Predicting the Impact of Carbon Dioxide Injection Processes into Formations Based on Hydrodynamic Modeling

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Abstract: A hydrodynamic model of the deposit was created in order to predict the impact of injection of CO2 into productive formations. According to the design solutions, one operational facility is being developed in the mode of artificial formation pressure maintenance. An areal five-point flooding system has been implemented. To calculate the indicators, a composite filtration model was used, in which three filtered fluids are considered: gas, water, oil – taking into account their real component composition. Based on the data obtained, the criteria for selecting candidate sites for carbon dioxide injection were identified. The model of a complex geological object made it possible to clarify the factors affecting the effectiveness of the method used. The choice of optimal sites for the injection of carbon dioxide should largely be based on ideas about the distribution of effective interlayers and their reservoir properties, as well as on the hydrodynamic relationship between wells. In addition, the parameters of the formation and fluid have a great influence on the filtration and solubility of the gas. Four variants of gas injection into the formation have been implemented. The results showed the dependence of the oil flow rate on the volume and duration of the CO2 injection cycle into the rim.

1 INTRODUCTION

The simulated object is classified as complex in terms of geological structure. The deposit has 6 layers (with an average effective thickness of about 4.5 m) separated by an extensive wedging zone. Disjunctive discontinuous disorders are distinguished. According to the development scheme, 1 operational facility is allocated, developed according to the areal nine-point system. The average depth of the object is 2150 m, the initial formation temperature is 40 °C. Due to the complex geological structure, the distribution of reservoir properties is uneven, the values of the porosity coefficient vary in the range from 0.1 to 0.25 u.f., with a median value of 0.159 u.f. The permeability coefficient is also unevenly distributed, ranging from 1.5 to 476 mD, with a median of 5.3 mD.

2 RESEARCH METHODOLOGY

The hydrodynamic model of the deposit was created in accordance with the requirements and recommendations of the regulations and methodological guidelines:

– Regulations on the creation of permanent geological and technological models of oil and gas and oil fields, RD 153-39.0-047-00.

– Methodological guidelines for the creation of permanent geological and technological models of oil and gas and oil fields.

According to the design solutions, one operational facility is being developed in the mode of artificial formation pressure maintenance. An areal five-point flooding system has been implemented.

To calculate the indicators, a composite filtration model was used, in which three filtered fluids are

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considered: gas, water, oil – taking into account their real component composition.

The properties of the fluids were taken from previously accepted values, which correspond to the results of experiments on deep samples of fluids taken from the layers of the deposit are shown in the table.

Table 1: Properties of fluids.

Components	Mol. % Concentration	Molecular weight, kg/kg-mol	Critical temperature, K	Critical pressure, abs bar.
CO_2	0.789	44.01	372.364	27.877
N_2	0.689	28.013	126.2	34.6
C_1	32.794	16.043	190.56	45.99
C_2	4.118	30.07	319.244	5.583
C_3	7.966	44.097	372.595	27.828
IC_4	1.699	58.123	427.545	34.445
NC_4	4.518	58.123	427.545	34.445
IC_5	1.539	72.15	474.831	34.312
NC_5	2.389	72.15	474.831	34.312
C_6	3.418	84	511.438	33.095
C_7	5.307	96	545.058	31.418
C_8	5.287	107	571.579	29.573
C_9	29.485	121	600.421	27.185

Components	Acentric factor	Critical volume, m3/kg-mol	Critical volume (for viscosity calculation), m3/kg-mol	Relative density
CO_2	0.224	0.118	0.094	0.486
N_2	0.038	0.089	0.089	-
C_1	0.012	0.097	0.099	-
C_2	0.627	0.008	0.146	0.292
C_3	0.225	0.118	0.2	0.489
IC_4	0.218	0.249	0.259	0.589
NC_4	0.218	0.249	0.255	0.589
IC_5	0.242	0.333	0.306	0.651
NC_5	0.242	0.333	0.313	0.651
C_6	0.266	0.385	0.335	0.693
C_7	0.292	0.427	0.377	0.727
C_8	0.316	0.462	0.418	0.749
C_9	0.348	0.505	0.473	0.768

Relative permeability is the ratio of the permeability of the rock for a given phase at a given saturation to the permeability of the rock at its full saturation with this phase. Relative phase permeabilities are a function of saturation, which depends on many factors. Relative phase permeabilities (RPP) according to the hydrodynamic model are shown in Figure 1.

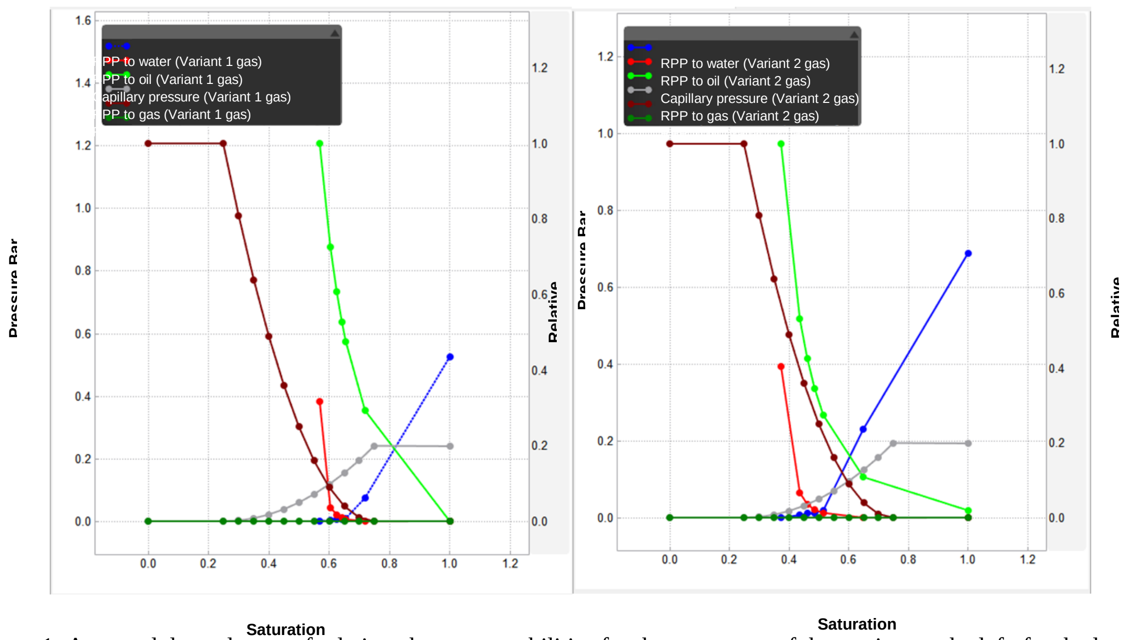


Figure 1: Accepted dependences of relative phase permeabilities for the upper part of the section on the left, for the lower – on the right.

The initial state of the development object was set using the equilibrium initialization option. At the same time, in order to preserve the oil saturation field obtained in the geological model, the initial water distribution was introduced and the capillary pressure curves in the oil-water system were scaled so that this water distribution in the initial solution turned out to be balanced.

The quality of the model is largely determined by the correctness of the assignment of information on wells, therefore, prior to the construction of the object model, the initial geological and field information was carefully prepared and verified:

– coordinates of wells;
– perforation intervals;
– results of hydrodynamic studies;
– results of field and geophysical research;
– well operation modes for specific dates (downhole and wellhead pressures, liquid rates, water cut, etc.).

Comparison of actual and calculated technological indicators for wells shows a satisfactory quality of adaptation of the filtration model to assess the production of reserves.

The assessment of the effect of carbon dioxide injection was carried out at two sites characterized by high values of the density of oil reserves. Two working injection wells 14 and 24, located in the center of the area of increased reserves values, were selected as objects for injection of CO_2 (Fig. 2).

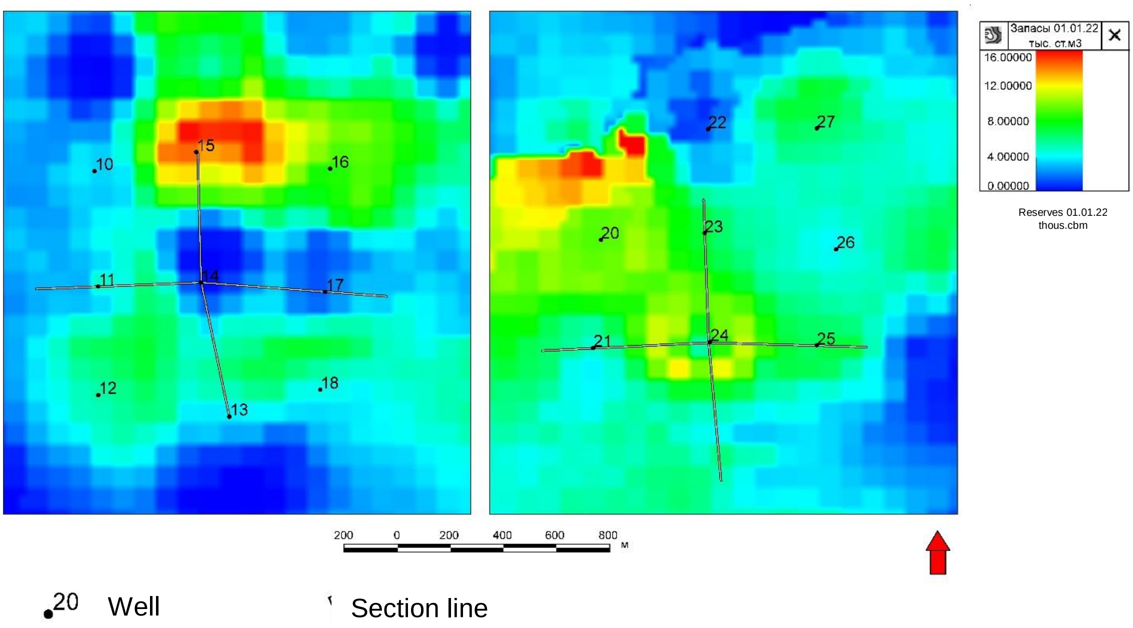


Figure 2: Maps of oil reserves in selected areas at the beginning of the calculation.

During the simulation, historical sampling and injection modes were established for injection and production wells. Restrictions on the operation of production wells were established by the historical flow rates of wells and the maximum water content of 98%. Water injection wells were limited by historical injectivity.

An interval of 5 years was chosen for the simulation period (from 01.01.2022 to 01.01.2028), while 4 different variants of carbon dioxide injection were implemented:

– The basic variant is that there is no gas injection;

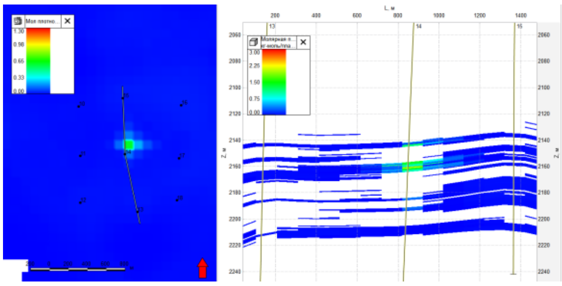
– Variant 1 – injection of CO_2 in twenty batches. The duration of one rim is 1 month, followed by a water injection cycle in the interval of 2 months. Limitation of gas injection by maximum pressure in the injection zone – 34 MPa;

– Variant 2 – provides for the same operating mode as in the above-described variant, with a gas injectivity limit of 10,000 m^3/day;

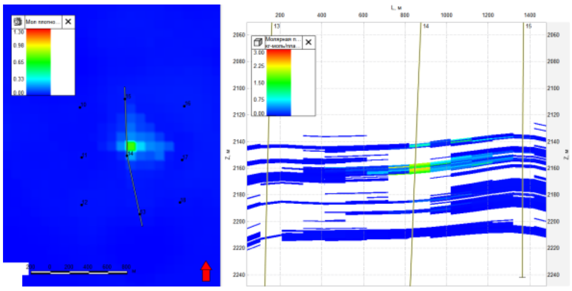
– Variant 3 – injection of 3 gas rims, duration 1 year. With a limited injectivity of 10000 m^3/day;

– Variant 4 – CO_2 injection into 12 rims. The duration of one injection cycle into the rim is 1 month, followed by a water injection cycle in the interval of 5 months. Limitation of gas injection by maximum pressure in the injection zone – 34 MPa.

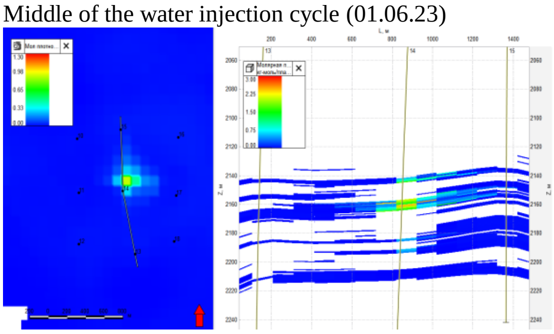
The control of the correctness of the injection simulation was carried out by viewing maps and sections. Figures 3, 4 show maps and sections with averaged data on the molar density of the injected gas for two control sections.



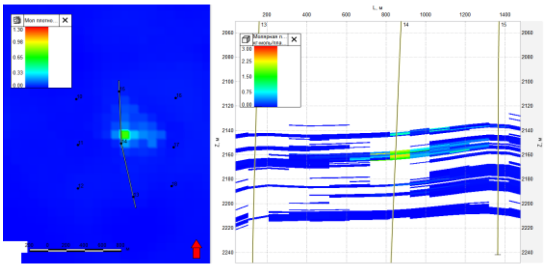
Middle of 1 CO2 injection cycle (01.06.22)



Middle of the water injection cycle (01.06.23)

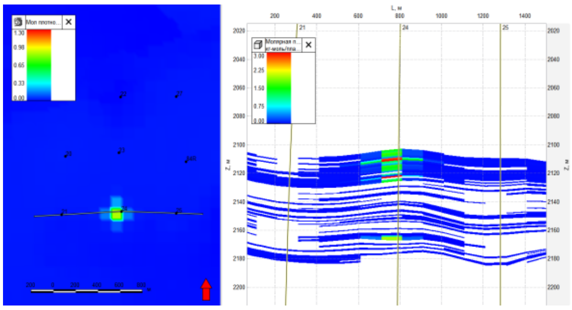


End of 1 CO_2 injection cycle, start of water injection (01.01.23)

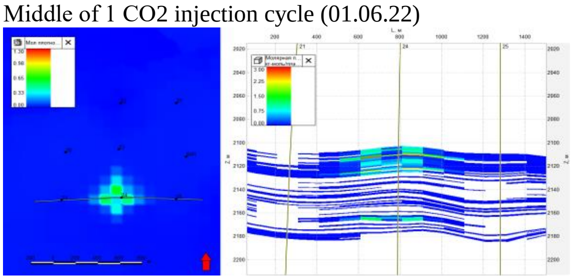


End of water injection, start of 2 CO2 injection cycle (01.01.24)

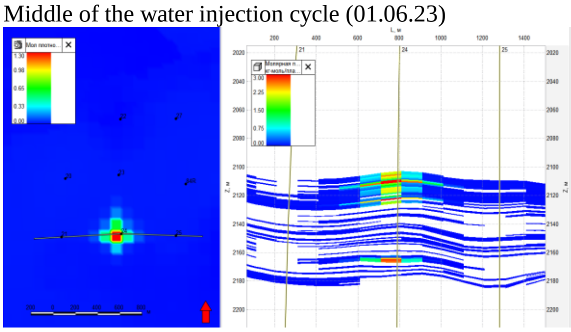
Figure 3: Map and section of molar density of CO_2 along the well section 14. Variant 3.



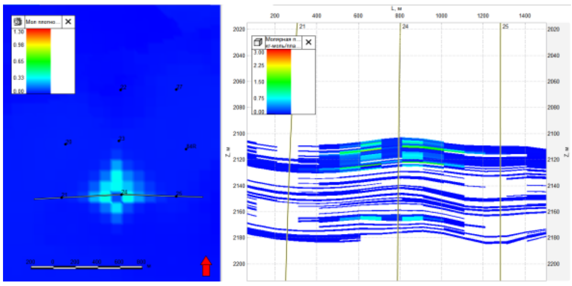
Middle of 1 CO2 injection cycle (01.06.22)



Middle of the water injection cycle (01.06.23)



End of 1 CO2 injection cycle, start of water injection (01.01.23)



End of water injection, start of 2 CO2 injection cycle (01.01.24)

Figure 4: Map and section of molar density of CO_2 along the well section 24. Variant 3.

3 STUDY RESULTS

Based on the results obtained, the uneven distribution of the injected gas over the area and over the section of productive formations is visible. As a consequence of the uneven distribution of reservoir properties, fluid filtration takes place in the most permeable areas and interlayers. This is most clearly manifested in the well site 14, where the main fluid flow is directed to the northeast.

To clarify the effect of the gas injection, cubes of the parameter inversely proportional to the viscosity (1/cP) were calculated. The average value for formations is 3.32 1/cP, when gas is injected in individual cells of the model, this indicator increases to values exceeding 100 1/cP (Fig. 5).

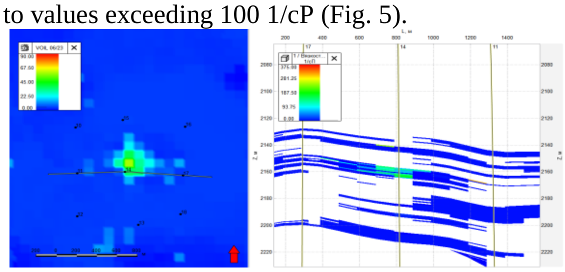


Figure 5: Map and section of the inverse viscosity parameter for the well section 14 as of 01.06.23.

The results of the increase in oil flow rate, the water content of products and the indicators of accumulated gas injection are shown in Figure 6-7.

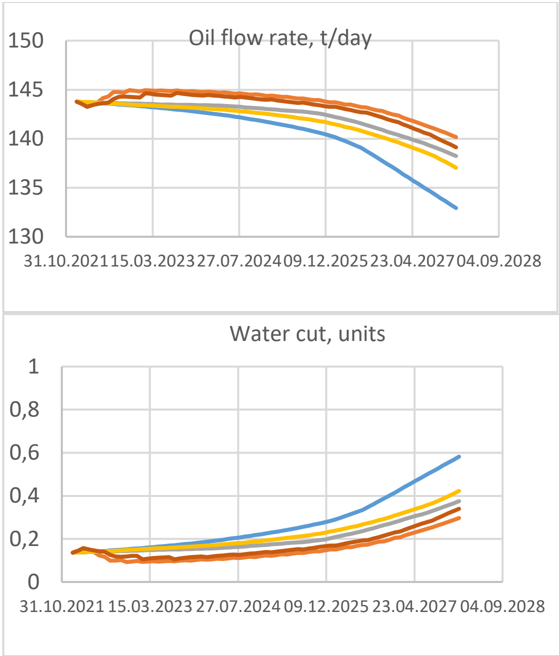


Figure 6: Dynamics of changes in oil flow rate and water content of products along the well section 24.

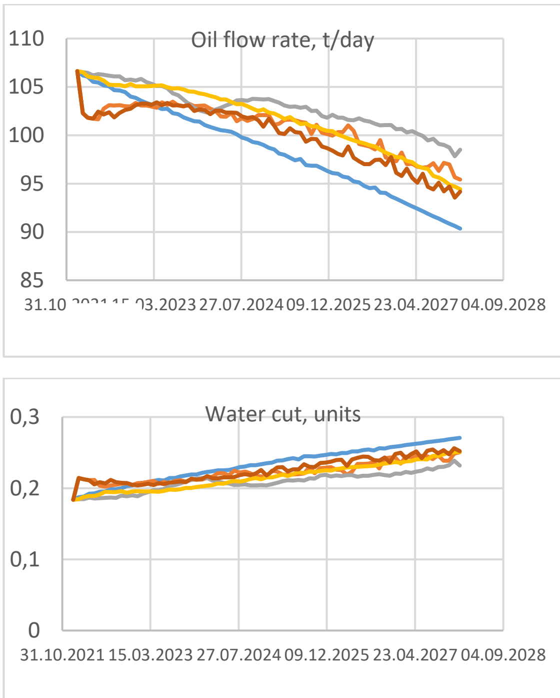


Figure 7: Dynamics of changes in oil flow rate and water content of products along the well section 14.

As can be seen from the graphs presented, the enhanced oil recovery technique used allowed to extend the period with fairly high oil debits and low water content of products. The greatest effect is observed in variants that are characterized by large volumes of gas injection (variants 1 and 4, in which the injection was controlled by a maximum allowable pressure of 34 MPa). However, the resulting effect is not much different from variants 2 and 3. Consequently, injection of large volumes of gas into the reservoir is not economically rational (Fig. 8).

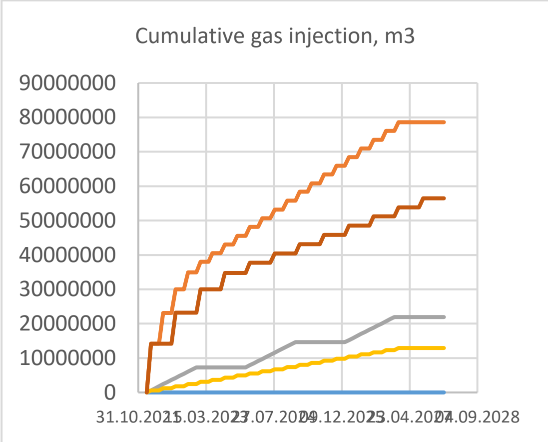


Figure 8: Accumulated gas injection by simulation variants.

4 RESULT DISCUSSION

Thus, the effectiveness of the method depends on the reservoir thermobaric conditions, the composition of the fluid, as well as on the distribution of the reservoir properties and the well system. The direction of the injected gas flow can greatly affect the result obtained. In the case of injection in the area of well 14, wells of the north-eastern direction received an additional increase in flow rate (well 15, Fig. 9). Whereas for wells in the southwestern part of the site, the increase in flow rate does not exceed 15% (well 18, Fig. 10).

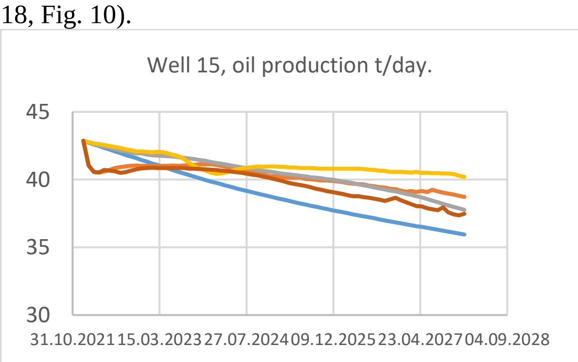


Figure 9: Flow rate of well 15 for the simulation period.

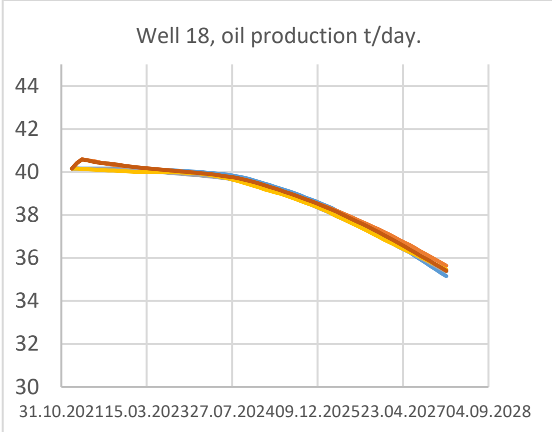


Figure 10: Flow rate of well 15 for the simulation period.

The same pattern can be traced for the site in the area of well 24. The effect of the injected gas is observed only in those producing wells that have a hydrodynamic relationship with the injection area of CO_2 (Figure 11). In the remaining wells, the effect is almost not observed (Figure 12).

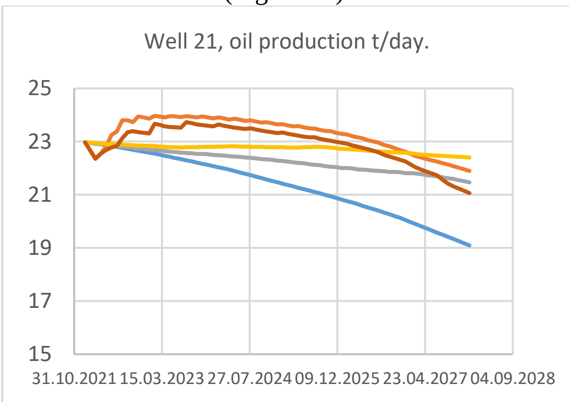


Figure 11: Flow rate of well 21 for the simulation period.

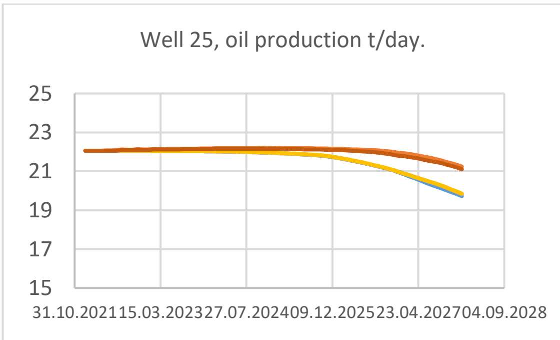


Figure 12: Flow rate of well 21 for the simulation period.

5 CONCLUSION

Based on the data obtained, the following conclusions can be formulated:

– the effectiveness of the method used depends on the conditions of the formation and the injected fluid;

– the effect of gas injection is greatly influenced by the hydrodynamic connection between wells, the heterogeneity of the formation and the reservoir properties;

– based on the data obtained during the simulation, the injection of large volumes of gas into the reservoir does not give a strong increase in oil production rates for producing wells.

The constructed geological and hydrodynamic model with a forecast for injection of CO_2 into the formation showed the effectiveness of the method. The applied measures will allow to increase the period with high oil debits in producing wells, as well as increase the production time of products with relatively low water content.

The choice of optimal sites for the injection of carbon dioxide should largely be based on ideas about the distribution of effective interlayers and their reservoir properties, as well as on the hydrodynamic relationship between wells.

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