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Evaluation of the gas recycling duration on the hydrocarbon recovery from gas condensate fields

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ABSTRACT

Purpose: Optimization of formation pressure maintenance technologies in the development of gas condensate fields with a high initial content of condensate in the reservoir gas using numerical modelling.

Design/methodology/approach: A study on the efficiency of dry gas injection for pressure maintenance in gas condensate fields was performed with the help of numerical 3D models. Key technological indicators of the reservoir development were calculated for the dry gas injection period of 12, 24, 36, 48, and 60 months. The results are presented as plots for the parameters in a study.

Findings: Based on the results of the studies, it was found that the introduction of dry gas injection technology ensures that reservoir pressure is maintained at the highest level compared to the development of gas condensate reservoirs on primary depletion. Due to this, further condensate drop-out in the reservoir is slowed down, and the production of partly already condensed hydrocarbons is ensured by their evaporation into the dry gas injected from the surface. The simulation results indicate that increase in the injection duration period leads to an increase of the cumulative condensate production and hence the final hydrocarbon recovery factor.

Research limitations/implications: The heterogeneity of oil and gas deposits, both in terms of area and thickness, significantly affects the efficiency of the developed hydrocarbon enhancement technologies. In order to minimize the negative impact of heterogeneity, it is necessary to conduct additional studies on the conditions of specific reservoirs or fields.

Practical implications: The reservoir pressure maintenance technology implementation according to various technological schemes, as well as using various types of injection agents, will significantly intensify the development of depleted gas condensate fields with a high condensate yield.

Originality/value: Statistical analysis of the simulation results identified the optimum value of the dry gas injection period into the gas condensate reservoir, which is 34.3 months for the conditions of a given reservoir in the study.

Keywords: Gas condensate reservoir, Condensation of heavy hydrocarbons, Hydrocarbon recovery enhancement technologies, Cycling process, Dry gas injection period

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METHODOLOGY OF RESEARCH, ANALYSIS AND MODELLING

1. Introduction

Natural gas fields' development planning should be based on a deep understanding of the processes occurring in the porous media, namely, multiphase flow and phase transitions of multicomponent hydrocarbon systems [1-3].

When developing gas condensate fields, special attention should be made to particular features associated with the condensation of heavy hydrocarbons when the reservoir pressure drops below the dew point. The essence of this phenomenon is the separation of reservoir gas into two phases, gas and liquid condensate [4].

Saturation of the porous media with a liquid hydrocarbon phase causes additional hydrocarbon losses during the field development. This, in turn, can be explained by the interfacial properties of the liquid phase in relation to the porous media, i.e. saturation of the pore space with the liquid phase to a certain critical value causes its loss. This is the reason for the relatively low condensate recovery from gas condensate reservoirs with a high potential yield of condensate in the reservoir gas [5].

The ultimate condensate recovery factor in the development of gas condensate fields in the depletion mode is 13-40% [5,6].

In order to increase the ultimate condensate recovery factors and improve the technical and economic indicators of the development of gas condensate fields, reservoir pressure maintenance technologies must be implemented.

Reservoir pressure can be maintained by reverse injection of separated (dry gas), use of dry gas from neighbouring oil and gas fields, non-hydrocarbon gases (nitrogen, carbon dioxide, air, flue and exhaust gases), a mixture of hydrocarbon and non-hydrocarbon gases, water injection and gas-water mixtures [7-9].

In industrial practice, a full or partial cycling process is mainly used with the injection of all or part of the separated dry gas into the reservoir.

2. Literature review

Following the industrial experience in developing oil and gas fields, as well as active scientific research, a significant number of technologies and methods for the production of condensed hydrocarbons have been developed, the results of which are reflected in [10-12].

The impact of precipitated condensate in porous media on flow resistance coefficients was studied in [13]. A reservoir model was created, a gas condensate mixture was flowing through it, changing the radius of the two-phase flow region zone. As a result of the research, it was found that coefficient A practically does not depend on the amount of condensate but varies depending on the radius of the two-phase mixture flow zone. The coefficient B depends both on the amount of condensate and on the filtration radius of the two-phase mixture. Binomial inflow performance into a vertical gas well:

$$P_f^2 - P_{bh}^2 = Aq + Bq^2 \tag{1}$$

where A and B – flow resistance factors:

$$A = \frac{\mu \, ln\frac{R_c}{r_w}}{2\pi kh} = \frac{1}{K_0}; \qquad B = \frac{\rho\left(\frac{1}{r_w} - \frac{1}{R_c}\right)}{(2\pi h)^2 l'} \tag{2}$$

Another important step in predicting the condensate flow and accumulation in the near-wellbore zone is the modelling of gas condensate systems. In [14], based on the field study results, a method for calculating the mole fraction of an individual component in the reservoir mixture was developed. Using the developed technique, it is possible to define the ratio between liquid and gaseous phases and their flow to the bottom of the well.

An increase in the hydrocarbon recovery of gas condensate fields is possible through the introduction of secondary recovery technologies, which include rational technologies of artificial influence on a productive reservoir using external energy [15,16].

The production of condensate precipitated from the gas in the reservoir can be carried out by transferring it to the gas phase with subsequent associated production with gas, displacement from the porous medium by various working agents and their combination [17-19].

The cycling process and other reservoir pressure maintenance technologies are the most well-known technologies for developing gas condensate fields, which provide significantly higher ultimate condensate recovery factors compared to primary depletion development [20,21].

The cycling process and its modifications are the reinjection of stripped gas into a gas condensate reservoir, which is characterized by a high yield of condensate in the reservoir gas. The physical essence of the process is the ability of dry gas to evaporate condensed liquid hydrocarbons. After separation and purification of the producing gas, it is re-injected into the reservoir. The efficiency of the cycling process and the size of the injection slug are studied on core material, as well as in PVT installations [22,23].

To implement the technology of reservoir pressure maintenance using dry gas, it is necessary to introduce an optimal system for the placement of production and injection wells. When developing reservoirs of anticline type, it is recommended to place injection wells in the central part, and production wells in the periphery. However, this is possible in the absence of active aquifer drive in order to prevent premature watering of the wells. In giant fields with large reserves, wells are often placed in lines, and the distance between the lines is set based on the reservoir properties.

In the case of gas cycling process, rather high values of the condensate recovery factor are achieved, with ultimate recovery factors reaching 70–90 % [24]. This method, despite its high technological efficiency, has some disadvantages. The main disadvantage is the significant capital investment, a long development period, conservation of natural gas reserves during the period of technology implementation. As an alternative, partial gas re-cycling recommended. When pumping 40-60% of the separated gas, the final condensate recovery factor can vary from 50 to 70% and will depend on the time of when gas re-injection is implemented.

In the Ukrainian fields, the cycling process was implemented in the reservoirs of the T-1 of the Kulychykhinske and Tymofiivske fields, C-5 reservoir of the Kotelevske field, K-30 reservoir of the Novotroitske field. In the Berezivske field, in order to increase the ultimate hydrocarbon recovery of the C-5 reservoir, the downhole gas bypass was carried out from the V-16 gas reservoir, which was characterized by a low potential condensate yield [25].

Commercial field experience in oil and gas fields development with high initial condensate yield indicates that the proposed methods and technologies are characterized by both advantages and significant disadvantages. Most of them have significant technological limitations, which are limiting their active wide full-field implementation.

Also, to increase the ultimate hydrocarbon recovery, the number of combined methods exist based on the sequential or simultaneous injection of certain displacing agents. The feasibility of using each of these methods depends on the geological and technological conditions of a particular field and the quality of initial data [26-28].

It should also be noted that in the case of the implementation of one or another method for improvement of the ultimate hydrocarbon recovery during the production operations from the gas condensate wells, a multiphase mixture is transported to the surface, that enters surface flowlines and causes complications in the operation of the gas collection system and surface facilities. The composition of the multicomponent mixture includes formation and condensed water, hydrocarbon condensate, mechanical impurities, salts, methanol, etc. This leads to a decrease in the productivity of producing wells and may cause the cessation of natural lift [29].

The main problems that complicate the movement of gas through the surface flowlines are the accumulation of liquid in down dips and formation of hydrates. Down dip parts of the flowlines due to uneven terrain and the passage through open water ponds, lakes and rivers cause additional pressure losses in the flowlines. Thus, to increase the efficiency of the residual hydrocarbon reserves recovery, periodic cleaning of flowlines and pipelines is necessary. At present, a significant number of both theoretical and experimental studies have been carried out, on the basis of which effective technologies and methods for cleaning the internal cavity of pipelines have been developed [30,31].

Additional complications in the production of hydrocarbons may be associated with corrosion of equipment, as well as the blockage of pipelines. Corrosion occurs due to the presence of moisture in the carbon dioxide stream. When carbon dioxide reacts with water, carbonate acid is formed, which causes an aggressive corrosive environment. Therefore, pipelines and plumes with a significant content of carbon dioxide in the reservoir gas must be made of a corrosion-resistant alloy or have an inside alloy coating [32,33].

Given the above, there is a need for additional research to improve the existing technologies and develop new technologies that will give improved technical and economic indicators of oil and gas field development.

3. Methods and materials

The objective of this study is to improve reservoir pressure maintenance technologies for the development of gas condensate fields with high initial condensate yield in the reservoir gas using numerical simulation tools. Based on the results of the studies, provide recommendations for the optimization gas condensate fields' development by substantiating the optimal development option that provides maximum hydrocarbon recovery factors at minimal cost.

To achieve the goals set, the following tasks have to be solved:

1. Investigate the effect of the dry gas injection period duration on the technological parameters of the gas condensate reservoir development with a high initial condensate yield in the reservoir gas.
2. Find the optimal duration of the cycling process implementation for the development of gas condensate deposits with high initial condensate yield in the formation gas.

The study of the cycling process was carried out using a heterogeneous numerical 3D model of a gas condensate reservoir with the following parameters: reservoir thickness – 15 m, average porosity – 0.11, initial gas saturation – 0.8, average absolute reservoir permeability – 7.24 mD, the average depth of the producing reservoir – 4500 m, the initial reservoir pressure – 45 MPa, the reservoir temperature – 393 K. Gas initially in place is 2291 mln.m^3, and condensate in-place volume is 0.863 mln.m^3. The initial content of liquid hydrocarbons of C_{5+} fraction in reservoir gas is 330 g/cm^3.

The change in the potential yield of the C_{5+} fraction in the reservoir gas is shown in Figure 1.

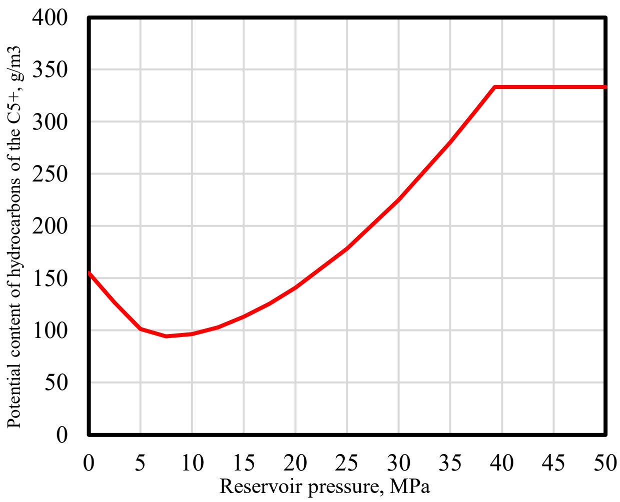

Fig. 1. Potential yield of the C_{5+} fraction in the reservoir gas

The gas condensate reservoir is being developed using seven wells operated at a constant flow rate of 80 th.m^3/day. There are three injection wells in the central part of the reservoir operating with injection rates of 186 th.m^3/day. The displacement ratio of dry gas injection rate to hydrocarbon production is 100%.

A conceptual model of a gas condensate reservoir with porosity distribution in a heterogeneous 3D model is shown in Figure 2.

The study was performed for different durations of the dry gas injection into the gas condensate reservoir: 12, 24, 36, 48, and 60 months. After reaching the predetermined duration of the dry gas injection period, the injection wells were stopped, and further operation of the production wells continued until the end of the gas condensate reservoir development. The implementation of the cycling process is carried out when the gas condensate reservoir is depleted to 50% of the initial reservoir pressure.

For a proper accounting of the complex phase behaviour processes that take place during dry gas injection into a gas condensate reservoir, a compositional PVT model was created [34,35].

Based on the performed studies, the calculation of technological indicators for the development of a gas condensate reservoir with a high condensate yield in the reservoir gas was carried out. Graphical analysis and processing of the study results were performed for the end period of the reservoir development using statistical methods to determine optimum cases.

Statistical analysis (intersection of tangents) [36,37] was used to treat the graphical dependences in order to determine the optimal points of the parameters studied.

According to the statistical analysis, the $f(x)=a_0+a_1x$ function values are selected so that the deviation of the studied points $(x_i;\ y_i)$ $i=\overline{1..N}$ from the selected curve is minimal. The parameters a_0, *and* a_1 must be such that the sum of squares of the deviations of observed values y_i from those calculated for the $f(x)=a_0+a_1x$ function is minimal. After certain transformations, a system of two linear equations is received for the unknown regression parameters.

$$\begin{cases} \min\limits_{v,a_v}\left\{\sigma_{av}^2=\frac{1}{n_v-r_v}\sum_{i=1}^{n_v}[f_v(a_v,x_i)-y_i]2\right\}\Rightarrow\left\{\hat{v},\hat{a}_v\right\} \\ \min\limits_{\varepsilon,a_\varepsilon}\left\{\sigma_{a\varepsilon}^2=\frac{1}{n_\varepsilon-r_\varepsilon}\sum_{i=1}^{n_\varepsilon}[f_\varepsilon(a_\varepsilon,x_i)-y_i]2\right\}\Rightarrow\left\{\hat{\varepsilon},\hat{a}_\varepsilon\right\} \end{cases} \quad (3)$$

$$f_v\left(\hat{a}_v,x_*\right)-f_\varepsilon\left(\hat{a}_\varepsilon,x_*\right)=0\Rightarrow x_* \quad (4)$$

$\sigma_{av}^2,\sigma_{a\varepsilon}^2-$ is the variance assessment of the f_v and$f_\varepsilon$effectiveness; r_v,r_ε is the number of the evaluated parameters of models $f_v(a_v,x_i)$ and$f_\varepsilon(a_\varepsilon,x_i)$.

The parameters a_0, a_1, a_2,…, a_n are determined by solving this system of equations. The parameters found are substituted in the equation $y=f(x)$: this technique produces linear equations that best describe the estimated data. After that, we build dependences for specific estimated data and approximate each of them by two straight lines, the point of intersection of which corresponds to the optimal value studied.

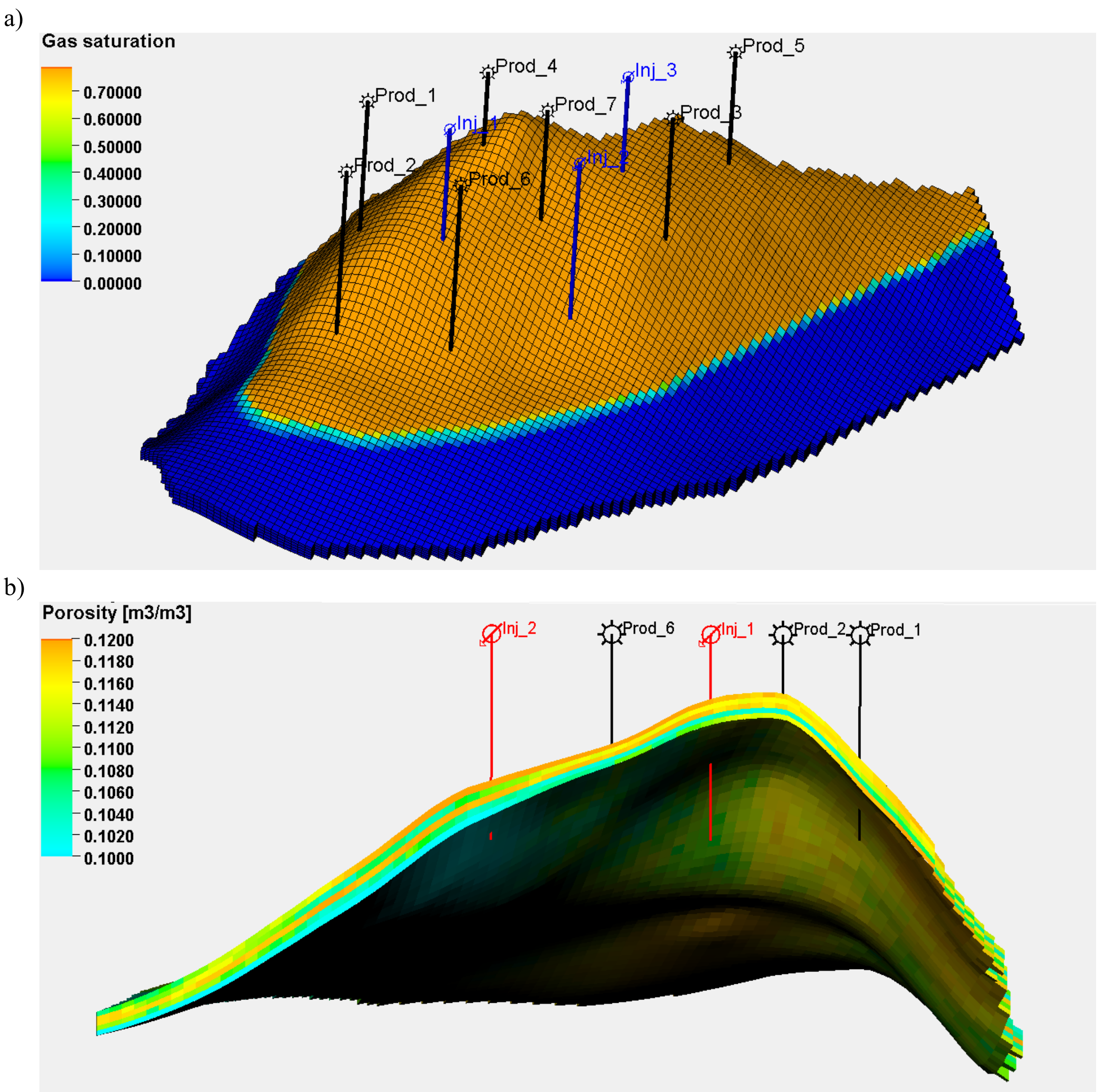

Fig. 2. Conceptual model of a gas condensate reservoir (a) and porosity distribution (b) in a heterogeneous 3D model

4. Study results on implementation of reservoir pressure maintenance technology in the development of gas condensate reservoirs

4.1. Influence of the dry gas injection period duration on the technological indicators of the development of a gas condensate reservoir

Implementation of the cycling process allows maintenance of the reservoir pressure in the gas condensate reservoir at a higher level compared to depletion development. Reservoir pressure change depending on the duration of the dry gas injection period into the gas condensate reservoir as well as during depletion development is shown in Figure 3.

Results analysis indicated that in the case of dry gas injection into the reservoir, stable operation of production wells is maintained. The longer the dry gas injection period, the longer the period of reservoir development. The provision of the necessary conditions explains the result to carry out liquid offloading (condensate, water) from the bottom of the wells to the surface by increasing the drawdown on the productive formations during the period of the cycling process. Thus, wells are operated at a constant flow rate for a longer period of development of a gas condensate reservoir.

Change of the gas flow rate from the duration of the dry gas injection period into the gas condensate reservoir and during the depletion development in Figure 4.

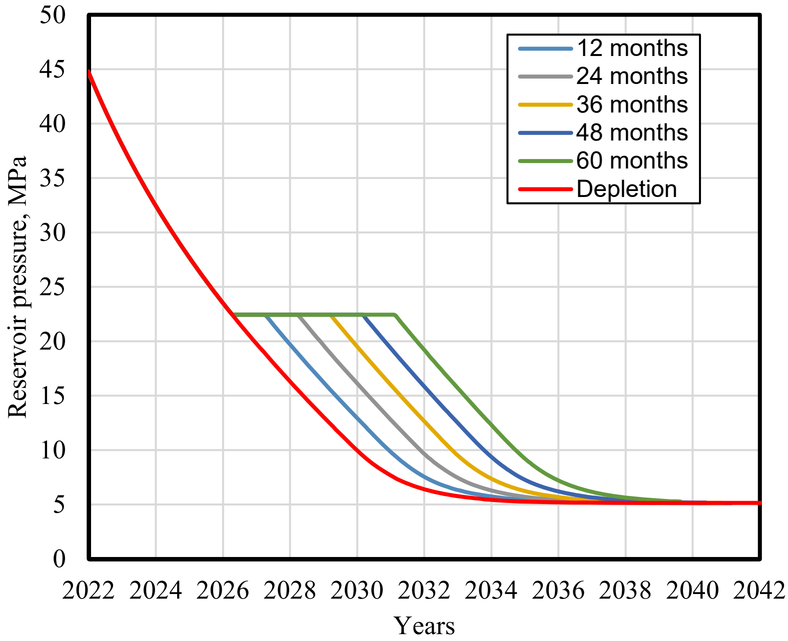

Fig. 3. Reservoir pressure change depending on the period of dry gas injection duration into the gas condensate reservoir and during depletion development

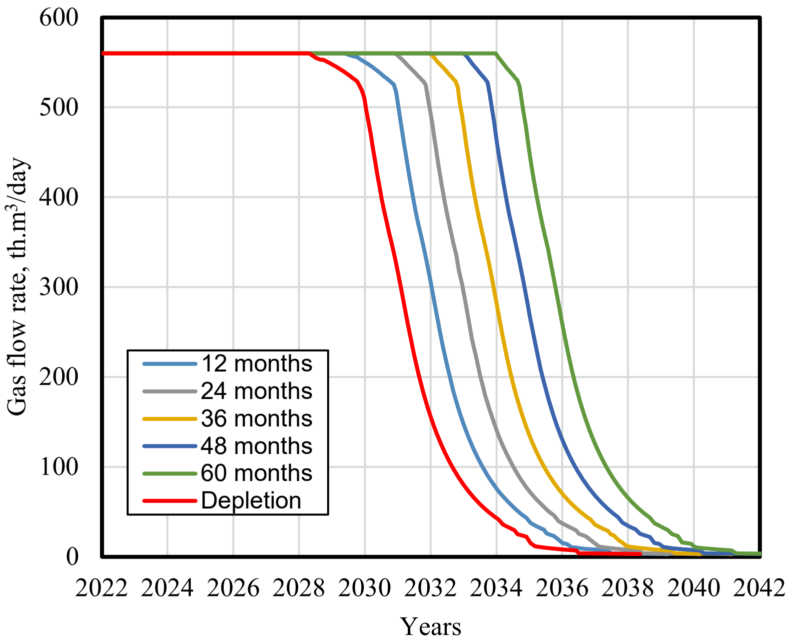

Fig. 4. Change of gas flow rate depending on the duration of dry gas injection period into the gas condensate reservoir and during depletion development

With the introduction of reservoir pressure maintenance technology, the process of further condensation of heavy hydrocarbons slowed down, and pressure increase created the conditions for the dissolution and evaporation of already precipitated condensate in the pore space with its subsequent production. This also resulted in the increased cumulative condensate production compared to depletion development.

Impact of dry gas injection duration on cumulative condensate production compared to depletion case is shown in Figure 5.

The cumulative condensate production is proportional to the duration of the dry gas injection period; the longer the injection – the higher production is 12 months – 349.7 th.m^3; 24 months – 366.7 th.m^3; 36 months – 377.4 th.m^3; 48 months – 383.6 th.m^3; 60 months – 387.6 th.m^3. Depletion development results in 324.8 th.m^3 of condensate produced.

The results of reservoir condensate production calculations depending on the duration of the reservoir pressure maintenance implementation period are shown in Table 1.

Increased condensate production well correlates with reduced liquid (condensate) saturation, shown in Figure 6, for the duration of dry gas injections 12, 36 and 60 months.

Numerical simulation results clearly indicate that the injection of dry gas primarily reduces the condensate saturation in the area around the injection wells. The longer the reservoir pressure maintenance period, the larger the area influenced by the dry gas injection agent.

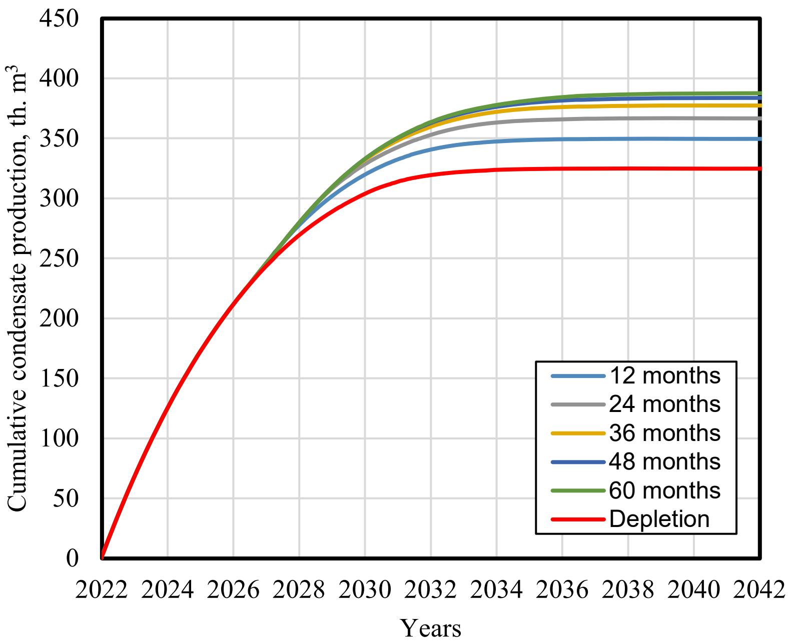

Fig. 5. Change of cumulative condensate production depending on the dry gas injection period injection into the gas condensate reservoir and during depletion development

Table 1.
Calculation results of reservoir condensate production depending on the duration of the period of implementation of reservoir pressure maintenance technology and for the depletion development of gas condensate reservoir

Dry gas injection period, months	Cumulative condensate production, th.m^3		Incremental condensate production, th.m^3	Dry gas injection, mln.m^3	Incremental specific condensate production, m^3/m^3
	Depletion case	Injection case			
12	324.90	349.69	24.79	196.22	126.36
24	324.90	366.79	41.89	392.99	106.59
36	324.90	377.42	52.52	589.21	89.14
48	324.90	383.66	58.76	785.43	74.81
60	324.90	387.57	62.67	981.66	63.84

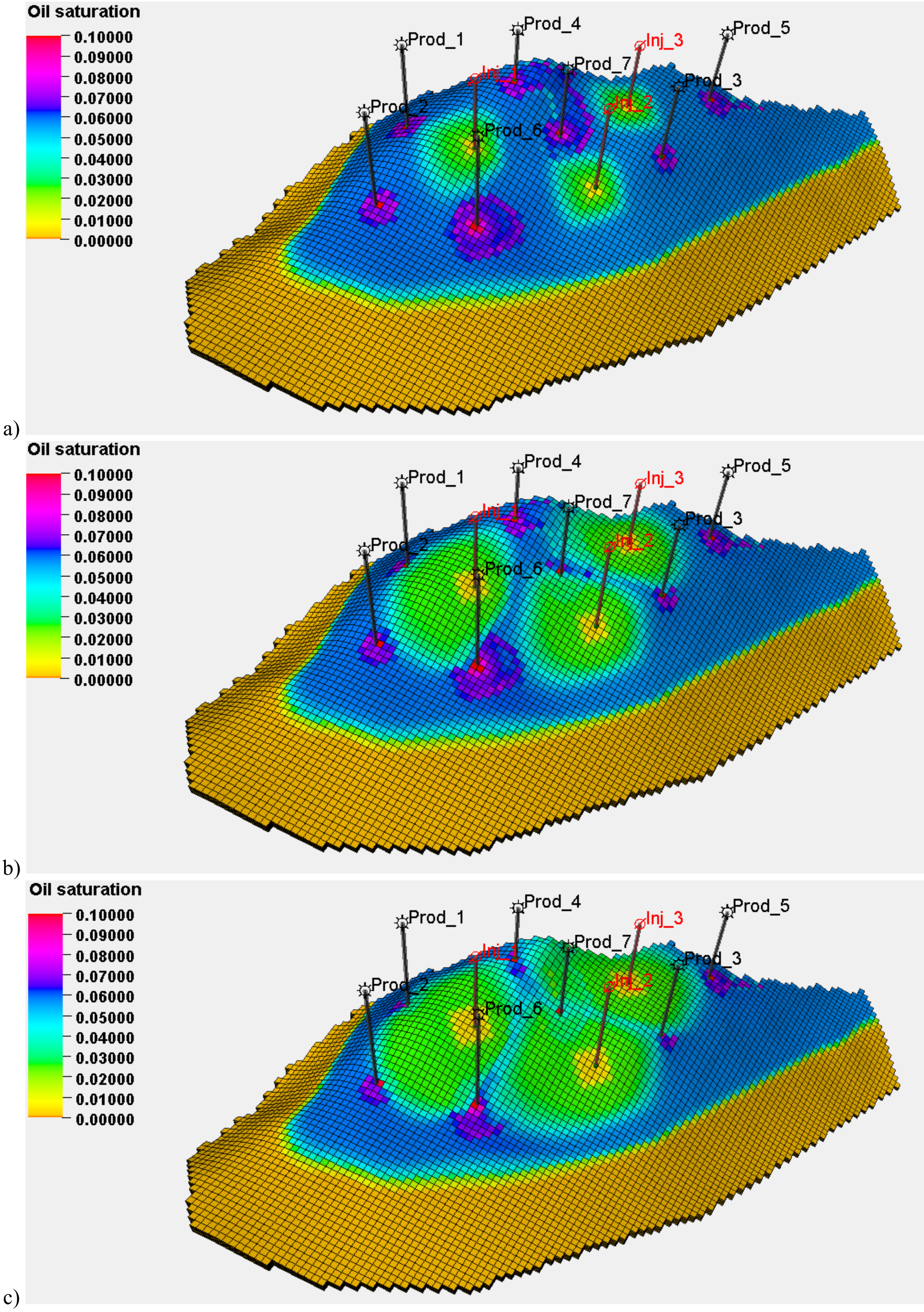

Fig. 6. Condensate saturation at the end of dry gas injection period of 12 months (a), 36 months (b) and 60 months (c)

Table 2.
Calculation results of reservoir gas production depending on the duration of the period of implementation of reservoir pressure maintenance technology and for the depletion development of gas condensate reservoir

Dry gas injection period, months	Depletion case, mln.m^3	Reservoir pressure maintenance			Incremental gas production, mln.m^3
		Reservoir gas production, mln.m^3	Dry gas production, mln.m^3	Total gas production, mln.m^3	
12	1984.33	1988.08	196.22	2184.30	3.75
24	1984.33	1991.13	392.99	2384.11	6.80
36	1984.33	1993.56	589.21	2582.77	9.24
48	1984.33	1995.75	785.43	2781.19	11.43
60	1984.33	1997.50	981.66	2979.16	13.17

Table 3.
Hydrocarbon recovery factors depending on the duration of the dry gas injection period and on the depletion development

Duration of the injection period, months	Condensate recovery factor, %			Gas recovery factor, %		
	Depletion	Injection	Δ	Depletion	Injection	Δ
12	37.64	40.51	2.79	86.62	86.78	0.16
24	37.64	42.49	4.61	86.62	86.91	0.30
36	37.64	43.72	5.76	86.62	87.02	0.40
48	37.64	44.45	6.49	86.62	87.12	0.50
60	37.64	44.90	7.09	86.62	87.19	0.58

According to the study results, the average saturation of precipitated condensate, depending on the duration of the dry gas injection period, is: 12 months – 2.86%; 36 months – 2.52%; 60 months – 2.28%. It should also be noted that due to the introduction of the cycling process in the development of a gas condensate reservoir with significant condensate reserves, incremental production of reservoir gas is also achieved.

The results of reservoir gas production calculations depending on the duration of the reservoir pressure maintenance implementation period are shown in Table 2.

The results of the studies testified the high technological efficiency of the reservoir pressure maintenance technologies with dry gas recycling in comparison to the primary depletion.

4.2. Definition of the optimal period for the implementation of the cycling process in the development of gas condensate reservoirs with high initial condensate yield in the reservoir gas

According to the results of the studies on increasing the ultimate hydrocarbon recovery from gas condensate fields with a high initial condensate yield, the prediction of hydrocarbon recovery factors was carried out.

The results of calculations of gas and condensate recovery factors depending on the duration of the dry gas injection period, together with the depletion development of the gas condensate reservoir, are shown in Table 3.

Analysing the results of calculations in Table 2 showed that the increase in the ultimate condensate recovery factor, depending on the duration of the dry gas injection period, is: 12 months – 2.79 %; 24 months – 4.61 %; 36 months – 5.76 %; 48 months – 6.49 %; 60 months – 7.09 %.

At the same time, the ultimate gas recovery factor, depending on the duration of the dry gas injection period, increases by: 12 months – 0.16%; 24 months – 0.30%; 36 months – 0.40%; 48 months – 0.50%; 60 months – 0.58%.

Dependences of the incremental gas and condensate recovery factors from the duration of the dry gas injection period are shown in Figures 7 and 8.

Based on the results of the statistical processing of calculated data, the optimal value of the duration of the period of dry gas injection into the gas condensate reservoir, beyond which the condensate recovery factor does not change, was determined. The optimal injection duration is 34.3 months. The ultimate condensate recovery factor for the given optimal value of the duration of the dry gas injection period is 43.7%.

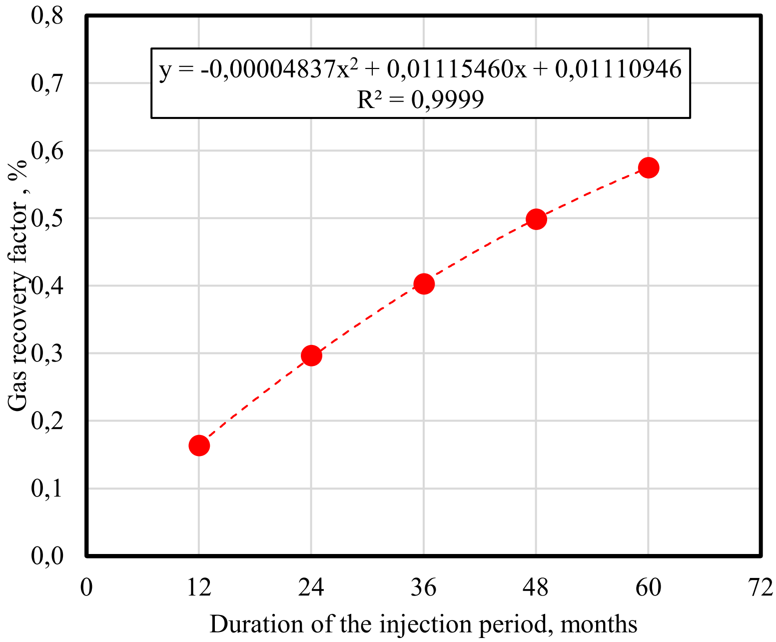

Fig. 7. Dependences of the increase in the gas recovery factor from the duration of the dry gas injection period

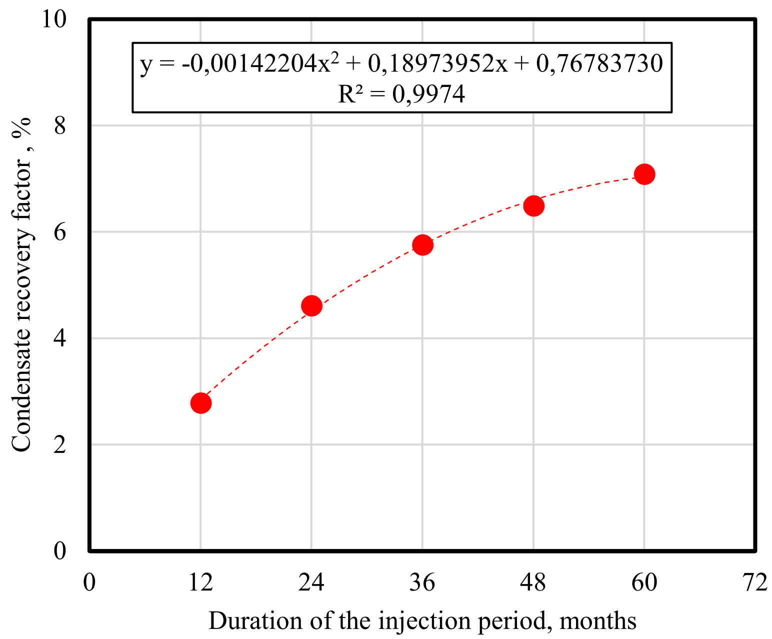

Fig. 8. Dependences of the increase in the condensate recovery factor on the duration of the dry gas injection period

5. Results and discussions

The simulation results indicate that the introduction of reservoir pressure maintenance technology for the development of gas condensate reservoirs helps to keep the reservoir pressure at a higher levels compared to depletion development (Fig. 3).

Also, when dry gas is injected into the gas condensate reservoir, stable operation of production wells is maintained, which leads to a longer development period of the gas condensate reservoir (Fig. 4).

Analysing the results of the conducted studies (Fig. 5), it should be noted that with an increase in the duration of the dry gas injection period, the absolute difference in the increase in cumulative condensate production between the calculated options decreases. With an increase in the duration of the injection period from 12 to 24 months, the increase in cumulative condensate production is 17.1 th.m^3, with an increase from 24 to 36 months – 10.6 th.m^3, from 36 to 48 months – 6.2 th.m^3, and from 48 to 60 months – 3.9 th.m^3.

Given the above, it should be noted that the largest increase in hydrocarbon production is achieved in the first few years. Therefore, the duration of the cycling process implementation period, taking into account its main drawback, namely, the conservation of reservoir gas reserves, should be determined individually, based on the results of technical and economic calculations.

Simulation results also showed that in the near wellbore zone of production wells, the condensate saturation is the highest. This is due to the existence of a zone with low reservoir pressure, which causes favourable conditions for the condensation of heavy hydrocarbons. With an increase in the distance from the bottomhole of production wells, the saturation of the pore space with precipitated condensate decreases. The highest condensate saturations are observed in the vicinity of production wells in depletion case (Fig. 6).

When implementing the gas cycling technology processes, the saturation with condensed hydrocarbons decreases, while additional production of gas and condensate is achieved (Fig. 8)

The results of the carried out studies proved high technological efficiency of dry gas cycling as reservoir pressure maintenance technology for the development of gas condensate reservoirs with a high content of liquid hydrocarbons.

6. Conclusions

1. Using numerical modelling tools, the effectiveness of implementing reservoir pressure maintenance technologies using dry gas in order to increase the final hydrocarbon was studied. Due to the implementation of the cycling process, the formation pressure is maintained at the highest level compared to depletion development, increasing gas and condensate production. It should be noted that the industrial experience of introducing cycling process technologies at the Ukrainian gas condensate fields confirms its high efficiency. The practical implementation of reservoir pressure maintenance technologies according to different technological schemes will provide significantly higher technical and economic indicators for the development of gas condensate fields with significant reserves of retrograde condensate.
2. For the reservoir in the study, the optimal value of the dry gas injection period duration was established when developing a gas condensate reservoir with a high initial condensate yield. According to the evaluation of the simulated data, the optimal period for the implementation of the cycling process is 34.3 months. The final condensate recovery factor for the given optimal value of the duration of the dry gas injection period is 43.7%. When developing productive reservoirs for depletion, the predicted condensate recovery factor is 37.64%. Thus, due to the introduction of reservoir pressure maintenance technology, an increase in the ultimate condensate recovery factor by 6.06% is achieved. The results of the studies allowed us to assert the high technological efficiency of the introduction of secondary and tertiary methods for increasing the ultimate hydrocarbon recovery in the development of gas condensate fields with a high condensate yield.

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