

# Investigation of the influence of the carbon dioxide (CO<sub>2</sub>) injection rate on the activity of the water pressure system during gas condensate fields development

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**Abstract.** The development of gas condensate fields under the conditions of elastic water drive is characterized by uneven movement of the gas-water. Factors of hydrocarbon recovery from producing reservoirs which are characterized by the active water pressure drive on the average make up 50-60%. To increase the efficiency of fields development, which are characterized by an elastic water drive, a study of the effect of different volumes of carbon dioxide injection at the gas-water contact on the activity of the water pressure system and the process of flooding producing wells was carried out. Using a three-dimensional model, the injection of carbon dioxide into wells located at the boundary of gas-water contact with flow rates from 20 to 500 thousand m<sup>3</sup>/day was investigated. Analyzing the simulation data, it was found that increasing the volume of carbon dioxide injection provides an increase in accumulated gas production and a significant reduction in water production. The main effect of the introduction of this technology is achieved by increasing the rate of carbon dioxide injection to 300 thousand m<sup>3</sup>/day. The set injection rates allowed us to increase gas production by 67% and reduce water production by 83.9% compared to the corresponding indicators without injection of carbon dioxide. Taking into account above- mentioned, the final decision on the introduction of carbon dioxide injection technology and optimal technological parameters of producing and injection wells operation should be made on the basis of a comprehensive technical and economic analysis using modern methods of the hydrodynamic modeling of reservoir systems.

## 1 Introduction

The depletion mechanism of productive deposits plays an important role in designing the development of gas and gas condensate fields. Natural gas fields are characterized by gas and water pressure development drives. According to field data and research results, it has been established that under the conditions of the gas drive quite high coefficients of

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hydrocarbon recovery are achieved, which are within the range of 85-90% [1]. Factors of hydrocarbon recovery from productive deposits for which the active water drive is characteristic account for 50-60% [2-3]. The more active the water pressure system, the greater the saturation of the residual gas and the lower the gas recovery factor. Considering the value of the recovery factors at the water drive, we can conclude that as a result of the advancement of formation water in productive deposits, significant reserves of hydrocarbons are trapped [4].

Natural gas fields in most cases are multilayered and consist of heterogeneous permeability reservoirs. As field experience shows, production wells are usually placed unevenly over the area of the gas bearing area being consolidated in the central part. Under these conditions, in the process of field development there is an uneven flow of water into the gas-saturated zone with the advanced movement of the displacement front through the most permeable and most drained layers and zones. In the flooded area there are some zones left with initial gas saturation, which the water has bypassed.

The following methods of regulating the movement of water into the field are known [1, 4-10]:

1. Prevention of water inflow into the field by means of water intake (“unloading”) wells, which are drilled on the initial contour of gas bearing capacity. The method is technologically possible, but economically unprofitable due to the significant costs spent on drilling water intake wells, lifting water from wells, its collection, storage and disposal.

2. Prevention of water inflow into the field by creating an impermeable barrier (screen) on the initial gas-bearing circuit from insulating materials, which are pumped into the formation through specially drilled wells. The method is economically unprofitable and technologically unacceptable, as even in a homogeneous formation it is impossible to create a continuous impenetrable screen along the entire thickness of the formation and the perimeter of the gas field.

3. The choice at the design stage of the field development of a certain number of wells, the system of placing them on the area, the intervals of opening of productive layers, the sequence of commissioning and technological modes of operation, which would ensure uniform movement of water in the field over the area and through the section.

A combined system of selective drilling in and development of productive formation has been used in multilayer deposits of the Krasnodar Territory. In the central part of the field all the layers are drilled in the wells, and on the periphery separate well pattern is drilled on each layer. The number of peripheral wells on individual layers is chosen so as to ensure uniform advancement of the water front along the section of the productive stratum, or primary flooding of the lower layers.

At the stage of design of the field development, not all features of the structure of gas bearing deposits are fully known. Therefore, in the process of field development there is an uneven advance of the water front.

The operation of flooded wells has the following advantages:

1) provides full production of all gas-saturated layers in the productive section of the well, which are not killed by flooded formation water;

2) slows down in time or prevents flooding of the surrounding production wells;

3) the size of the flooded zone of the formation decreases;

4) part of the micro-trapped gas is taken from the flooded formations as a result of its expansion and further movement to the production wells;

5) macro-trapped gas from the sections of the formation with the initial gas saturation, bypassed by water, is involved into the development due to its movement through the flooded porous medium into the zone of reduced formation pressure with operating flooded wells.

Along side with the problem of regulating the inflow of water into the gas-saturated part of the formation, the actual direction is the extraction of trapped gas from flooded formations, in particular by displacing it by non-hydrocarbon gases or by blocking the water inflow. The

high technological efficiency of the trapped gas from displacement from the flooded model by nitrogen injection is evidenced by the results of laboratory studies performed at VNDIgaz [11-15]. Pumping nitrogen into the flooded layers allows us to increase the gas saturation of the porous medium, which creates conditions of trapped natural gas movement. It is expected that nitrogen will remain in the lower part of the formation and will only be partially extracted together with natural gas. According to the results of research on bulk models of the reservoir at a pressure of 3 MPa and a temperature of 200 °C, the displacement of natural gas by nitrogen at the Medvezhe gas field (Russian Federation) for 9 months allows to increase the gas recovery factor by 3.75% [15]. This is due to the involvement in the development of trapped gas from flooded formations and gas dissolved in formation water. According to the results of experiments, the highest coefficient of gas recovery (82%) is achieved by pumping nitrogen in the amount of 1.2 pores volume. The same studies were performed using another non-hydrocarbon gas, such as carbon dioxide [16].

The above studies on the extraction of trapped gas from flooded fields by reducing the pressure in them and displacing (replacing) the trapped gas with non-hydrocarbon gases are performed for homogeneous formations. This article considers the main features of carbon dioxide (CO<sub>2</sub>) injection into producing deposits at the boundary of gas-water contact in order to prevent intensive advancement of formation water into productive deposits and ensuring stable waterless operation of production wells.

## **2 Problem statement**

Rational system of field development of hydrocarbon deposits at the water drive should be based on systematic control over the inflow of formation water into productive deposits, as well as on control over flooding of production wells. Such control should be carried out on the basis of the analysis of dynamics of actual indicators of development. Based on the results of the conducted analysis, the peculiarities of the field development process and the factors that negatively affect the natural gas production process should be established. After identifying the factors and reasons that complicate the extraction of hydrocarbons provide recommendations for improving the system of field development.

Taking into consideration the significant residual reserves of natural gas trapped by formation water, there is a very urgent problem of developing ways to extract this gas and increase the hydrocarbon recovery factor. Given the fact that the complexity of the development of hydrocarbon deposits in the conditions of intensive advancement of reservoir water into productive deposits, it would be expedient to introduce technologies that would slow down the process of reservoir water advancement and ensure stable waterless operation of production wells for a longer period ensuring higher hydrocarbon recovery factors.

The problem of preventing the advance of formation waters and wells flooding in the fields of Ukraine is becoming increasingly important. Solving this problem is one of the areas of energy safety of the state.

## **3 Results and discussion**

Most natural gas fields are adapted to reservoir water systems and are developed under conditions of water pressure drive, which consists in entering the gas-saturated deposits of bottom or edge water, and are trapped by water in a porous medium in significant volumes of gas and watered wells [17].

The development of gas condensate fields at water drive is characterized by uneven movement of the gas-water contact (GWC) depending on the filtration-capacity characteristics of the reservoirs. In the flooded part of the deposit micro-trapped gas is

remained due to incomplete displacement of gas by water, as well as a significant volume of macro-trapped gas due to uneven advancement of the water front [18].

Determining the position of GWC is an important task of control, without which the rational development of deposits is impossible. The choice of the optimal complex of control over GWC should be based on modern scientific and technical achievements and field experience [17]. The rate of rise of the water-gas contact depends on many factors. The main factors that play a major role include changes in formation pressure, capillary forces and wettability of the rock.

Under conditions of water drive, which causes the appearance of water in the production of wells, wells are decommissioned after relatively small gas recovery. This is due to the peculiarities of the field arrangement of gas and gas condensate fields, which for technological and economic reasons usually do not count on gathering and processing gas with a high water content.

Known methods used to prevent the advance of formation waters and the production wells dewatering are aimed at minimizing the negative impact of the water drive on the development process and to increase the hydrocarbon recovery factor.

According to carried out numerous experimental studies, it was found that in most cases, in order to ensure more complete sweeping of the gas-saturated area of the deposit, it would be desirable to fully prevent the advance of formation water into productive deposits, but no practical solution to this problem was found [19]. Close contact of natural gas with formation water leads to the creation of favorable conditions for hydrate formation in flowlines and pipelines. Combating hydration requires additional financial costs, which from an economic point of view, sometimes taking certain measures to prevent the formation of hydrates in the flowlines and pipelines is not economically feasible considering the low natural gas production in compared to the water volume.

That is why the improvement of existing technologies and methods of field development should be aimed at reducing the negative impact of water on the development of hydrocarbon deposits.

The most common method of intercepting and slowing down the movement of formation waters is the injection of various hydrocarbon and non-hydrocarbon agents into special wells drilled on the initial gas-bearing contour. Carbon dioxide, nitrogen, a mixture of nitrogen and air are used as injection agents.

One of the successful methods in the field of increasing residual gas production for the depletion of hydrocarbon deposits is the method of injecting carbon dioxide (CO<sub>2</sub>) into the reservoir. Studies have shown that by injecting carbon dioxide (CO<sub>2</sub>) it is possible to additionally recover much more volume of gas compared to the options for developing the field on the depletion and to provide much higher gas recovery factors [20-23].

The technology of using carbon dioxide to displace residual gas trapped by water from gas and gas condensate deposits, which are developed in the conditions of water drive is the injection of CO<sub>2</sub> at the gas-water contact. Given the fact that the densities of carbon dioxide and water are significantly different, the injection of carbon dioxide can partially prevent the movement of water into productive deposits. CO<sub>2</sub> injection is carried out in order to create an artificial barrier between water and natural gas, which will block the selective advancement of formation water and thus ensure stable waterless operation of production wells.

Numerous studies have confirmed that CO<sub>2</sub> dissolves well in water with increasing pressure, but decreases sharply with increasing temperature and salinity. Taking into account the initial thermobaric conditions of productive deposits bedding and the presence of formation water, it can be stated that CO<sub>2</sub> will expand and partially dissolve in water, thus slowing down the movement and subsequent breakthrough of water into productive formations and flooding of production wells with the most permeable interlayers. Due to the difference in densities and mobility of carbon dioxide (CO<sub>2</sub>) comprising with methane,

it will be possible to create an artificial barrier between formation water and natural gas and provide much better displacement [24].

The aim of this work is to study the process of carbon dioxide injection at the boundary of gas-water contact, namely the influence of different injection rates on the activity of the water pressure system and the process of flooding production wells using numerical simulations.

A three-dimensional model of the gas deposit was created for conducting researches. The reservoir is vault, being developed by 10 wells "Production". Along the perimeter of the gas-bearing capacity, 12 injection wells "Injector gas" are placed on the border of the gas-water contact. To study the efficiency of the injection technology of carbon dioxide, which is injected at the boundary of the gas-water contact on the process of formation water advancement, several development options are considered, which differ in the volumes of carbon dioxide (CO<sub>2</sub>) injection.

To model the development of gas condensate deposits, it is assumed that production wells are operated with a flow rate of 80 thousand m<sup>3</sup>/day. Injection of carbon dioxide (CO<sub>2</sub>) into injection wells has been carried out for 5 years with the following flow rates: 20 thousand m<sup>3</sup>/day; 50 thousand m<sup>3</sup>/day; 100 thousand m<sup>3</sup>/day; 200 thousand m<sup>3</sup>/day; 300 thousand m<sup>3</sup>/day; 400 thousand m<sup>3</sup>/day; 500 thousand m<sup>3</sup>/day. The introduction of carbon dioxide injection technology is carried out simultaneously with the beginning of the gas condensate deposit development at an initial formation pressure of 42 MPa. Modeling of the field development process has been carried out for 30 years. When the content of carbon dioxide in the formation gas has reached 3%, the production of hydrocarbons from production wells is stopped.

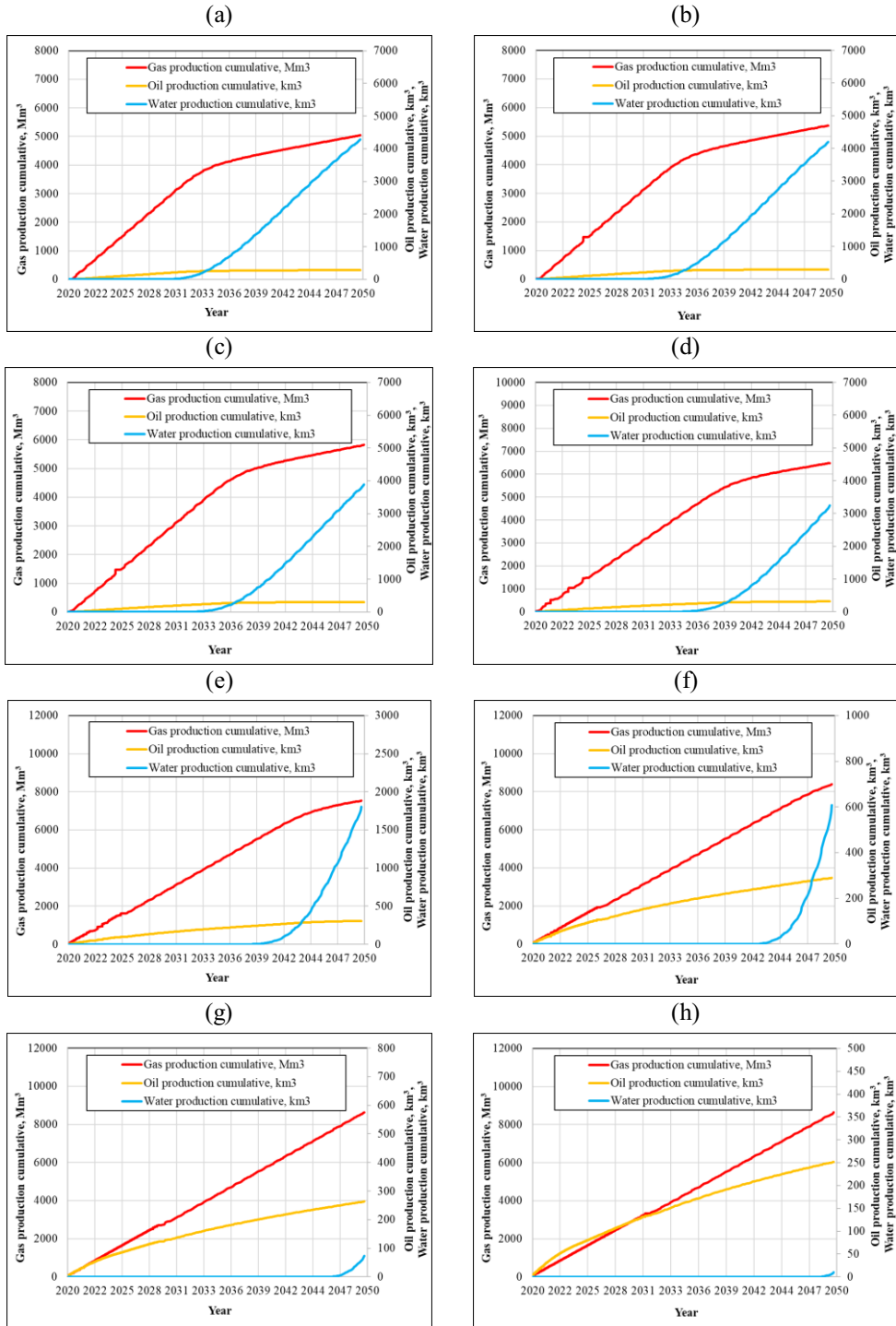
In order to take into account all the physical processes taking place in gas filtration in formation during the carbon dioxide injection at elastic-water drive, a composite model for gas condensate deposit was created and used [25-27].

Modeling of the water pressure system was performed using numerical simulation. The grid of the model is distributed outside the gas-bearing contour. Cells that are outside the gas-bearing contour are assigned the properties of an aquifer. As initial data for modeling of water pressure system such characteristics as volume of out contour water, pressure, the velocity of water inflow into the formation porosity and permeability of a layer are used. In addition to the available volume of water in the model below the gas-water contact, Fetkovich's aquifer was used.

Analyzing the simulation data, it was revealed that increasing the volume of carbon dioxide injection has a positive effect on the process of gas condensate formation development and slows down the movement of formation water into productive deposits. The injection of carbon dioxide will displace the water trapped in the water to the production wells and at the same time create an additional barrier between the water pressure system and the gas-saturated deposits.

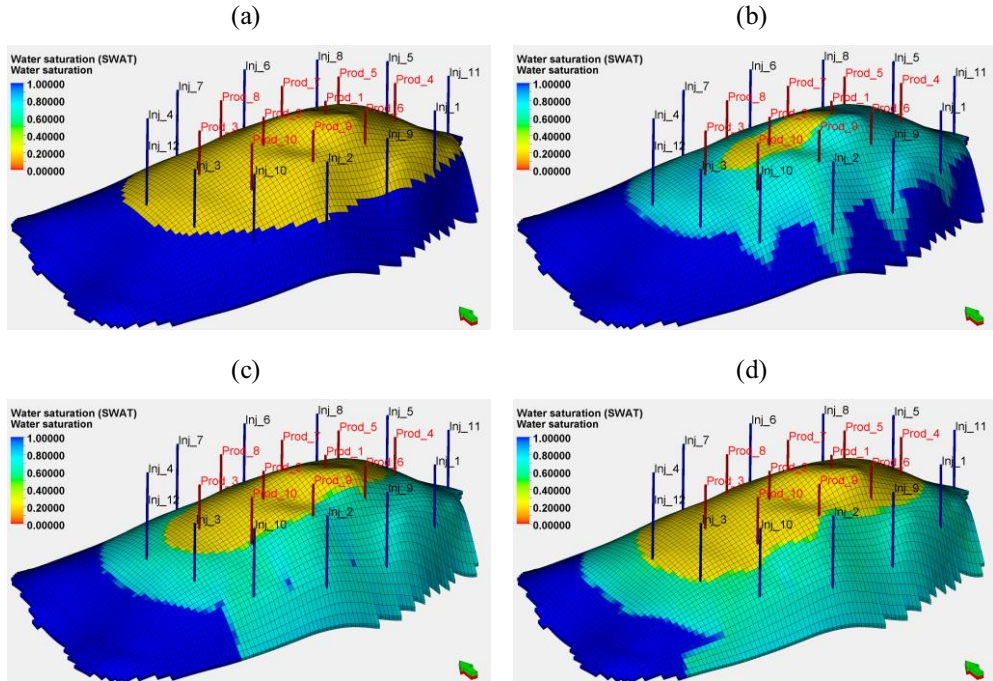
Modeling the process of carbon dioxide injection using a digital three-dimensional model allowed us to establish certain patterns and draw appropriate conclusions.

Increasing the rate of injection of carbon dioxide from 20 thousand m<sup>3</sup>/day to 500 thousand m<sup>3</sup>/day provides the largest accumulated gas production and the lowest water production. However, the obtained results, it is concluded that almost the main effect of the introduction of this technology is achieved by increasing the injection volume to 300 thousand m<sup>3</sup>/day. The injection of additional volumes of carbon dioxide (400-500 thousand m<sup>3</sup>/day) provides additional gas production, but the resulting additional gas production is not significant compared to the additional volumes of carbon dioxide that were pumped into the reservoir. The results of calculations of the expected accumulated production of hydrocarbons depending on the rate of injection of carbon dioxide into the injection wells are shown in Fig. 1.



**Fig. 1.** Dependence of the cumulative hydrocarbons production on the rate of carbon dioxide injection: depletion (a);  $Q_{injCO_2} = 20$  thousand  $m^3/day$  (b);  $Q_{injCO_2} = 50$  thousand  $m^3/day$  (c);  $Q_{injCO_2} = 100$  thousand  $m^3/day$  (d);  $Q_{injCO_2} = 200$  thousand  $m^3/day$  (e);  $Q_{injCO_2} = 300$  thousand  $m^3/day$  (f);  $Q_{injCO_2} = 400$  thousand  $m^3/day$  (g);  $Q_{injCO_2} = 500$  thousand  $m^3/day$  (h).

According to the results of the digital model initiation, it was found that CO<sub>2</sub> is well soluble in water and provides a slowdown in the selective flooding of the most permeable layers due to a fuller sweeping them by carbon dioxide displacement. The injection of carbon dioxide made it possible to partially maintain the reservoir pressure in the deposits and reduce the activity of the water pressure system, while delaying the flooding of production wells. The scheme of movement of the gas-water contact in the process of gas condensate reservoir development depending on the rate of carbon dioxide injection is shown in Fig. 2.



**Fig. 2.** Influence of carbon dioxide injection rate on the process of formation water movement in producing deposits and production wells: before the beginning of development (a);  $Q_{injCO_2} = 100$  thousand m<sup>3</sup>/day (b);  $Q_{injCO_2} = 300$  thousand m<sup>3</sup>/day (c);  $Q_{injCO_2} = 500$  thousand m<sup>3</sup>/day (d).

Analyzing the simulation data (Table 1), we can see that at an injection rate of 20 thousand m<sup>3</sup>/day, an increase in gas production by 0.07% and a decrease in water production by 1.62%. With increasing injection rate to 50 thousand m<sup>3</sup>/day, slightly better results were obtained, but these volumes of injection are not enough to control the process of formation water movement into producing deposits. The results of calculations of options for the development of gas condensate deposit with the rate of injection of carbon dioxide at the level of 100 thousand m<sup>3</sup>/day and 200 thousand m<sup>3</sup>/day allow us to reduce water production by 22.85% and 55.73% in comparison with the basic variant of development for depletion. The best result of residual gas displacement reserves is provided by the injection rate at the level 300–400 thousand m<sup>3</sup>/day. Cumulative gas production increased by 67–73%, while water production decreased by 83.92–97.76%, respectively, compared to the option of depletion. The injection rate at the level of 500 thousand m<sup>3</sup>/day provides approximately the same hydrocarbon recovery factors as the option with the injection rate at the level of 400 thousand m<sup>3</sup>/day. Taking into account above mentioned we can state that the option with the injection of 500 thousand m<sup>3</sup>/day is not feasible, but all of the above options for the development of gas condensate reservoir with the introduction of carbon dioxide injection technology should be evaluated from an economic point of view.

**Table 1.** Reduced data of modeling gas condensate field development.

Variant of development	Gas flow rate, thous. m <sup>3</sup> /day	Rate of injection, th.m <sup>3</sup> /day	Cumulative gas production, mln. m <sup>3</sup>	Gas production gain (from base variant), %	Cumulative water production, thous. t	Reduction of water production (from the basic variant), %
Base (on depletion)	80	–	5073.61	–	4395.09	–
Investing (CO <sub>2</sub> injection)	80	20	5404.35	0.07	4323.84	1.62
		50	5851.36	0.15	4021.46	8.50
		100	6519.92	0.29	3390.54	22.85
		200	7579.78	0.49	1945.48	55.73
		300	8471.49	0.67	706.74	83.92
		400	8761.50	0.73	98.64	97.76
		500	8771.67	0.73	18.61	99.58

Based on the results of the conducted technical and economic assessment, it is necessary to make decision concerning the optimal rates of carbon dioxide injection.

## 4 Conclusions

Modeling of field development allows us to establish what exactly needs to be done to stabilize hydrocarbon production, in particular under the conditions of elastic-water drive. The strategy for further work may include drilling new wells to involve into development micro- and macro-trapped gas, improvement of the mode of wells operation, and optimization of operation conditions.

The use of simulators makes it possible not only to refine the geological model, but also to work out ways to recover residual hydrocarbon reserves by calculating different options for field development in the future and choose the most optimal option for further development of the field.

The results of modeling the process of carbon dioxide injection allowed us to establish that increasing the injection rate to a certain value provides a high effect from the thanks to the introduction of the given technology. However, an additional increase in the rate of carbon dioxide injection does not lead to a significant increase of hydrocarbon recovery factors.

According to the results of modeling the development of the gas condensate reservoir on the basis of a digital three-dimensional model, it has been established that the optimal injection rate in this case should be in the range of 250-350 thousand m<sup>3</sup>/day. Cumulative gas production increases by 50-60% compared to the basic option of depletion drive. Water production is reduced by 60-80% according to the option of depletion drive.

Due to the injection of carbon dioxide, the inflow and advancement of water became controlled, which provided much higher factors of hydrocarbon recovery.

By calculating different options for field development, which included different rates of carbon dioxide injection based on a digital three-dimensional model, it was possible to compare the efficiency of each possible activity and assess the feasibility of conducting these works. The final decision on the introduction of carbon dioxide injection technology and optimal technological parameters of producing and injection wells operation should be made on the basis of a comprehensive technical and economic analysis by using modern methods of hydrodynamic modeling of reservoir systems.



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