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MODELING OF THE PROCESSES OF DEVELOPMENT OF GAS CONDENSATE FIELDS IN THE DEPLETION MODE

Kh. A. Feyzullayev*[1], M. S. Khalilov[2], A. A. Damirov[3]
[1]*«OilGasScientificResearchProject» Institute, SOCAR, Baku, Azerbaijan*
[2]*Baku State University, Baku, Azerbaijan*
[3]*Lankaran State University, Lankaran, Azerbaijan*

ABSTRACT

Based on mathematical modeling under the influence of capillary and gravitational forces of condensate operating in depletion mode, settling in the gas-condensate layer, as a result of redistribution in height, the formation of a technogenic-condensate flow at the gas-water boundary and the production of condensate by a horizontal well drilled into it were studied. Initially, when exploiting a gas condensate formation with a five-point production well, the nature of the distribution of reservoir pressure and phases along the height, the time of formation of technogenic condensate and the interval of its location along the height of the gas field were determined. In the second case, the process of water exposure was realized by exploiting the formation with production wells to remove condensate with a horizontal well drilled into a technogenic condensate deposit. Mining wells reveal the productive height of the formation in two ways: in the first case from the upper part, in the second case from the lower part, and after entering the condensate flow, the horizontal well is introduced into operation. Exposure to water ends at 98% dilution of the horizontal well product. The results of calculations show that the formation of technogenic condensate at the water-gas interface in the reservoir depletion mode is the result of the segregation process. The greatest effect in increasing the condensate yield of a horizontal well drilled into a technogenic condensate field is achieved by pumping water from the upper part of the formation.

KEYWORDS:
gas-condensate reservoir;
segregation process;
technogenic condensate fringe;
horizontal well;
condensate recovery coefficient.

***e-mail:** xasay.feyzullayev@socar.az

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Introduction

Development of gas condensate fields in depletion mode is the most frequently used method. This process is accompanied by a decrease in reservoir pressure and losses in the depths of the field of valuable hydrocarbon raw materials, especially high-boiling hydrocarbons. As a result, it is impossible to achieve high recovery rates from the reservoir not only for liquid hydrocarbons, but also for gas.

Conventional secondary methods for extracting condensate deposited in the formation are characterized by low technological efficiency and low cost-effectiveness [1-8].

A number of impact technologies have been developed to increase the component efficiency of gas condensate fields. These technologies are based on reducing retrograde condensate precipitation or removing precipitated condensate from depleted or depleting reservoirs by maintaining the reservoir pressure at the initial condensation pressure or maximum condensation pressure level. Various working agents are used for this purpose. Numerous studies [6, 7, 9-16] have been conducted in this area, which can be roughly divided into two groups. The first group focuses on reducing retrograde condensate precipitation by maintaining the reservoir pressure above the initial condensation pressure, while the second group addresses retrograde condensate management in fully or partially depleted reservoirs using various methods.

The cost of injecting gas or other fluids into the reservoir to maintain the reservoir pressure increases, and fluid losses in the reservoir reduce the economic efficiency of condensate production. In the second approach, the method involves using hydrocarbon and non-hydrocarbon gases to vaporize the liquid condensate accumulated in the reservoir and wellbore zone by injecting gas, with part of it being forced into production wells. However, this leads to certain problems, such as significant changes in the gas-condensate system parameters due to the interaction with injected non-hydrocarbon agents, the difficulty of separating the produced products from the reservoir hydrocarbon system and the injected non-hydrocarbon gases, etc., which reduce the efficiency of their application.

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Therefore, the proposal of more efficient development methods is of particular relevance.

It was established in [1, 2, 17] that in the process of depletion of gas condensate deposits under the action of capillary and gravitational forces, redistribution of the fallen condensate occurs in the productive strata, and as a result, man-made condensate rims are formed near the gas-water contact, and the use of horizontal wells is recommended as a secondary method extraction of retrograde condensate from a man-made condensate rim.

Mathematical modeling of this problem is partially formulated and studied in [1, 2, 17, 18-21], and modeling of the solution of this problem, taking into account the use of horizontal wells, is not considered in these works. Therefore, the development of the stated ideas and the theoretical study of the process of segregation separation of hydrocarbon phases in depletion mode and the extraction of retrograde condensate from depleted gas condensate deposits seem to be an important and urgent task.

A rigorous solution to this problem requires the study of the following two problems:

1. Statement of the problem of segregation separation of hydrocarbon phases in depletion mode

To study the segregation separation of hydrocarbon phases during the depletion of gas condensate deposits under the action of capillary and gravitational forces, it is proposed to use a three-dimensional three-phase filtration model, which is a special case of the filtration model of multicomponent mixtures. In this case, the entire three-phase mixture is divided into three conventional components - gas ($C_{1\text{-}4}$), condensate (C_{5+}) and water (H_2O), all of which is in three phases under reservoir conditions.

The isothermal flow of three-phase filtration in a porous medium is described by the following system of differential equations obtained by combining the continuity equation for each three phases and the generalized Darcy law, using the assumption of local thermodynamic equilibrium of the phases [4]:

$$div\left[k\left(\frac{f_w(s_w)}{\mu_w(p)}c_w^i\rho_w(gradp_w-\gamma_w gradH)+\frac{f_l(s_l)}{\mu_l(p)}\rho_l c_l^i\times\right.\right.$$
$$\left.\left.\times(gradp_l-\gamma_l gradH)+\frac{f_g(s_g)}{\mu_g(p)}\rho_g c_g^i(gradp_g-\gamma_g gradH)\right)\right]=$$
$$=\frac{\partial}{\partial t}\left[m\left(\rho_w c_w^i s_w+\rho_l c_l^i s_l+\rho_g c_g^i s_g\right)\right]+$$
$$+\sum_{\nu=1}^{s}Q_\nu^i(t)\delta(x-x_\nu,y-y_\nu,z-z_\nu),\ i=1,2,3 \qquad (1)$$

$$\sum_{i=1}^{3}c_w^i=\sum_{i=1}^{3}c_l^i=\sum_{i=1}^{3}c_g^i=1,\ s_g+s_l+s_w=1,$$
$$i=1,2,3,\quad (x,y,z)\in D,\quad t\in(0,\overline{T}), \qquad (2)$$

where ρ_w, ρ_l, ρ_g are the densities of the water, liquid (condensate) and gas phases, respectively; c_w^i, c_l^i, c_g^i are the share of the$i$-th component in the water, liquid (condensate) and gas phases, respectively; γ_w, γ_l, γ_g - specific gravity of the water, liquid (condensate) and gas phases, respectively; m - porosity; k - absolute permeability; s_w, s_l, s_g - saturation with water, liquid (condensate) and gas phases, respectively; $f_w(s_w)$, $f_l(s_l)$, $f_g(s_g)$ - relative phase permeability of the water, liquid (condensate) and gas phases, respectively; μ_w, μ_l, μ_g - viscosity of the water, liquid (condensate) and gas phases, respectively; p_w, p_l, p_g - pressure in the water, liquid (condensate) and gas phases, respectively; $Q_\nu^i(t)$ - mass density of the i-th component; s - number of wells; $\delta(\cdot)$ - Dirac function; x_ν, y_ν, z_ν, - well coordinates along the axes, respectively; D - filtration area; H - hypsometry; $\overline{T}$ - development time; t - time.

Capillary forces are taken into account, and the relationship between the pressures in the phases is expressed through the capillary pressures at the hydrocarbon liquid-gas and water-gas interfaces:

$$p_w=p_g-p_{clg}\qquad p_w=p_g-p_{cwg},$$

where p_{clg} (p_{cwg}) is the capillary pressure at the condensate-gas (water-gas) contact.

The system of equations is closed by the initial and boundary conditions:

$$p_g(x,y,z,t)\big|_{t=0}=p_{g0}(x,y,z),$$
$$s_g(x,y,z,t)\big|_{t=0}=s_{g0}(x,y,z),$$
$$s_w(x,y,z,t)\big|_{t=0}=s_{b.w}(x,y,z),\ (x,y,z)\in D, \qquad (3)$$

$$\left.\frac{\partial p_g}{\partial n}\right|_{\Omega}=0,\ (x,y,z)\in\Omega, \qquad (4)$$

where $s_{b.w}$ is bound water; Ω - border of the filtration area; n - exterior normal to the boundary.

The unknowns in the system of equations (1)-(4) are gas and water saturation and p_g pressure. Excluding pressure in the water p_w and liquid p_l phases from (1)-(4), we obtain a problem for p_g, s_g, s_w:

$$div\left\{\left[k\left(\frac{f_w(s_w)}{\mu_w(p)}\rho_w c_w^i+\frac{f_l(s_l)}{\mu_l(p)}\rho_l c_l^i+\frac{f_g(s_g)}{\mu_g(p)}\rho_g c_g^i\right)gradp_g-\right.\right.$$
$$-k\left(\frac{f_w(s_w)}{\mu_w(p)}\rho_w c_w^i\gamma_w gradH+\frac{f_l(s_l)}{\mu_l(p)}\rho_l c_l^i\gamma_l gradH+\right.$$
$$\left.+\frac{f_g(s_g)}{\mu_g(p)}\rho_g c_g^i\gamma_g gradH\right)-$$
$$\left.\left.-\left(\frac{f_l(s_l)}{\mu_l(p)}\rho_l c_l^i gradp_{clg}+\frac{f_w(s_w)}{\mu_w(p)}\rho_w c_w^i gradp_{clw}\right)\right]\right\}=$$
$$=\frac{\partial}{\partial t}\left[m\left(\rho_w c_w^i s_w+\rho_l c_l^i s_l+\rho_g c_g^i s_g\right)\right]+$$
$$+\sum_{\nu=1}^{s}Q_\nu^i(t)\delta(x-x_\nu,y-y_\nu,z-z_\nu),\ i=1,2,3, \qquad (5)$$

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$$s_l = 1 - s_w - s_g,\ \sum_{i=1}^{3} c_w^i = \sum_{i=1}^{3} c_l^i = \sum_{i=1}^{3} c_g^i = 1,$$
$$(x,y,z) \in D,\ t \in (0,T), \quad (6)$$

$$p_g(x,y,z,t)\big|_{t=0} = p_{g0}(x,y,z),$$
$$s_g(x,y,z,t)\big|_{t=0} = s_{g0}(x,y,z),$$
$$s_w(x,y,z,t)\big|_{t=0} = s_{b.w}(x,y,z),\ (x,y,z) \in D, \quad (7)$$

$$\left.\frac{\partial p_g}{\partial n}\right|_{\Omega} = 0. \quad (8)$$

When the condition for the existence of local thermodynamic equilibrium is closed, the system of equations (5) is closed by the following relations:

$$\rho_w = \rho_w\left(p,T,c^1,c^2,c^3\right),\ \rho_l = \rho_l\left(p,T,c^1,c^2,c^3\right),$$
$$\rho_g = \rho_g\left(p,T,c^1,c^2,c^3\right),\ \mu_w = \mu_w\left(p,T,c^1,c^2,c^3\right),$$
$$\mu_l = \mu_l\left(p,T,c^1,c^2,c^3\right),\ \mu_g = \mu_g\left(p,T,c^1,c^2,c^3\right),$$
$$\rho = \rho\left(p,T,c^1,c^2,c^3\right). \quad (9)$$

The properties of the gaseous, liquid and water phases (9), necessary when solving the system of equations (5)-(8), are determined from the following system of equations:

$$\begin{cases} f_g^i - f_l^i = 0, \quad i = \overline{1,3} \\ f_g^i - f_w^i = 0, \quad i = \overline{1,3} \\ c_l^i F_l + c_g^i F_g + c_w^i F_w - c^i = 0, \quad i = \overline{1,3} \\ F_l + F_g + F_w = 1 \end{cases} \quad (10)$$

where F_l, F_g, F_w are the molar fraction of water, gas and liquid phases in the mixture; c^i - share of the i-th component in the mixture.

In system (10), the first and second equations describe the conditions of thermodynamic equilibrium - the equality of the volatilities of the components in the coexisting gas and liquid, water and gas phases, respectively, and the third and fourth equations - the distribution of mixture components between phases and the material balance equation for phases of the system, respectively.

Using the initial data of pressure p, temperature T and the component composition of the mixture c^i $(i = \overline{1,3})$ from the system of equations (11) it is possible to determine the mole fractions F_l, F_g, F_w and the compositions of the vapor liquid and water phases into which the initial mixture is divided under given thermobaric conditions [4, 7, 22]. In this case, the volatility of components in the gas and liquid, water and gas phases is calculated on the basis of known thermodynamic relationships using equations of state of the phases [23, 24].

Based on the described algorithm, technological calculations of the indicators of a specific gas condensate deposit in the depletion mode are carried out (fig. 1).

The deposit area is approximately 6.25 km². The initial reservoir pressure is 45 MPa. The reservoir temperature was 102 °C, the condensation pressure of the reservoir hydrocarbon mixture was approximately 38.5 MPa. The density of the liquid phase of the deposit is 0.8 t/m³, molecular weight is 160, the condensate content of the gas phase is 362 g/m³. The reservoir porosity is 16.9% and the permeability is 0.042 μm. The thickness of the formation is approximately 200 m.

The reservoir gas-condensate mixture was characterized by the following initial average composition (molar fraction, %): methane - 88.59; ethane - 4.11; propane - 1.47; butane - 0.77; pentane plus high-boiling hydrocarbons - 4.86; carbon dioxide - 0.2;

According to the results of mathematical modeling of the process of differential condensation under given thermo-baric conditions, the current values of the coefficients of gas, condensate and water saturation are respectively equal to s_g=0.84, s_c=0.04, s_w=0.12 and these values of fluid saturation are taken as initial values when carrying out calculations.

The deposit is discovered by five production wells, in which parts were perforated, revealing the upper half of the productive strata and the flow rate of production wells is 5% of current reserves.

The necessary physical properties of fluids saturating the formation, including the density and viscosity of gas, condensate and water, are obtained by calculating the vapor-liquid state from three-phase filtration based on (10) and they are presented in figures 2 and 3.

The relative phase permeability of gas and condensate are obtained during the adaptation of the hydro-

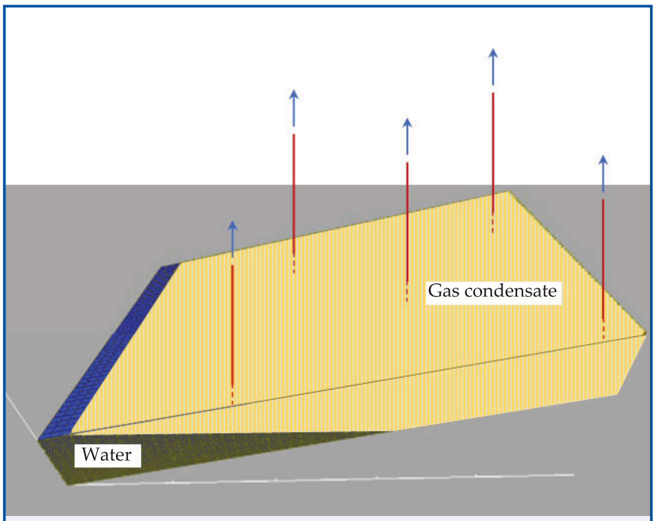

Fig. 1. The reservoir model

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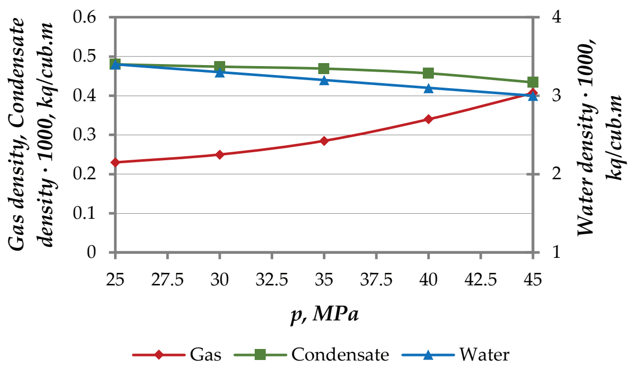

Fig. 2. Dependence of density of gas, condensate and water from pressure

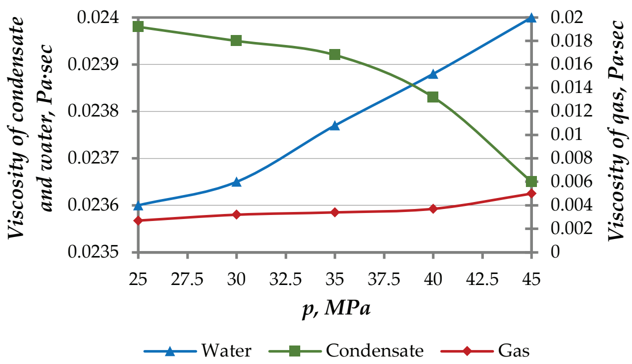

Fig. 3. Dependence of dynamic viscosity of gas, condensate and water pressure

dynamic model according to the development history of this reservoir:

$$f_g\left(s_g\right)=\left(\frac{s_g-0.1}{0.9}\right)^{3.5},$$

$$s_g \geq 0.1,\ f_l\left(s_g, s_w\right)=\left(\frac{s_g+s_w-0.15}{0.85}\right)^{2.8},\ 0.15 \leq s_g+s_w$$

$$f_w\left(s_w\right)=\frac{s_w-0.2}{0.8},\ s_w \geq 0.2.$$

The capillary pressures at the hydrocarbon liquid-gas and water-gas interfaces are taken as follows:

$$p_{clg}(s_l)=\Pi \cdot J(s_l);\quad J(s_l)=\frac{0.2(0.9-s_l)}{(1.2-s_l)^2(2s_l-s_l^2)};$$

$$(l=l,w)\ \Pi=10^5\,Pa$$

According to gas-hydrodynamic calculations, the reservoir depletion regime will last for 20 years. During this period, 84% of the initial gas reserves and 27.2% of the initial condensate reserves were produced from the reservoir model. During the specified development period, reservoir pressure decreased from 45 MPa to 3.9 MPa (fig. 4). The process of gravitational separation begins quite quickly; already 7 years after the start of development, the vertical distribution of condensate saturation increases noticeably with depth. In the bottom layer of the deposit it is distributed evenly. At the end of the 20th year of development, the thickness of the condensate rim of retrograde condensate is approximately 24 m and it constitutes 12% of the total gas content with an average condensate saturation of about 0.44 (fig. 5).

Thus, the studies carried out on mathematical models have established that the possibility of segregation processes occurring during the depletion of gas condensate deposits, which lead to the formation of a technogenic condensate rim near the gas-water contact.

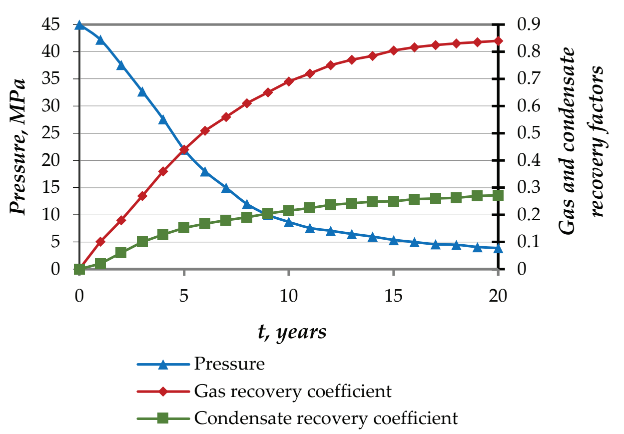

Fig. 4. Dependence of gas and condensate recovery coefficient and reservoir pressure from development time

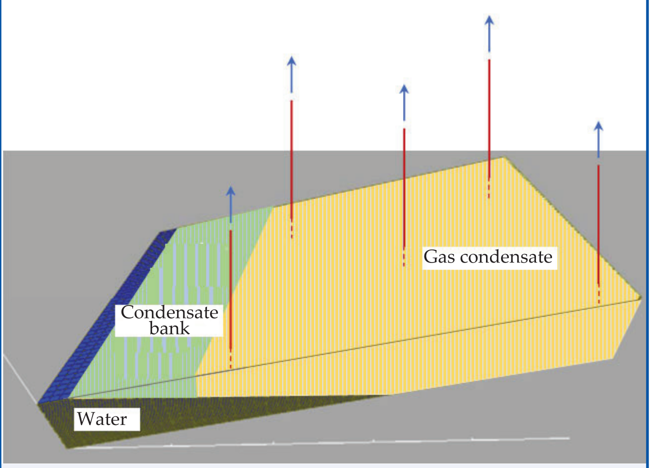

Fig. 5. Character of fluid saturation in the 20-th year reservoir in depletion mode

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2. The statement of the problem of extracting retrograde condensate from depleted gas condensate deposits

According to the results of the segregation separation of hydrocarbon phases in the depletion mode, the assessment of the possibility of the formation of technogenic rims of retrograde condensate with small thicknesses of gas content suggests secondary condensate production.

It is advisable to extract retrograde condensate from a relatively thin condensate rim, as a secondary method, using horizontal wells drilled in this rim [3]. In this case, water exposure was chosen. Water injection is done by wells, which were producing in the depletion mode of the deposit. The volume of the injection is such that the injection pressure does not exceed hydrostatic pressure and the period of exposure is determined by the water cut of the product, which should be 98%.

To solve the formulated problem, the system of equations (5)-(11) is also supplemented with a system of equations that describes the flow of fluids in a horizontal wellbore under the appropriate initial and boundary conditions [10, 25]:

$$div\left(\rho_m z_m^k \vartheta_m\right)+\frac{\partial}{\partial t}\left(\rho_m z_m^k\right)=0, \sum_{k=1}^{3} z_m^k(x,y,z,t)=1,$$
$$(x,y,z)\in D, t>T, \quad (12)$$

$$z_m^k(x,y,z,t)\Big|_{t=T}=z_{m0}^k, \quad (13)$$

$$2\pi r_w \int_0^{z_{\max}} z_m^k \vartheta_m(x,y,z,t)\Big|_{r=r_w} dz = Q^k(t),$$
$$\sum_{k=1}^{3} Q^k(t)=Q_0(t) \quad (14)$$

where the index m corresponds to the well mixture; z_m^k – mass fraction of the component k in the mixture; ρ_m, $\rho\vartheta_m$ – density and flow rate of the mixture in the barrel, respectively; r_w – radius of the horizontal well; $Q^k(t)$ – flow rates of mixture components; $Q_o(t)$ – flow rate of a horizontal well; $z_{\max}$ – length of the horizontal part of the well.

Two injection options are considered and they differ in the arrangement of the perforation intervals.

Option I: The wells penetrate the upper part of the productive strata and condensate is not collected from the rim for three years. A production delay is required for the impact to reach the condensate rim.

Using the necessary initial data r_w=0.1 m, $z\in[0.500\,\text{m}]$, $Q_o(t)$=17·10^5 m^3/day, $z_m^1=0$, $z_m^2=1$, $z_m^3=0$, gas-hydrodynamic calculations were carried out.

In the first option, during the process of flooding and extraction of retrograde condensate, it was discovered that with increasing pressure and dissolution of the light fraction in the hydrocarbon mixture, condensate saturation relatively increases. Under the influence of gravitational forces, a condensate pillar is formed, i.e. the liquid hydrocarbon phase floats up. The accumulated recovery of gas and condensate is respectively – $25.7\cdot10^9$ м^3 and $29.5\cdot10^6$ м^3 tons, respectively, additional production – $0.5\cdot10^9$ м^3 and $10.6\cdot10^6$ м^3 tons, gas recovery factor – 0.853, condensate recovery factor – 0.42. During the considered period of reservoir development, about 96.8 million m^3 of water will be pumped into the reservoir.

In the second option, a significant amount of water enters the overlying layers, and the rise of condensate occurs more intensely. After analyzing the dynamics of the main development indicators, the process efficiency is low compared to the first option. To complete development process, the accumulated gas and condensate recovery is approximately $25.4\cdot10^9$ м^3 and $28.3\cdot10^6$ tons, additional production – $0.2\cdot10^9$ м^3 and $9.4\cdot10^6$ tons, gas recovery rate – 0.846, condensate recovery rate – 0.404. To implement this option, it will be injected into the reservoir about $69.7 million м^3 of water.

Comparison of additional condensate production according to the options is presented in figure 6.

Thus, based on mathematical modeling, it is shown that from the technogenic condensate rims formed in the gas-water contact under the influence of gravitational forces on depleted gas condensate deposits, It is possible to extract retrograde condensate by horizontal wells drilled in this rim using water injection into the formation, which is a fairly effective way of developing compared to traditional secondary methods for extracting retrograde condensate [5].

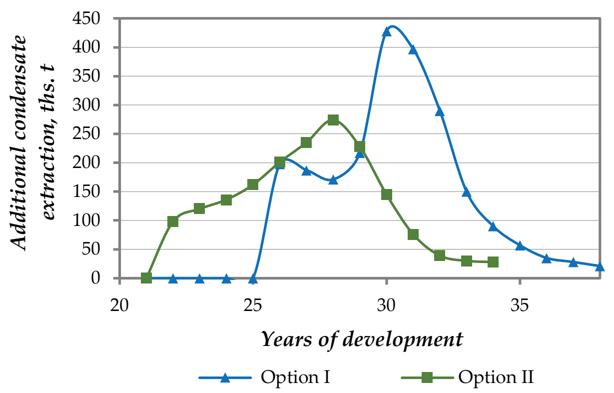

Fig. 6. Comparison of additional condensate production according to options for vertical flooding

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Conclusions

1. Based on a three-phase three-component model of fluid filtration in a reservoir-well system, the process of segregation separation of hydrocarbon phases in depletion mode and the extraction of retrograde condensate from depleted gas condensate deposits were modeled.
2. It has been established that the manifestation of segregation processes during the depletion of gas condensate deposits leads to the formation of a technogenic condensate rim near the gas-water contact, and flooding is an effective way to develop technogenic condensate rims.
3. The greatest effect in terms of final condensate recovery during flooding is achieved when water is injected at the crest of the reservoir.

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