DOI: 10.5604/01.3001.0015.7028

Volume 110 • Issue 1 • January 2022

Journal of Achievements in Materials and Manufacturing Engineering

International Scientific Journal published monthly by the World Academy of Materials and Manufacturing Engineering

Investigation of the efficiency of restrained oil displacement using of enhancing oil recovery methods

A.V. Uhrynovsky [a,*], L.B. Moroz [a], G.M. Kogut [b]

[a] Department of Oil and Gas Production, Institute of Petroleum Engineering, Ivano-Frankivsk National Technical University of Oil and Gas, 15 Karpatska str., Ivano-Frankivsk, Ukraine

[b] Leading Engineer at Laboratory of Intellectual Property Right Commercialization, Ivano-Frankivsk National Technical University of Oil and Gas, 15 Karpatska str., Ivano-Frankivsk, Ukraine

* Corresponding e-mail address: andrewu@i.ua

ORCID identifier: https://orcid.org/0000-0002-3886-9639 (A.V.U.)

ABSTRACT

Purpose: The purpose of this article is to highlight the main problems that arise during the final stage of oil field development. Based on the identified problems using the EORgui program, Petroleum Solutions Ltd it is necessary to select the most effective method to increase oil recovery and study the most optimal tertiary oil recovery method using a hypothetical field model as an example, which will ensure the maximum oil recovery factor.

Design/methodology/approach: Study of oil tertiary displacement efficiency by applying tertiary methods were performed using EORgui software from Petroleum Solutions Ltd and Petrel from Shlumberger.

Findings: The results of the research show that the most optimal method of oil recovery increasing for this hypothetical field is the injection of carbon dioxide. When using this method, the oil recovery rate reaches 23%.

Research limitations/implications: When using carbon dioxide, it is necessary to have sources of supply near the field, as well as increased corrosion of petroleum equipment is possible to occur.

Practical implications: The use of the proposed approach is an important condition for the effective extraction of residual oil reserves for most fields developed using the reservoir pressure maintenance system.

Originality/value: The article presents the characteristic features of residual oil location, reveals the conditions for effective usage of methods to increase oil recovery and their selection procedure.

Keywords: Oil, Field, Oil recovery coefficient, Tertiary method, Formation pressure maintenance

Reference to this paper should be given in the following way:

A.V. Uhrynovsky, L.B. Moroz, G.M. Kogut, Investigation of the efficiency of restrained oil displacement using of enhancing oil recovery methods, Journal of Achievements in Materials and Manufacturing Engineering 110/1 (2022) 27-34.

DOI: https://doi.org/10.5604/01.3001.0015.7028

ANALYSIS AND MODELLING

1. Introduction

The main reason for the decline in oil production in Ukraine and in the world is the natural transition of great number of major fields in terms of production and reserves to the late (final, completive) stage of development. This is primarily due to the depletion of active reserves, after the extraction of 80-85% of oil from the approved initial reserves. Regarding this, the share of hard-to-recover reserves in the structure of hydrocarbon reserves is constantly increasing, and their development is carried out at a slow pace. The average final oil recovery in various countries and regions of the world ranges from 25 to 40%.

Considering the practice in Ukraine the final oil recovery of productive formations at such fields does not exceed 30% of the initial balance reserves. The volumes of such reserves over the last 30-year period have almost tripled and exceeded 70% of the total reserves [1]. In Ukraine, the share of such reserves is, first of all, consists of residual hydrocarbon reserves, which are formed at a late stage of field development. These reserves include: oil reserves in low-permeability reservoirs, reserves of highly watered deposits, high-viscosity oil and bitumen. The structure of residual oil reserves is also aggravated by the fact that hydrocarbons are extracted mainly from the active part of the reserves [2].

The analysis of oil fields state development in the world shows that most of the fields are developed using a reservoir pressure maintenance system (RPM) by injecting various oil recovery agents (mainly water or gas) into the cavity [3,4]. However, despite the fact that RPM by waterflooding is a fairly simple and developed method, at the final stage of development such method of oil deposits developing becomes ineffective, due to the fact that it no longer provides the required final degree of oil displacement from deposits. This is mainly due to the immiscibility of oil and water, the instability of the displacement front, incomplete coverage of the reservoirs by the waterflooding process, both along the section of the productive formation and in area, etc., therefore, the selection of technologies at the final stage of development is an urgent problem of present time.

2. Literature review

The occurrence of residual oil is characterized by the uneven saturation of the reservoirs, which appear itself at different levels, starting from individual pores (restrained oil) and up to the individual sections of the reservoir. The second characteristic of residual oil is the difference in its physical properties from the properties of natural (primary) oil. During the development of a reservoir, as a result of the interaction of pumped and reservoir waters with natural oil and the reservoir layer, various changes in the natural properties of oil and reservoir occur. Considering the volumes of residual oil, scientists distinguish two main types:

1. Residual oil of the macro level (pillars, impermeable layers, stagnant zones, lenses). The residual oil contained in these reservoirs retains its original properties.
2. Residual oil of the micro-level (film, adsorbed on the surface of the porous medium, capillary-clamped (residual oil in the form of globule drops, which are separated from the skeleton of the porous medium by a film of water). They are formed only in the flooded parts of the formation and their composition differs from the composition of the initial oil.

The form and distribution of residual oil reserves also depend on a complex of natural and artificial factors that determine the final oil recovery factor, namely: oil viscosity, reservoir properties, initial state of oil and gas, reservoir development mode, well grid density, etc. [5]

It is characteristic that two-thirds of hard-to-recover reserves are located in deposits at depths of more than 2500 m and more than 57% are concentrated in the fields of the Carpathian region, where almost all oil reserves are classified as hard-to-recover [6,7]. The severity of the problem of oil recovery increasing from reservoirs is due to the fact that with a steady decline in oil production, depletion of easily accessible reserves and high-performance reservoirs located in favourable natural and geological conditions, there are practically no effective technologies for the development of hard-to-recover oil reserves in the country. According to experts' opinions, the share of hard-to-recover oil reserves in the world exceeds 1 trillion tons. The solution to the problem of increasing the efficiency of fields developing with hard-to-recover reserves is associated with the creation of new and improvement of existing physical and chemical methods that ensure a more complete oil recovery and a decrease in the production of associated formation water.

After applying conventional waterflooding, hydrodynamic methods and methods that improve waterflooding, a significant part (up to 70%) of the initial balance of oil reserves remains in the reservoirs. This residual oil can only be displaced by such working agents that mix with oil and water or have an ultra-low interfacial tension [8].

Analysis of the results obtained after the introduction of new methods for oil recovery increasing at watered formations shows that for deposits at a late stage of development, the most promising are physical and chemical and microbiological methods of stimulating the formation. The use of these methods for influencing watered reservoirs can lead to an increase in the displacement ratio of oil from a porous medium or to an increase in the sweep efficiency, or at the same time to an increase in both the displacement factor and sweep.

The gas stimulation method is one of the most effective and widespread methods in the world. These days, many effective field development technologies have been developed using gas methods to increase oil recovery, such as high-pressure gas action, water-gas action.

The most promising and highly potential methods at the final stage of development include: displacement of oil by carbon dioxide (CO_2), displacement by micellar solutions, ASP-flooding, flow and injection technologies and technologies for levelling the injectivity profile [9]. The physical significance of carbon dioxide application is based on the high degree of its dissolution in reservoir fluids (oil and water), as well as the dissolution of some oil components in it [10]. All this leads to an increase in the oil recovery factor. At pressures greater than a certain value, mutual mixing of phases (oil and carbon dioxide) occurs, at which very high values of the oil recovery factor (up to 0.95) are achieved [11].

An important feature for the effective application of oil recovery enhancement methods is their correct selection. Application criteria determine the range of favourable properties of fluids and formation, at which the most effective application of a particular method and obtaining the best technical and economic indicators of development is possible.

3. Methods and materials

The Petrel software (Schlumberger) was used to select an effective method for restrained oil displacement. To begin with, a static model of a hypothetical field was configured. To execute the geological model, data obtained as a result of geological, geophysical and seismic studies, as well as laboratory studies on cores, were operated. For the input parameters, the averaged values of the depth, porosity, and permeability were used, which were necessary to configure a reservoir model.

The first stage was the elaboration of the field geological model. Using the created structural map, maps of the surface of the horizons, namely the top and bottom, were designed, as well as the presence of faults was simulated. The generation of the horizon surface was carried out by transferring isolines with different depths and their limitations in the spatial environment, while it was necessary to observe the appropriate scaling rules (Fig. 1).

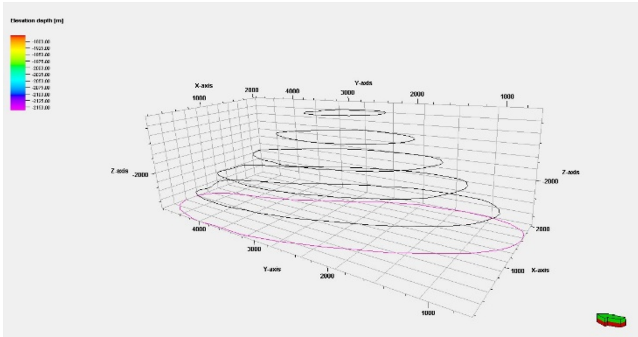

Fig. 1. Configuration of isolines and their limitations in space

Based on the designed isolines, a three-dimensional model of the reservoir surface was created (Fig. 2). Structural and stratigraphic framework of the model consists of horizons – stratigraphic boundaries of layers.

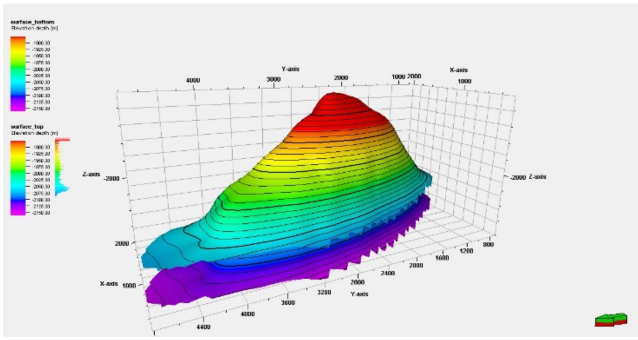

Fig. 2. The 3D surface of the top and bottom of the formation

Subsequently, the formation matrix was created, that is, a three-dimensional net consisting of vertical and horizontal lines (3D-grid). In this case, the built 3D grid has a net size of 50x50 meters. For a more accurate configuration of the model, the structural features of the reservoir were taken into account, that is, they reflected the presence of impermeable or low-permeable layers and interlayers. In this model, there are two low-permeability zones, composed of members of low-permeability clogged sandstones. To display them, additional zones were created, which during further modelling will be endowed with the corresponding reservoir properties. The final step in the structural frame configuration is to set the thickness and orientation of the layers between the horizons and the 3D GRID. The formations are mainly represented by the alternation of permeable and low-permeability interlayers. In order to reflect these low permeability layers, the NTG (Net to Gross) option was used, which is designed to limit porosity and permeability in the corresponding layers.

The obtained layers, in combination with the spatial web of the matrix, form the cells of the 3D structural net, to which the petrophysical properties will be assigned during the further modelling process. Based on the analysis of field development projects, it is known that the porosity of rocks varies significantly. For the deposits of the Carpathian region, the value of the porosity of the rocks is from 1 to 28% on average. For further modelling of the conditional field, the change in the porosity value was set in the range from 5 to 15% (Fig. 3).

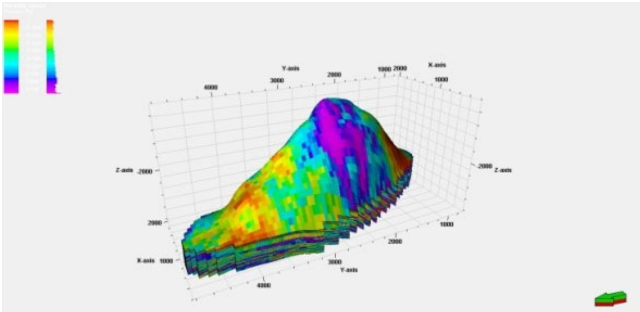

Fig. 3. General view of the model of porosity spatial distribution

The range of permeability values was set from 0.1 to 25 mD. In general, the permeability for low-permeability zones should not be equal to zero, because during hydrodynamic modeling, such zones participate also in the processes of fluid flow. Regarding this, for such zones, a minimum value is given within the limits inherent in non-collectors (0 <kp <0.1).

The spatial distribution of permeability was configured in two directions of the coordinate axes – IJ (horizontal) and K (vertical). Figure 4a shows the results of the spatial distribution of permeability in the direction of the IJ axis, and Figure 4b – in the direction of the K axis. In the direction of the K axis, the permeability value is 10 times less, taking into account the anisotropy of the formation and the force of gravity.

Additionally, the values of the initial oil and water saturation were set to configure a more complete flow model of the reservoir. In the model under study, the initial saturation values were 0.7-0.9 for oil and 0.1-0.3 for water. The initial saturation was an important parameter that was required for further hydrodynamic calculations.

The selected field contained four production oil wells and two injection wells. The design of these wells is shown in Figure 5. In order to design a well, the following elements are required: cemented casing, production casing, packer, bottomhole, cement bridge, appropriate perforation interval.

a)

b)

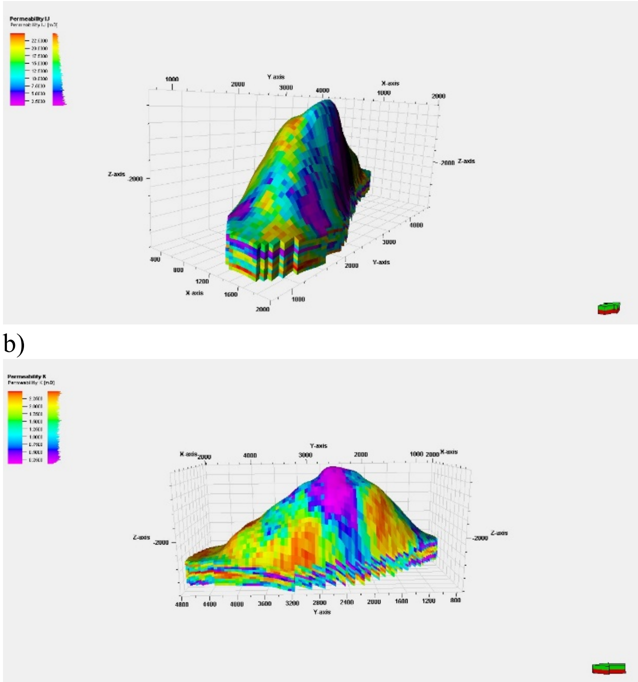

Fig. 4. Spatial distribution of permeability along the axes IJ (a), K (b)

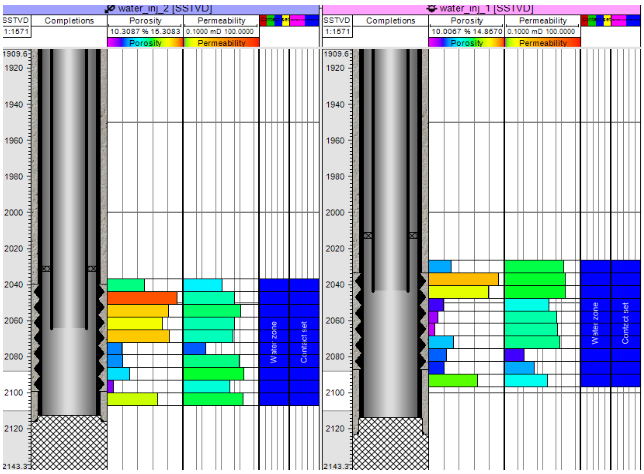

Fig. 5. Configuration of well with construction elements

The spatial location of the wells and their depth is shown in Figure 6. This stage is the final process of a static model configuration.

To configure a hydrodynamic model, the Black Oil model was used. This model assumes the presence of three phases, moreover, water and oil do not mix and do not exchange masses, and the gas is dissolved in water and oil.

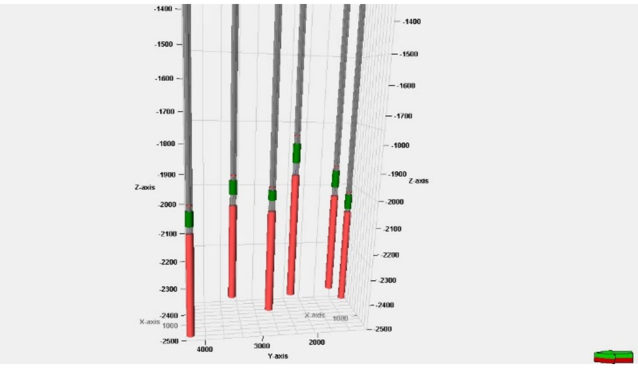

Fig. 6. Spatial location of the well

It is assumed that fluids in the formation are at constant temperature and in a state of thermodynamic equilibrium. Here PVT curves are presented as a function of the dependence of volumetric coefficients, gas content and viscosity on pressure.

At the first stage the Initial Conditions and reservoir fluid properties were set. The data required for this process were: minimum and maximum reservoir pressures, reservoir temperature, oil saturation pressure, oil density, gas and water density, oil viscosity.

For configuration of the modelled object hydrodynamic model the following input data were assigned: minimum formation pressure of 15 MPa, maximum formation pressure of 30 MPa, formation temperature 70°C, oil density 850 kg/m^3, other data was set automatically.

PVT properties of the configured Black Oil model are presented in Figure 7.

The phase permeabilities for the three-phase system were determined with the data of two-phase flow in the oil-water and oil-gas systems. For the case of three-phase flow, the relative phase permeabilities for water (Krw) and for gas (Krg) depend only on the respective saturations, and the relative phase permeability for oil (Kro) is a function of all saturations. The graphical dependence of the saturation parameters and the dependence of the elastic properties of the rock are shown in Figures 8, 9.

In general, three development methods were considered for a hypothetical oil field. The first method is for depletion development of the field, which is basic and reproduced the development history. With this development method, those conditions will be created that are characteristic of depleted fields at the final stage of development. According to the second development method, a reservoir pressure maintenance system will be introduced at the field by pumping water into the reservoir.

The second development method provides the field development by pumping water into the reservoir, with the development duration up to 30 years. To implement the waterflooding process, the water volume of 10-20 m^3/day is pumped into injection wells.

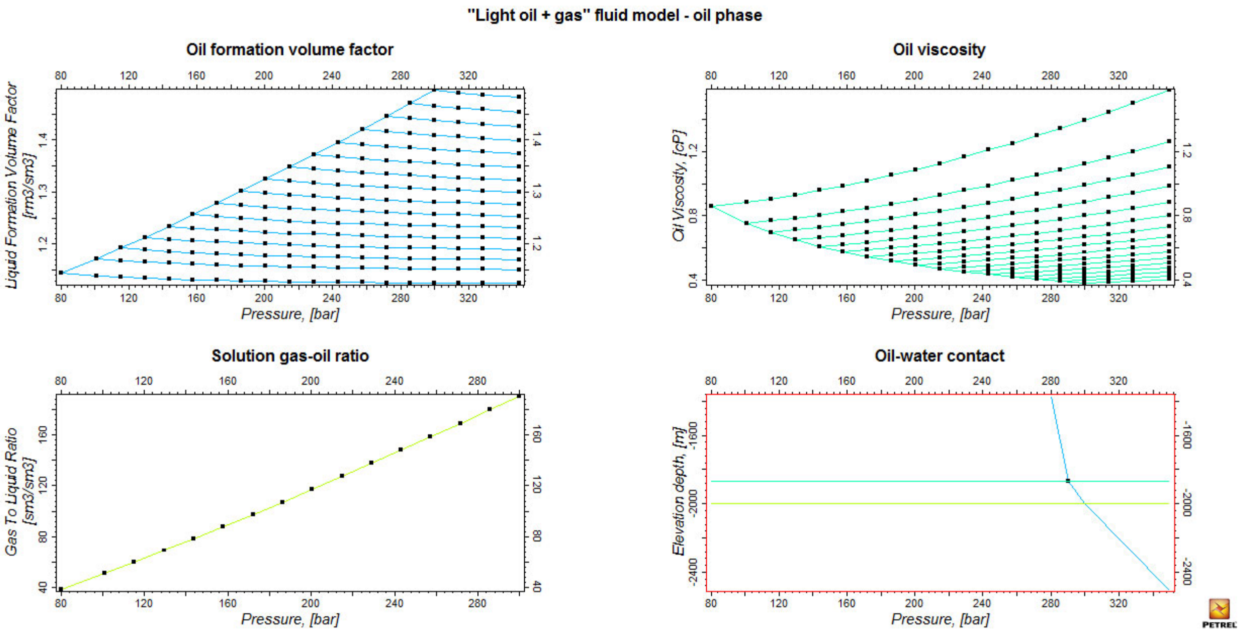

Fig. 7. PVT properties of the configured fluid model

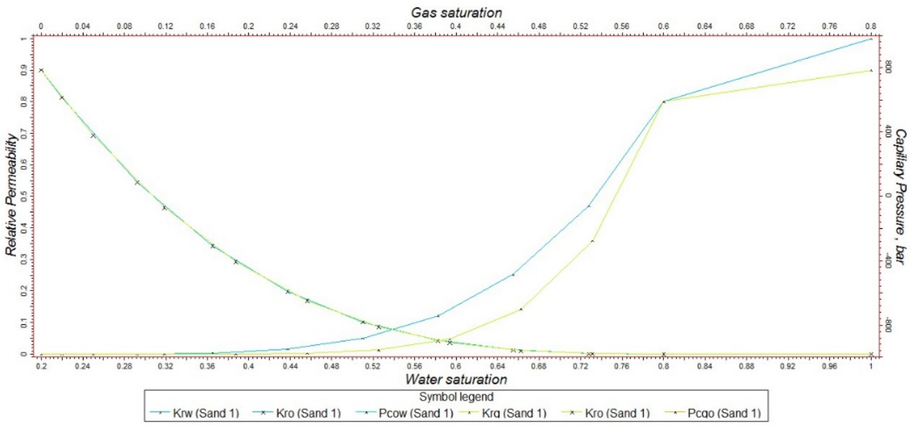

Fig. 8. Relative phase permeability curves

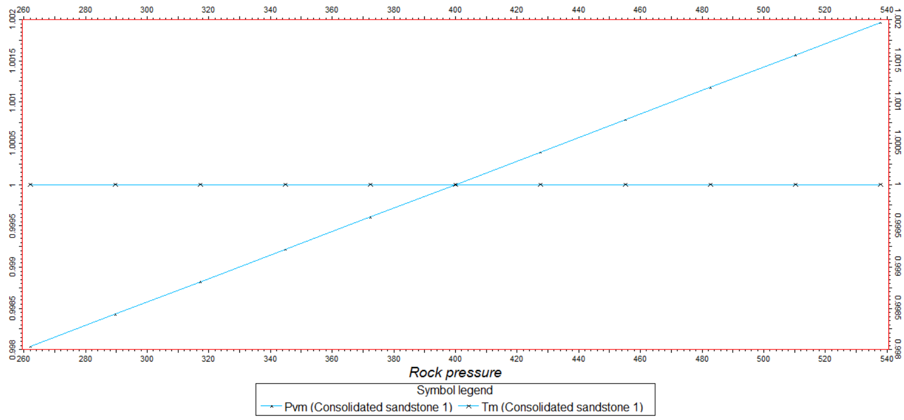

Fig. 9. Graphic dependence of rock elastic properties

The third development method concerns the implementation of the tertiary method [4]. The method considers the field development with a PPT system, and in the future, one of the tertiary methods of increasing oil recovery is being implemented. The choice of the most optimal tertiary oil recovery enhancement method for a field is one of the important stages, and depends on various factors and affects the effectiveness of the oil recovery enhancement method application. Such a process is unique for each field, because while the selection both the properties of fluids, the geological conditions of occurrence of a particular field, the parameters of the reservoir rocks, as well as the profitability of this process and other economic aspects are assessed [5,6].

To select the optimal method, one of the programs, namely EORgui, by Petroleum Solutions Ltd, was used, being developed on the basis of a publication in the Society of Petroleum Engineers in 1996. The main function of this program is the selection of an effective tertiary method of action. Such a selection is carried out on the basis of an analysis of an extensive database of field development both with methods implemented at these fields, and an analysis of the effectiveness of their application for given specific conditions.

In order to choose which of the methods of oil recovery increasing is best suited for a given field, data are needed on the properties of oil, rocks in which the deposit is located, as well as formation depth, permeability value and formation temperature.

4. Result and discussions

The simulated field has the following parameters: deposit depth is 2250 meters, reservoir is sandstone, oil saturation is 70%; API gravity of oil is 72.29 (850 kg/m^3), temperature is 158°F (70°C), average permeability is 10 mD.

For this field, the most optimal method for oil recovery increasing is the injection of Carbon Dioxide (Fig. 10). The following effective methods that can be implemented in the simulated field are: pumping of immiscible gases (83%), micellar-polymer and alkaline-micellar-polymer solutions (82%) into the reservoir.

Figure 11 shows the change in formation pressure over time according to the third method of deposit development. Thus, the reservoir pressure has been declining for nineteen years. Starting from 2000, where its value was 30 MPa and until 2019, when the value of reservoir pressure reached a minimum value of 16 MPa. In the future, for the period of ten years, the reservoir pressure is remained virtually constant (19-20 MPa), that is the result of the reservoir pressure maintenance system implementation.

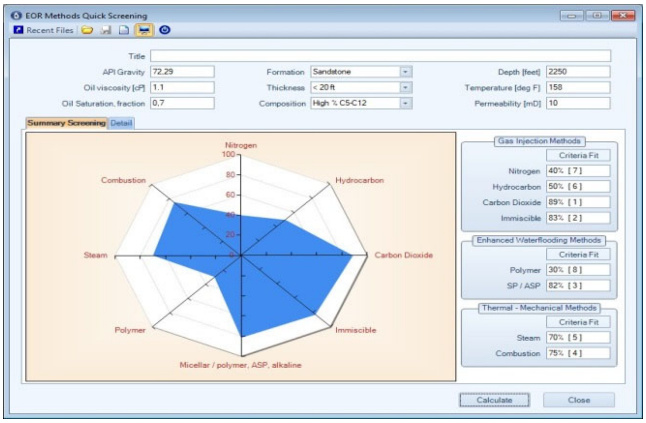

Fig. 10. Results of the EOR method selection for the simulated field in EORgui program

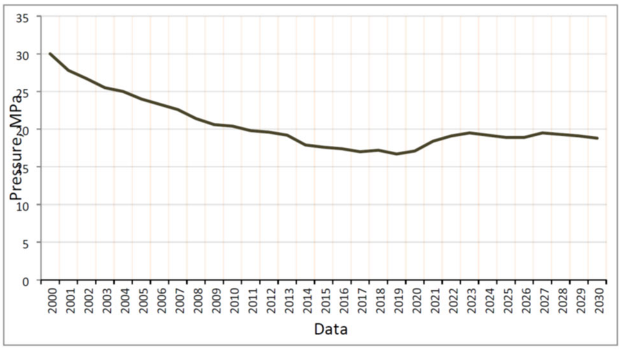

Fig. 11. Time change of reservoir pressure value according to the third development variant

Figure 12 presents a comparison of cumulative oil production for three development options. Curve 1 characterizes the development of an oil field in the depletion mode, according to which the cumulative oil extraction will amount up to 487.58 thousand tons. Since 2004, the accumulated oil production has been increasing (development method 2, curve 2) due to the implementation of a reservoir pressure maintenance system. According to this method, it is possible to ensure the accumulated oil extraction in the amount of 542.59 thousand tons. Due to the implementation of the second development method, the final oil recovery factor is 2% higher than the first.

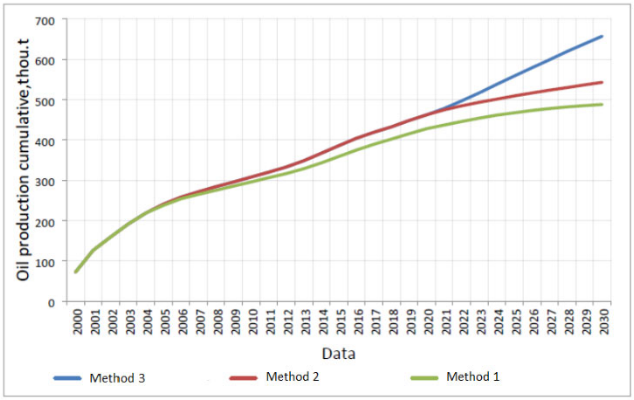

Fig. 12. Comparison of accumulated oil production according to three development method

Until a certain period of development, waterflooding as a secondary production method can provide the required volumes and rates. However, the effectiveness of this method sharply decreases over time, when the ratio of water volumes pumped into the reservoir with the volumes of oil produced becomes significant. As a result of this method of action on the formation, zones not washed with water are formed, containing a significant part of oil. In order to attract this non-watered oil, it is necessary to implement tertiary methods of oil recovery increasing.

Thus, Figure 12 (curve 3) justifies that the most effective development method is the third one, since when applied, the cumulative oil production is maximum and amounts up to 657.65 thousand tons. According to the studies carried out, the best method for oil recovery increasing is the injection of carbon dioxide, the introduction of which has been recommended since 2021. The final oil recovery factor for the third development method is the maximum and is equal to 0.23.

5. Conclusions

The article investigates the efficiency of trapped oil displacement after waterflooding using tertiary methods of oil recovery increasing. According to the results of hydrodynamic modelling, three development options are proposed. The first option is for development in depletion mode, the second options is for the maintenance of reservoir pressure by waterflooding, the third – the use of a tertiary method of oil recovery increasing (injection of carbon dioxide into the reservoir).

According to the third development method, it is possible to achieve higher value of the oil recovery factor (0.23) than with the other two development methods (0.17 and 0.19, respectively). However, the effectiveness of this method of stimulating the formation depends on many factors and options. The effect of using CO_2 to increase oil recovery of reservoirs is expressed in an increase in the displacement efficiency due to the volumetric expansion of oil, its solubility and its mixing with oil, as well as a decrease in oil viscosity. However, the sweep efficiency is reduced compared to ordinary waterflooding. Another important factor is that when applying CO_2 to increase oil recovery, corrosion of injection and production wells and oilfield equipment is possible. A limitation on the use of CO_2, in addition to geological and physical criteria, is also the availability of necessary resources in the area of oil fields.

References

[1] V.M. Doroshenko, Yu.O. Zarubin, The main directions of improvement of field development systems and the potential for increasing oil production in Ukraine, Oil and Gas Industry of Ukraine 2 (2013) 27-35 (in Ukrainian).

[2] L.B. Moroz, Review of the implementation of technologies to intensify oil production and increase oil production in the world's fields. Physical and technical problems of energy production, Oil and Gas Energy 1/21 (2014) 22-31 (in Ukrainian).

[3] Ya.S. Vytvytsky, I.M. Ivanchenko, Methods of intensification of production in oil fields of Ukraine, Proceedings of the 6th International Scientific Conference of Young Scientists and Students, Vol. 1, DonNTU, 2012, 224-227 (in Ukrainian).

[4] S. Kalra, X. Wu, CO_2 Injection for Enhanced Gas Recovery, Proceedings of the SPE Western North American and Rocky Mountain Joint Meeting, Denver, Colorado, 2014. DOI: https://doi.org/10.2118/169578-MS

[5] V.S. Boyko, I.M. Dragan, N.Y. Zalivakha, Factors of formation and preventive directions of reducing the volume of residual oil in the deposit, Exploration and Development of Oil and Gas Fields 3 (2016) 7-18 (in Ukrainian).

[6] A. Wolf, A. Artemov, I.Z. Zeynalov, K.I Zherzh, The matrix of applicability of methods for increasing oil recovery, Young Scientist 4 (2020) 223-225 (in Russian).

[7] V.B. Volovetskyi, A.V. Uhrynovskyi, Ya.V. Doroshenko, O.M. Shchyrba, Yu.S. Stakhmych, Developing a set of measures to provide maximum hydraulic efficiency of gas gathering pipelines, Journal of Achievements in Materials and Manufacturing Engineering 101/1 (2020) 27-41.
DOI: https://doi.org/10.5604/01.3001.0014.4088

[8] G.K. Gimazova, A.K. Vakhitova, A.A. Verkhovykh, Review of methods for increasing oil recovery by flow diversion and alignment of the intake profile, Bulletin of the Kazan Technological University 10 (2013) 257-262 (in Russian).

[9] L. Moroz, A. Uhrynovskyi, V. Popovych, B. Busko, G. Kogut, Effectiveness Research of Physical and Chemical Methods Application for Oil Recovery Enhancing Using the ASP for the Strutynsky Oil Field Conditions, Journal of Management Systems in Production Engineering 28/2 (2020) 104-111. DOI: https://doi.org/10.2478/mspe-2020-0016

[10] V.M. Doroshenko, V.Y. Prokopiv, M.I. Rudy, To the introduction of polymer flooding in oil fields of Ukraine, Oil and Gas Industry of Ukraine 3 (2013) 29-32 (in Ukrainian).

[11] S. Matkivskyi, O. Kondrat, O. Burachok, Investigation of the influence of carbon dioxide (CO_2) injection rate on the activity of the water pressure system during gas condensate fields development, E3S Web of Conferences 230 (2021) 01011.
DOI: https://doi.org/10.1051/e3sconf/202123001011