the following form (Liu, Wang, Luo et al. 2021; Szanyi, Hemmingsen, Yan et al. 2018):

$$\frac{\partial}{\partial x}\left(k_x \frac{k_i}{\mu_i\beta_i}\frac{\partial p}{\partial x}\right) + \frac{\partial}{\partial y}\left(k_y \frac{k_i}{\mu_i\beta_i}\frac{\partial p}{\partial y}\right) = \frac{\partial}{\partial t}\left(\varphi \frac{s_i}{\beta_i}\right) \;, \quad i = 1{,}3, \tag{1}$$

Where water, gas, and oil are represented by 1, 2, and 3; x and y indicate horizontal and vertical axes; p = f(x, y, t) is the required field pressure that changes over time (t). K_x, K_y - distribution of absolute permeability depending on pressure; $k_i = f(s_i)$ is the relative phase permeability; μ_i, $\beta_i = f(p)$ are the dependences of viscosity and the volumetric coefficient on pressure, respectively; φ is porosity; s_i is phase saturation. After a series of mathematical transformations, taking into account $\sum_{i=1}^{3} s_i = 1$, we obtain a differential equation of parabolic type:

$$\sum_{i=1}^{3}\left\{\beta_i \frac{\partial}{\partial x}\left(k_x \frac{k_i}{\mu_i\beta_i}\frac{\partial p}{\partial x}\right) + \beta_i \frac{\partial}{\partial y}\left(k_y \frac{k_i}{\mu_i\beta_i}\frac{\partial p}{\partial y}\right)\right\} = \sum_{i=1}^{3} \varphi\beta_i s_i \frac{\partial}{\partial p}\left(\frac{1}{\beta_i}\right)\frac{\partial p}{\partial t} \tag{2}$$

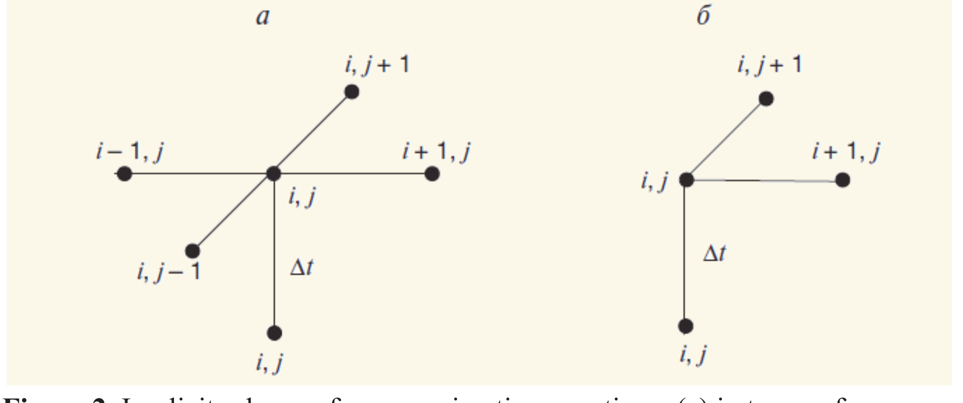

Figure 2. Implicit schemes for approximating equations: (a) in terms of pressure; (b) - by saturation

After several mathematical transformations, equation (1) is reduced to a hyperbolic form:

$$k_i \frac{\partial}{\partial x}\left(\frac{k_x}{\mu_i\beta_i}\frac{\partial p}{\partial x}\right) + \frac{k_x}{\mu_i\beta_i}\frac{\partial p}{\partial x}\frac{\partial k_i}{\partial s_i}\frac{\partial s_i}{\partial x} + k_i \frac{\partial}{\partial y}\left(\frac{k_y}{\mu_i\beta_i}\frac{\partial p}{\partial y}\right) + \frac{k_y}{\mu_i\beta_i}\frac{\partial p}{\partial y}\frac{\partial k_i}{\partial s_i}\frac{\partial s_i}{\partial y}$$

$$= \frac{\varphi}{\beta_i}\frac{\partial s_i}{\partial t} + \varphi s_i \frac{\partial}{\partial p}\left(\frac{1}{\beta_i}\right)\frac{\partial p}{\partial t} \;, \quad i = 1{,}3 \tag{3}$$

A system of partial differential equations describing three-phase filtering in two dimensions is described by equations (2) and (3). The equations are solved numerically under given initial and boundary conditions.

In this work, "implicit schemes" of time approximation are used for both the parabolic pressure equation and hyperbolic saturation equations (Fig. 2). An iterative algorithm is used to calculate pressure and saturation fields for a new temporary layer (Fig. 3). The algorithm starts by solving parabolic equations with respect to pressure, in which the saturation fields are used as the input, and then it solves hyperbolic equations with respect to saturation based on the input of obtained pressure.

Following this, the resulting saturation distribution is used to refine the pressure field in the next iteration, and so on. The iterative process continues until the exit condition from iterations is met. In addition, at each iteration, the nonlinear and quasi-linear terms of the system equations are specified. A high degree of accuracy can be achieved by using the described calculation algorithm. On fine grids, only implicit schemes can be used to solve the system of equations describing fluid flow in reservoirs.

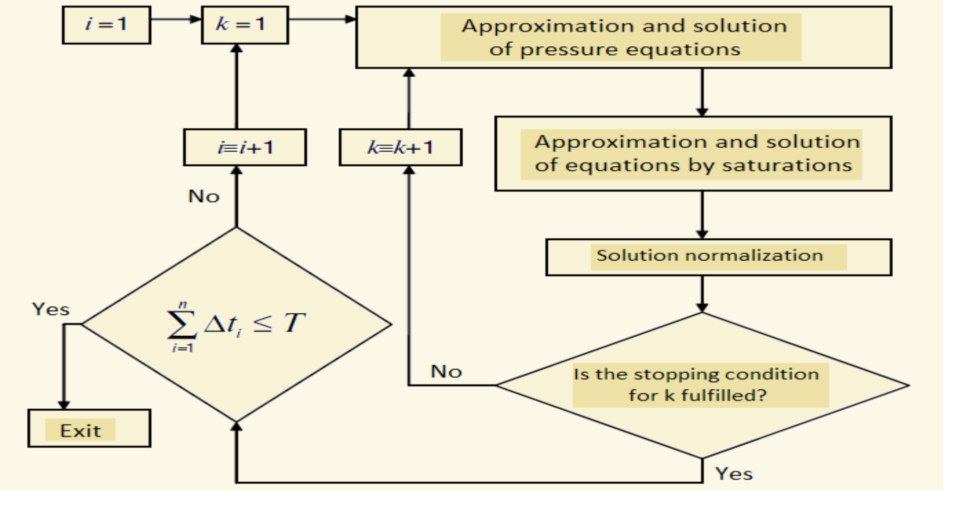

Figure 3. Scheme of the algorithm

Due to the strict requirement for a time step in fine grids, "explicit schemes", often used to model entire fields, do not fit the task at hand. The iterative method of solving equations is essential since the first iteration gives a poor approximation to the solution on fine grids, and the more iterations, the more accurate the result becomes. By implementing the algorithm for automatically selecting the time step, the overall number of temporary layers in the development period is as low as possible. This reduces the negative effect of error accumulation.

Using viscosity, permeability, volumetric coefficient on pressure, phase permeability on saturation, initial data conditions, and boundary conditions, a Matlab program was developed to simulate oil displacement from the oil rim.

3. Results and discussions

3.1 The initial data for the numerical simulation

As an example, let us consider the cases of oil displacement by water and oil displacement by gas under identical conditions and analyze the results. The tasks were solved for the following conditions: L = 100 m – distance between wells, h_o = 25 m – oil rim thickness, h_g = 50 m – gas cap thickness, h_w = 25 m – water cushion thickness, k_x = 0.1 μm^2 – horizontal formation permeability, $k_a = k_y / k_x = 0.1$ – anisotropy coefficient, μ_o = 2 mPa s – oil viscosity, μ_w =1 mPa s – water viscosity, μ_g = 0.1 mPa s – gas viscosity, $\beta_o = 1$ is the oil volume factor, β_w =1 is the water volume factor, $\beta_g = 10^5/p$ is the gas volume factor, r_w = 0.1 m is the radius of the wells made according to the nature of the opening, the wells are located in the middle between the water oil contact (WOC) and the gas oil contact (GOC). Dependences of phase permeability are taken from the example given in (Krylov 2003), the graphs of which are given in Fig. 5:

$$k_o(s_o) = 1{,}6(s_o - 0{,}2)^{2{,}1} \tag{4}$$

$$k_w(s_w) = 0{,}9(s_w - 0{,}25)^{2{,}2} \tag{5}$$

$$k_g(s_g) = 0{,}75(s_g - 0{,}1)^{1{,}5} \tag{6}$$

Initial conditions: p_i = 10 MPa – initial formation pressure. Saturation distribution:

$$(S_o;S_w;S_g) = \begin{cases} (0; 0.25; 0.75), & n > n_{GOC} \\ (0.75; 0.25; 0), & n_{GOC} \geq n > n_{WOC} \\ (0; 0; 1), & n \leq n_{WOC} \end{cases} \tag{7}$$

Boundary conditions: $(P_{wf})_p$ = 9.6 MPa - bottom hole pressure in the production well, $(P_{wf})_{in}$ = 10.4 MPa - bottom hole pressure in the injection well, $\partial p/\partial r = 0$ - impermeable boundary condition, $(S_w)_{in}$ = 0.8 - water saturation in the injection well when water is injected. The problem was solved using a uniform grid with dimensions MN = 101 * 11 nodes (n), where M is the number of nodes along the y-axis, and N is the number of nodes along the x-axis. The pressure in the node and the pressure in the well are related by the relationships given in (Kanevskaya 2002).

3.2 Simulation results of water injection

Based on the calculations, a graph was generated that plotted the oil recovery factor RF_o and gas recovery factor RF_g against $\rho = \frac{(v_w)_{in}}{(v_o)_i}$, which is the ratio of the volume of water injected to the initial volume of oil in the element (Fig. 4).

It is due to the relatively small ratio between gas and oil volumes that the high gas recovery factor has been achieved during the development of the oil rim. In this example, the ratio is 2, but it often exceeds 20 in real oil and gas fields. For real fields, with a significant predominance of gas reserves over oil reserves, the inevitable gas extraction during the development of the oil rim will not lead to a significant decrease in pressure in the gas cap, since only a small portion of the gas reserves will be exploited.

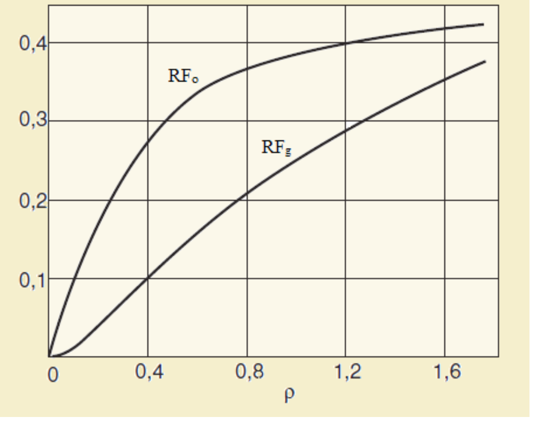

Figure 4. Dependence of oil and gas recovery on the injected volume of water

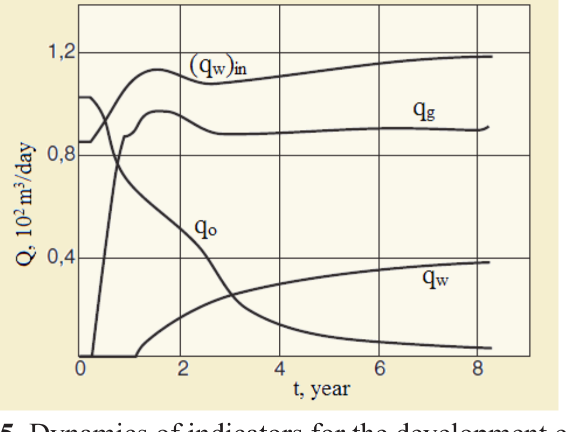

Figure 5. Dynamics of indicators for the development element

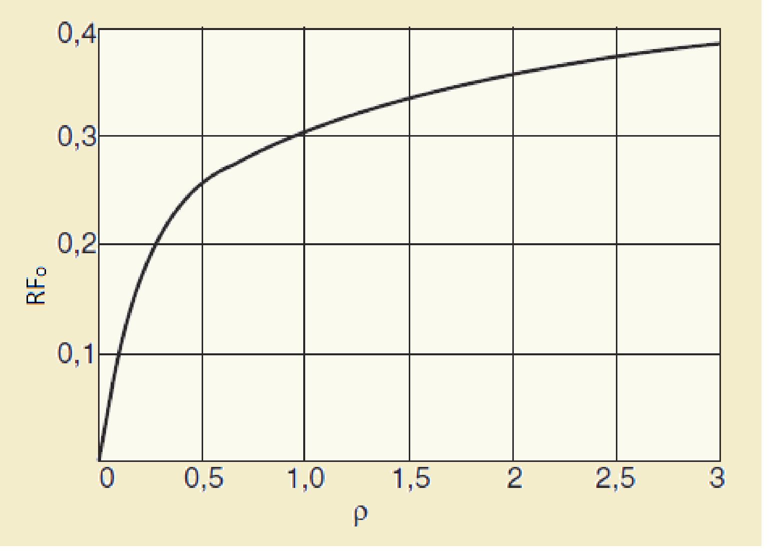

Figure 6. Dependence of oil recovery on the injected volume of gas

The dynamics of changes in oil flow rates q_o, gas flow rates q_g, and water flow rates q_w at reservoir conditions, as well as the volume of water injection $(q_w)_{in}$ for the development element are shown in Fig. 5. It is important to note that one production well works with two development elements.

Therefore, for a real well, the indicators will be twice as high as those given. In this case, the length of the horizontal wellbore is 500 m.

According to the calculations, waterflooding as an artificial reservoir stimulation method allows the main oil reserves in the oil rim to be incorporated into the development process, which would not be possible under natural circumstances. Waterflooding causes coning formation, migration of oil into the gas and water portions of the reservoir, resulting in the destruction of the oil rim, which in turn causes inevitable oil losses.

Oil is "smeared" over the reservoir by the water, which outpaces the oil and mixes with the gas. As a result, water flooding of the gas part is observed, which, of course, negatively impacts the gas recovery factor. Gas reserves have been negatively affected by the oil rim development process with waterflooding, and this issue needs to be addressed separately.

Despite the fact that the proposed technology has a number of negative aspects, waterflooding may be a rational and applicable way of modifying the reservoir for oil rim development in oil and gas condensate deposits.

3.3 Results of the gas injection simulation

Using similar initial conditions, the results of gas injection simulations are presented below. The gas saturation in the injection well is equal to $(S_g)_{in} = 0.55$. Based on the computations performed, figure 6 depicts the graph of the dependence of oil recovery RF_o on $\rho = \frac{(v_g)_{in}}{(v_o)_i}$, which is the ratio between the volume of gas injected under reservoir conditions, and the initial volume of oil in the reservoir.

The dynamics of changes in the flow rates of oil q_o, gas q_g and water q_w, adjusted for reservoir conditions, as well as the volume of gas injection $(q_g)_{in}$ for the development element are shown in Fig. 7. The length of the horizontal wellbore is chosen to be 500 m.

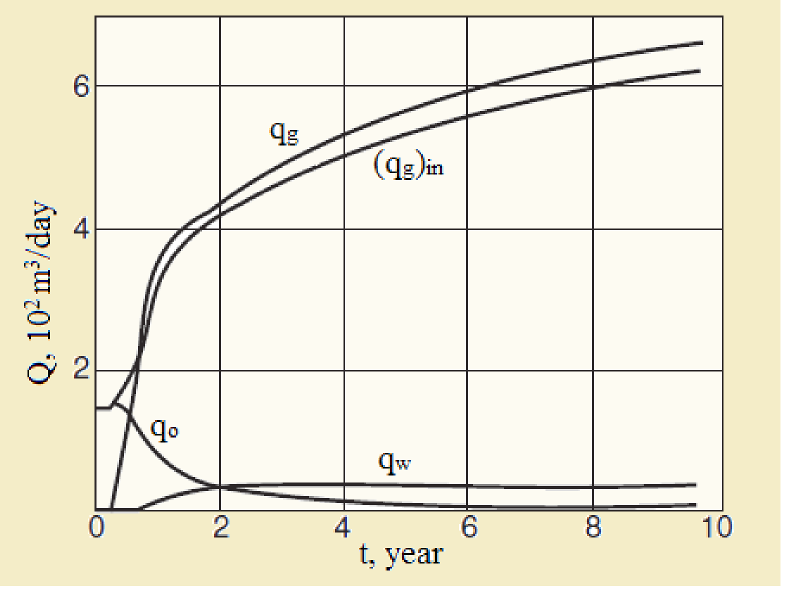

Figure 7. The dynamics of indicators of the development element

3.4 The effect of oil rim thickness on oil recovery

The program developed within the framework of this study simulates the displacement of oil from the oil rim and allows the influence of various factors on the indicators of technological development to be analysed. Let us consider the effect of oil rim thickness on oil recovery in the case of using water as a displacing agent.

It is obvious that the greater the thickness of the oil rim h_o, the lower the anisotropy coefficient $k_a = k_y / k_x$, and the shorter the distance between horizontal wells L, the higher the recovery factor. Consider, for example, $h_o = 25$ m, L = 100 m, ka

= 0.1. Then, when water is injected into the oil rim, the recovery factor is 38% (for pumping water in the amount of one pore volume) and 44% (for pumping water in the amount of two pore volumes).

In this section, let's examine the influence of the dimensionless parameter $\varepsilon = h_o/L$ on the oil recovery in the element. The following are the results of several numerical experiments. The given task was solved for various values of $L \in \{80, 100, 120, 140, 180, 220$ m$\}$, i.e. for the following values of $\varepsilon \in \{0.31; 0.25; 0.21; 0.18; 0.14; 0.11\}$. The rest of the dependencies and initial data are taken from the case previously considered. The graphs in figure 8 show the dependence of the oil recovery factor on the ratio of the accumulated volume of injected water to the initial volume of oil ρ for various values of ε.

At $\rho = 1$, Fig. 9 shows the dependence of the oil recovery factor on ε.

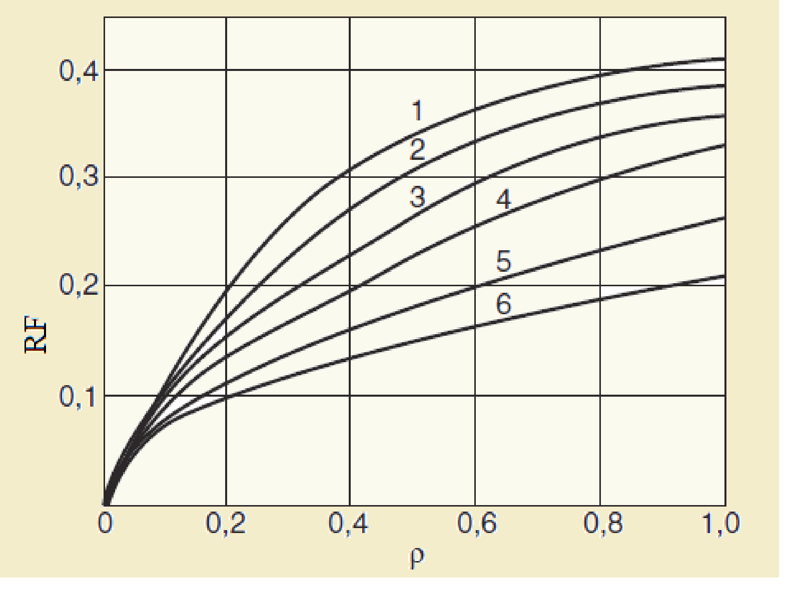

Figure 8. Dependence of oil recovery factor on injected water volume for formation with anisotropy ka = 0.1 for different values of ε: 1 – 0.31; 2 - 0.25; 3 - 0.21; 4 - 0.18; 5 - 0.14; 6 - 0.11.

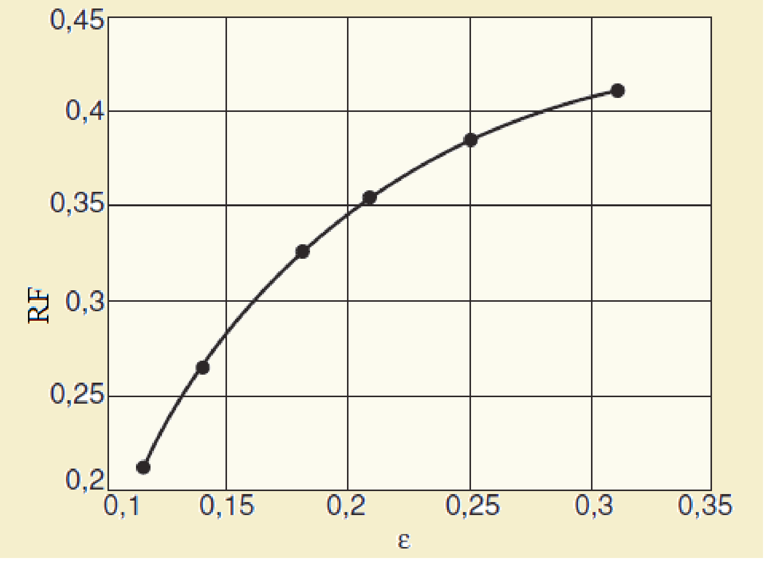

Figure 9. dependence of the recovery factor (RF) on ε at ρ = 1.

4. Conclusions

The results of calculations show that gas injection, as an artificial stimulation technique, allows for the development of the major oil reserves in the oil rim. As with water injection, inevitable processes are observed during the process of gas injection: oil migration into gas and water zones, breakthrough of the displacing agent into gas and water regions, and formation of water and gas cones.

The gas injection case is characterized by large volumes of gas production and injection. To achieve high oil recovery factors, it is necessary to inject large volumes of gas.

The gas injection case involves large volumes of gas being produced and injected. In order to achieve high oil recovery rates, large volumes of gas must be injected. This happens when gas breakthroughs from the gas cap into the bottom of the production well and from the injection well into the gas section. This confirms that the development of an oil rim through gas injection enables a cycle process to be employed when condensate is taken from the produced gas, and the dried gas is then re-injected into the reservoir. It is the high concentration of condensate in the gas, especially in the area near the oil rim that contributes to the interest in the proposed technology. The combined processes of oil production from the rim and gas condensate require a separate, more detailed study.

Therefore, based on the results of these studies, it is likely that the development of gas and gas condensate fields using horizontal wells and reservoir pressure maintenance systems can be a profitable project, which is supported by high oil prices and the constant development of horizontal drilling.

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