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Numerıcal Modellıng of Surfactant-Polymer Floodıng Combıned wıth Law Salınıty Water Floodıng ın Matlab: Case Study ın Neft Dashları

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Численное моделирование поверхностно-активных веществ полимерного заводнения совместно с заводнением слабосоленной водой в Matlab на примере месторождения «Нефть Дашлары»

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The increasing global population has led to a surge in energy demand historically met by hydrocarbons. Despite the substantial investments made in the renewable energy sector, the oil industry still overs a predominant role to play in the contemporary world, and this trend is predicted to persist during the next few decades. However, considering the depletion of oil resources over time, new methods and technologies are being invented and developed to increase the efficiency of oil recovery.
One of the methods applied to increase oil recovery is decreasing the salt fraction in the injection water used for the pressure maintenance in oil reservoir. Results of this research project indicate that at a mineralization level of 0.02 %, oil recovery reached 26.1 %, compared to 22.2 % in the base case. Moreover, the oil recovery during polymer and polymer-surfactant flooding comprised 28.1 and 31.2 % (the highest number), respectively.

Ключевые слова:
заводнение с использованием слабосоленой воды, повышение нефтеотдачи, численное моделирование, полимер, поверхностно-активные вещества.

По мере увеличения численности населения на планете растет также и потребность в энергии, которую исторически в основном получают от углеводородов. Невзирая на масштабные инвестиции в сферу возобновляемой энергии с целью снижения зависимости от исчерпаемых источников энергии, нефтяная отрасль до сих пор играет существенную роль в современном мире и, согласно предположениям специалистов, данный тренд будет оставаться неизменным на протяжении еще нескольких десятилетий. Однако, учитывая уменьшение запасов углеводородных месторождений, специалисты активно работают над разработкой новых способов и современных технологий, способных технологически и экономически увеличить эффективность добычи нефти.
Одним из таких методов, способствующих повышению нефтеотдачи, является снижение массовой доли минералов, в том числе соли, содержащейся в составе закачиваемой в пласты жидкости для поддержания пластового давления. Результаты данного исследовательского проекта показывают, что при уровне минерализации, равной 0,02 %, количество нефтеотдачи составило 26,1 %, при этом базовый вариант заводнения составляет 22,2 %. К тому же показатели при применении полимера и полимерных поверхностно-активных веществ оказались 28,1 и 31,2 % (самый высокий показатель).

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Introduction

Maintaining reservoir pressure by water injection is one of the frequently used methods in the oil industry [1, 2]. This method helps to displace oil and maintain reservoir pressure to ensure more complete recovery of reserves from the field [3]. Both produced water and seawater can be injected during this technique [4].

In the last century it was paid little attention to the effect of water composition and concentration on oil recovery. One of the main tasks in the design of the reservoir pressure maintenance system (RPM) was to minimize reservoir damage in the event of a possible interaction between the injected fluid and the reservoir fluid [5]. In recent years the injected water has been added by the components which promote the increase of the reservoir wettability, and this, in turn, leads to enhanced oil recovery [2]. This technique met extensive application, especially during periods of low oil prices, which made oil production in large volumes more important from an economic point of view [6–12]. It should be noted that enhanced oil recovery during water injection by reducing its salinity is a cheaper method in comparison with the other ones [13].

It is also important to note that direct injection of fresh water into the reservoir is generally not recommended because it can cause clay swelling, resulting in reservoir damage and a dramatic decrease in permeability [17-19]. This may be caused by the fact that salts are added to the injected water. Filtration of fine particles can also affect oil recovery due to capillary effect [1].

The influence of brine concentration on oil recovery was described by J. Martin who argued that the use of slightly saline water for injection is a more effective method of reducing residual oil saturation than brine [11, 13]. Over the years, a number of experiments and studies have been conducted to test the effectiveness of injecting slightly saline water (LS) compared to injecting plain water. As a result, a number of researchers have found that the injection of slightly saline water into sandstone and carbonate reservoirs increased the oil recovery factor by reducing residual oil saturation in undeveloped zones [2, 6–10]. Another advantage of low-salinity water flooding for enhanced oil recovery is that such technique can be easily applied in combination with other methods, including injection of polymers, surfactants, foam, etc. [12–16].

Water flooding mechanisms with the use of low-salinity water

Filtration of fine particles [7–38]. Although the core with mobilized particles is generally affected by the salinity level, oil recovery is no longer dependent on salinity when the sandstone called Berea is fired at 800°C and metal oxides are removed by acid treatment [22]. All these factors – mobilized particles, oil and pre-saturation – are necessary for the effective influence of salinity on oil recovery [23].

Ca^{2+} and Mg^{2+}, having the ability to reduce the repulsive forces between rock and clay particles, stabilize the clay [24]. However, low-salinity water, which has a destabilizing effect, causes the movement of silt and clay particles that are carried by the water flow and block the pores. Due to this the trajectory of water flows changes. Such process leads to the displacement of residual oil from the corresponding zones [1, 22].

The experiments of Laguerre, Zhang and Morrow showed that the destabilization of fine particles did not significantly affect the percentage of oil recovery since the migration of fine particles alone is not enough. The osmotic effect, reduced ion binding, interfacial viscosity, oil viscosity and interfacial tension gradient arising in dependence to the brine composition also play an important role [5, 25, 38].

Reduction of interfacial tension [27, 37–39]. According to McGuire, low salinity mechanisms can be realized by increasing pH and decreasing interfacial tension [26, 39]. The increase in pH value can be caused by the exchange between hydrogen ions in water and adsorbed sodium ions. Increasing the pH value also makes it easier to extract organic matter from the clay [24].

The exchange between the adhering sodium and hydrogen ions presenting inside the injected water leads to the formation of –OH in solution, accompanying an increase in the pH value [8]. Fine particles are mobilized, causing a decrease in permeability, which increases the efficiency of displacement [25]. An experiment by Wald and Vogler (1992) showed that although there was a gradual decrease in permeability at pH < 9, this trend became more dramatic at pH > 11 [27].

When the pH reaches a high enough level the organic acids in the crude oil form surfactants that reduce interfacial tension. These surfactants can form oil-water or water-oil emulsions, thereby increasing the efficiency of injected water displacement. This effect can be observed only in the case when the pH value exceeds 9 [27].

Multicomponent ion exchange (MIE) [38]. Before low-salinity water is injected polar organic compounds in the crude oil are combined with polyvalent or divalent cations attached to the rock surface to form organometallic complexes. After MIE the brine washes out all organometallic complexes replacing them with uncomplexed cations [28].

Lager et al. (2006) found that even without any change in the salinity fraction of the water oil recovery can be enhanced by the removal of divalent cations from the core surface [20]. With roasting and acid core treatment the dependence on salinity disappears, and clay minerals lose their ability to exchange ions. This discovery also explains why low-saline water does not work in the extraction of mineral-rich oils. This is because it does not have polar compounds that can interact with clay minerals [28].

The proportion of salinity in the water should be reduced to a certain value to achieve the effect.

In their experiment, McGuire et al. (2005) did not achieve the expected result even when salinity was reduced from 23,000 ppm to 7000 ppm [39]. However, when this number was reduced to 1,700 ppm oil recovery increased significantly, indicating that this value should be kept below 5,000 ppm to be effective. This specific limit value varies depending on the properties of the reservoir. Therefore, before pumping brine of a certain mineralization it is necessary to carefully study the properties of the reservoir [18].

Variation of wettability as a function of pH [38, 39]. The use of seawater is considered to be an effective way to change wettability due to the ions it contains, such as SO42–, Ca2+ and Mg2+, which are able to change the charges of the rock, facilitating the process of separating the carboniferous components of oil from the surface, while increasing oil recovery [31–33].

In the course of his experiment Webb discovered the dependence of capillary pressure on the sulfate ion [21]. Moreover, the following relationship was established: the higher the temperature, the higher the oil recovery [34, 35].

Various mechanisms have been proposed for changes in wettability. They represent a change in the surface charge of the rock due to the adsorption of SO42– ions and the co-adsorption of Ca2+ ions, as well as the replacement of Ca2+ with Mg2+, which is more effective at high temperatures [33]. Negative SO42– ions attract positively charged ions. As the amount of Ca2+ on the positively charged surface decreases, they are attracted to the negative surface, allowing more negatively charged oil to be separated and increasing oil recovery. This effect intensifies with rising temperature [34].

Historically, the change in wettability has been one of the most optimal methods of enhanced oil recovery. Such changes have been achieved by injecting diluted seawater [10]. However, since this method does not have a significant effect on interfacial tension, it is now used to induce changes in fluid rock systems [34].

Double-Layer Expansion [20]. Double layer theory is based on the interaction between charged surfaces through a liquid. Repulsive forces between surfaces exist due to the expansion of the electrical double layer. Injecting low-salinity water into oil reservoirs stabilizes the aqueous medium, changing the surface from oil-wet to water-wet, which promotes efficient oil separation, making it easier to recover [29].

In the presence of divalent cations at the interface between water and oil or water and rock, there is a change from a water-wetted surface to an oil-wetted one. Scientists Liu and Kia claim that in the presence of Na+, the surface of kaolinite is negatively charged and the pH value is high, which is accompanied by the presence of a repulsive force between them [24, 40, 41]. Thus, the injection of low-salinity water increases the repulsion forces at the “oil-water” and “water-particle” interfaces, changing them from oil-wetted to water-wetted, which stabilizes the water [24, 26, 28, 30].

The presence of an aqueous medium between the oil and the mineral is necessary for their charge. Polar functional groups found in oil and minerals can behave in different ways: acidic (losing protons, becoming negatively charged) and basic (gaining protons, becoming positively charged). The effect of the forces of the double layer on the stabilization of the aqueous medium is felt more strongly when the brine salinity is low and there are monovalent ions in it, as this contributes to the increase in the pH value. pH plays an essential role in regulating the interactions between acids and bases, as well as in the formation of surface charge [8, 29, 30].

Dissolution of minerals [6, 21, 27]. Water with a high salt composition is able to dissolve a smaller amount of organic compounds; this process is called salting out. However, the reduction in salinity contributes to a more intensive dissolution of organic compounds, thereby increasing oil recovery.

Polymer Flooding

Chemical flooding has become widespread in reservoirs with permeability from medium to high. This method was first used in the early 1960s. in the USA, and then spread to the UK, France, Norway and Indonesia. Due to the fact that traditional injection of ordinary water without the addition of special chemicals to perform a specific function

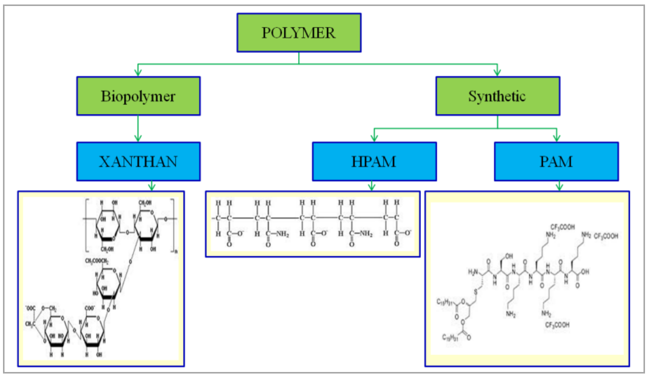

Fig. 1. Types of polymers for enhanced oil recovery (EOR) [50]

does not always give the desired results, therefore, today in a number of developed countries, including China, chemical flooding methods including polymer one are being developed [42, 43].

Displacement ratio and coverage ratio are the most important parameters. Flooding with polymers of high concentration is particularly suitable for reservoirs with high permeability and significant heterogeneity [44–46].

Polymers are extended organic structures formed by combining smaller units known as monomers. These molecules are flexible and have significant molecular weights ranging from $2{\cdot}10^6$ to $21{\cdot}10^6$ g/mol. To enhance oil recovery, the following types of polymers are most often used: polyacrylamide (PAM), especially in its partially hydrolyzed version (polyacrylamide polyelectrolyte) and xanthan gum (Fig. 1) [47–49].

Flooding, in which water is pumped into an injection well to displace oil to the producer well is one of the variants for enhanced oil recovery [54, 57]. Water injection can lead to an early water breakthrough, leaving residual oil in the reservoir due to the low viscosity of water and high heterogeneity of the reservoir. Water-soluble polymers increase the viscosity of water, which improves mobility control and also reduces the relative permeability of water compared to oil [55]. The main purpose of polymer flooding is to increase the efficiency of reservoir coverage, displace oil by increasing the viscosity of injected water and reduce the formation of lateral conings [49, 56].

Oil Displacement Mechanisms in Polymer Flooding

The chemical injection process is performed by increasing the difference in absorption pressures in small to medium sized pores of medium to low permeability, which is known as changing the injection profile. The polymer remains in low and medium permeability layers after pumping through them, increasing their resistance to seepage [50, 56].

Table 1

Elements Presenting in Polymer Structures and Their Characteristics [62]

Structure	Characteristics	Polymers
-O- in the link	Low thermal stability, thermal degradation at high T, only suitable at <80 C	Polyoxyethylene, sodium alginate, sodium carboxymethylcellulose, HEC, **xanthan gum**
Carbon chain in the link	High thermal stability, low degradation at <110 C	Polyvinyl, sodium polyacrylate, **polyacrylamide, polyacrylamide polyelectrolyte**
-COO in the hydrophilic group	Low level of adsorption on sandstones due to repulsive forces between the chains	Sodium alginate, sodium carboxymethylcellulose, **polyacrylamide polyelectrolyte, xanthan gum**
-OH or –CONH2 in the hydrophilic group	High chemical stability, but without repulsive forces between chains, high level of adsorption due to hydrogen bonding on sand rocks	Polyvinyl, polyacrylamide, **polyacrylamide polyelectrolyte**

The main direction in polymer flooding is to increase the volume of displaced oil [51, 52]. According to the modern theory of polymer flooding polymers increase oil recovery by reducing the mobility coefficient between the displacing and displaced phases by increasing the viscosity and reducing the relative permeability of the displacing agent (Table 1) [53, 57].

Methodology

The focus of this study was flooding with low-salinity water, followed by polymer and surfactants. In the course of this work, it was assumed that the oil lies in a reservoir with high clay content. In addition, one production well and one injection well were simulated.

Water was injected into the reservoir; it had a lower salinity than reservoir water. The outer boundary of the formation was supposed to be impermeable. The results of the experiment with injection water with 0.02% and 0.04 % salinity showed that oil recovery was higher when using water with 0.02 % salinity.

The technological parameters of the filtration process of the water-oil system were determined by the continuity equation for each component, the law of percolation, the equation of state of phases, saturation between phases, the concentration of salts in the aqueous phase and the action of capillary forces between phases,

The clay swelling factor was also considered. All these equations/factors were taken into account by combining the following equations:

$$div\left\{kh\left(\frac{f_n\rho_n}{\mu_n M_n}x_{ni}+\frac{f_w\rho_w}{\mu_w M_w}x_{wi}\right)gradp_o\right\}+ +\sum_{j=1}^{o_1}Q_{ij}^p(t)\delta\left(x-x_j^p,y-y_j^p\right)= =\frac{\partial}{\partial t}\left[mh\left(\frac{\rho_o S_o}{M_o}+\frac{S_w\rho_w}{M_w}\right)z_i\right], \quad z_i=x_{wi}V_w+x_{oi}(1-V_w), i=\overline{1,N}\ldots \tag{1}$$

$$div\left\{kh\left(\frac{f_o\rho_o}{\mu_o M_o}x_{oN+1}+\frac{f_w\rho_w}{\mu_w M_w}x_{wN+1}\right)gradp_w\right\}+ +\sum_{j=1}^{o_2}Q_{(N+1)i}^I(t)\delta\left(x-x_j^I,y-y_j^I\right)= =\frac{\partial}{\partial t}\left[mh\left(\frac{\rho_o S_o}{M_o}+\frac{S_w\rho_w}{M_w}\right)z_{N+1}+h\omega\frac{\rho_{w0}}{M_w}\right], \tag{2}$$

$$\sum_{i=1}^{N}x_{oi}=\sum_{i=1}^{N}x_{wi}=1,$$

$$\sum_{i=1}^{N+1}z_i=1,\ x_{oN+1}+x_{wN+1}=1,$$

$$div\left(khc\frac{f_w\rho_w}{\mu_w M_w}gradp_w\right)+\frac{\partial}{\partial t}\left[h\left(mcs_w+a\right)\frac{\rho_w}{M_w}\right]= =div\left(h\frac{\rho_w}{M_w}Dgradc\right)+\sum_{i=1}^{o_2}cQ_{(N+1)I}^I(t)\delta\left(x-x_I^I,y-y_I^I\right), \tag{3}$$

$$p_o-p_w=p_c(s,c)=\sigma\sqrt{\frac{m}{k}}\ldots \tag{4}$$

$$p_o(x,y,t)|_{t=0}=p_{o0}(x,y),c(x,y,t)|_{t=0}= =c_0(x,y),z_i(x,y,t)|_{t=0}=z_{i0}(x,y), \quad i=\overline{1,N},\left(0\le x\le l_x;0\le y\le l_y\right)\ldots \tag{5}$$

$$\frac{\partial p_w}{\partial x}|_{x=0,l_x}=0,\ \frac{\partial c}{\partial x}|_{x=0,j_x}=0,\left(0\le y\le l_y\right), \quad \frac{\partial p_w}{\partial y}|_{y=0,l_y}=0,\frac{\partial c}{\partial y}|_{y=0,j_y}=0,\left(0\le x\le l_x\right)\ldots \tag{6}$$

In this case, i are the hydrocarbon and non-hydrocarbon components, $(N+1)$ – water, $Q_{ij}^p(t)$ – production well flow rate, $Q_{(N+1)}^I$ – injectivity p_o and p_w of pressure, p_c – capillary pressure, $k=k(c,s_w), m=m(c,s_w)$ – absolute permeability and formation porosity coefficient depending on water salinity and water absorption, x_{oi}, x_{wi}, z_i – mole fraction of component i in oil, aqueous phases $f_o=f_o(s_w,c)$ and $f_w=f_w(s_w,c)$ – relative permeability to oil and water, $\rho_w=\rho_w(c,\Omega_w)$ – water density depending on salinity and gas solubility, ρ_{w0} – density of pure water, $\mu_w=\mu_w(c)$ – water viscosity, $M_n=\sum_{i=1}^{N+1}M_i x_{ni}$, $M_w=\sum_{i=1}^{N+1}M_i x_{wi}$ – molecular weight of oil and water, M_i – molecular weight of the component i, $\rho_o=\rho_o(p,T,x_{o1},x_{o2},\ldots,x_O)$ – oil density, $\mu_o=\mu_o(p,T,x_{o1},x_{o2},\ldots,x_O)\ldots$ – oil viscosity, $s_o=\dfrac{(1-V_w)\dfrac{M_o}{\rho_o}}{(1-V_w)\dfrac{M_n}{\rho_n}+V_w\dfrac{M_w}{\rho_w}}$ – oil saturation, V_w – pore volume of water; $s_o+s_w=1$, в – mineralization, $\omega=\omega(c,s_w)$ – clay water absorption coefficient, $m=m(c,s_w)$ – porosity y, a – amount of absorbed salt, Д – diffusion coefficient, γ_{eff} – effective surface tension at the phase boundary, J – J. Leverett's function, l_x, l_y – width and length of the model, h – reservoir thickness, (x_j^P,y_j^P) и (x_i^I,y_i^I) – Coordinates j and i of the production and injection wells, t – time [61, 62].

In the system of equations (1)–(6) the independent unknown function is the pressure of the aqueous phase, the molar composition of the mixture, and the concentration of salts in the reservoir. To solve a system of equations (1)–(6) they need to be supplemented with equations of phase states [64]:

$$f_{i,w}-f_{i,l}=0,i=\overline{1,N},$$

$$x_{wi}V_w+x_{oi}(1-V_w)-z_i=0,i=\overline{1,N},$$

$$\sum_{i=1}^{N}x_{oi}-1=0,$$

where f_{iw}, f_{io} – the volatility of components in the oil and water phases is calculated using the equations of state of the phases [63]. The system (7) identifies the molar composition, density, viscosity, and mole fractions of each phase by changes in pressure, temperature, and component composition of the mixture.

Considering the following conditions:

$$\sum_{i=1}^{N} x_{oi} = \sum_{i=1}^{N} x_{wi} = 1, \sum_{i=1}^{N} z_i = 1.$$

Summing up the equations of the system (1) for all components we obtain the equation of conservation of mass of the oil-water mixture:

$$div\left\{kh\alpha \cdot gradp_w\right\} + div\left\{kh\alpha \cdot gradp_c\right\} + \\ + \sum_{j=1}^{n_1} \overline{Q_j}(t)\delta(x - x_j^I, y - y_j^I) = \\ = \frac{\partial}{\partial t}\left[mh\varphi\right], \overline{Q_j}(t) = \sum_{i=1}^{N} Q_i^j(t)\ldots \tag{7}$$

In this case, system (1)–(4) is equivalent to the following system:

$$div\left\{kh\alpha \cdot gradp_w\right\} + div\left\{kh\alpha \cdot gradp_c\right\} + \\ + \sum_{j=1}^{n_1} \overline{Q_j}(t)\delta(x - x_j^I, y - y_j^I) = \\ = \frac{\partial}{\partial t}\left[mh\varphi\right] \overline{Q_j(t)} = \sum_{i=1}^{N} Q_i^j(t)\ldots \tag{8}$$

$$div\left\{kh\alpha_i z_i \cdot gradp_w\right\} + div\left\{kh\alpha_i z_i \cdot gradp_c\right\} + \\ + \sum_{j=1}^{n_1} Q_i^j(t)\delta(x - x_j^I, y - y_j^I) = \\ = \frac{\partial}{\partial t}\left[mh\alpha z_i\right], \quad i = \overline{1, N}\ldots \tag{9}$$

$$div\left\{kh\alpha_{N+1} z_{N+1} \cdot gradp_w\right\} + \\ + \sum_{l=1}^{n_2} Q_{N+1}^l(t)\delta\left(x - x_l^P, y - y_l^P\right) = \\ = \frac{\partial}{\partial t}\left[mh\alpha \cdot z_{N+1} + h\omega\frac{\rho_{w0}}{M_w}\right]\ldots \tag{10}$$

$$div\left(ckh\lambda_w gradp_w\right) + \frac{\partial}{\partial t}\left[h\left(mcs_w + a\right)\frac{\rho_w}{M_w}\right] = \\ = div\left(Dgradc\right) + \sum_{l=1}^{n_2} cQ_{iw}^P(t)\delta\left(x - x_l^P, y - y_l^P\right)\ldots, \tag{11}$$

where

$$a_i = \frac{1}{1 + V_w\left(k_i - 1\right)}\left(\frac{f_o\rho_o}{\mu_o} + k_i\frac{f_w\rho_w}{\mu_w}\right),$$

$$\alpha = \left(\frac{s_o\rho_o}{M_o} + \frac{f_w\rho_w}{M_w}\right).\lambda_o = \frac{f_o\rho_o}{\mu_o M_o},$$

$$\lambda_w = \frac{f_w\rho_w}{\mu_w M_w},$$

$$\alpha_{N+1} = \frac{1}{1 + V_w\left(k_{N+1} - 1\right)}\left(\lambda_o + k_{N+1}\lambda_w\right).$$

Description of the numerical model

The presence of clay minerals contained in oil reservoirs at the Oil Dashlary field contributes to increased oil recovery, depending on the mineral content of the injected water. Consequently, depending on the conditions and properties of the formation, different mineral compositions and concentrations in the injected water are considered. The study is focused on block X of the Balakhani formation "Oil Dashlary". This field was put into operation in 1957 [60, 61].

In numerical simulation two-dimensional surfactant polymer injection was considered. The modeling was carried out on a model built in a Cartesian coordinate system, size 4000×2000 m, grid was $20 \times 1 \times 5$. The simulation has begun with injection during 1260 days followed by injection of a mixture of low-salinity water/polymer slug/polymer and surfactant within the next 1700 days.

In Fig. 2 the injection and production wells of one of the offshore fields of Azerbaijan have been modeled. Two wells were selected for numerical modeling: injection well No. 2430 (I-2430 in the numerical model) and production well No. 2560 (P-2560 in the numerical model). The saturation of the field with fluids is heterogeneous.

The properties of the model are shown in table 2.

The model did not include any production restrictions for the well, as well as pressure restrictions. In this work, we used for modeling MATLAB Reservoir Simulation Toolbox (MRST).

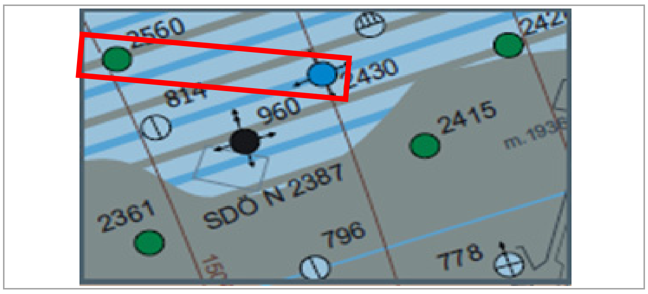

Fig. 2. Structural map of the "Oil Dashlary" field

Table 2

Properties of a numerical model [63]

Characteristic	Value
Model (length and width, m)	4000×200
Average permeability, mD	253
Average porosity	0,24
Temperature, °C	50
Pressure, bar	40
Density of oil in reservoir conditions, kg/m^3	883
Viscosity, sP	6,4
Clay content, %	40,1

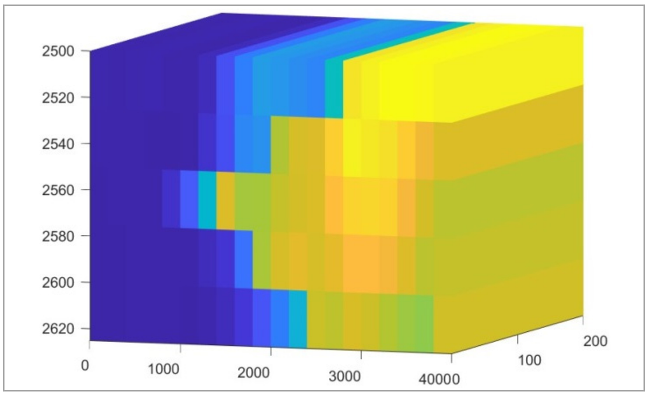

Fig. 3. Numerical sector model of the reservoir

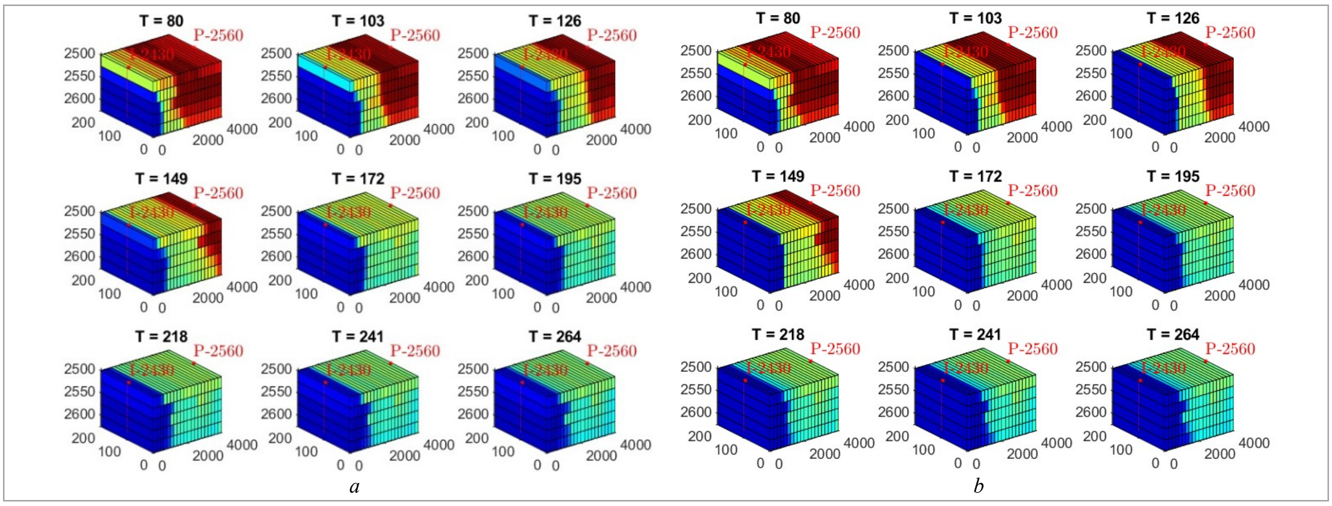

Fig. 4. Start-up scenario: *a* – basic; *b* – with flooding with water of 0.02 % mineralization (salinity)

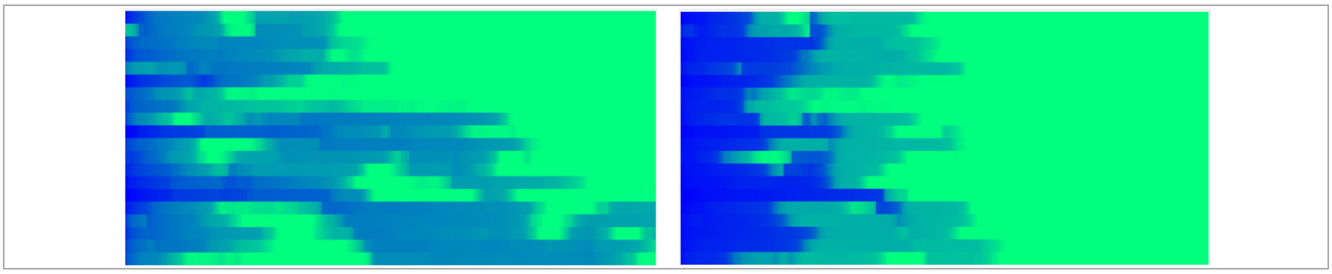

Fig. 5. Shoreline Advancement in the Baseline Flood Scenario and in the case of flooding with water with a mineralization of 0.02 %

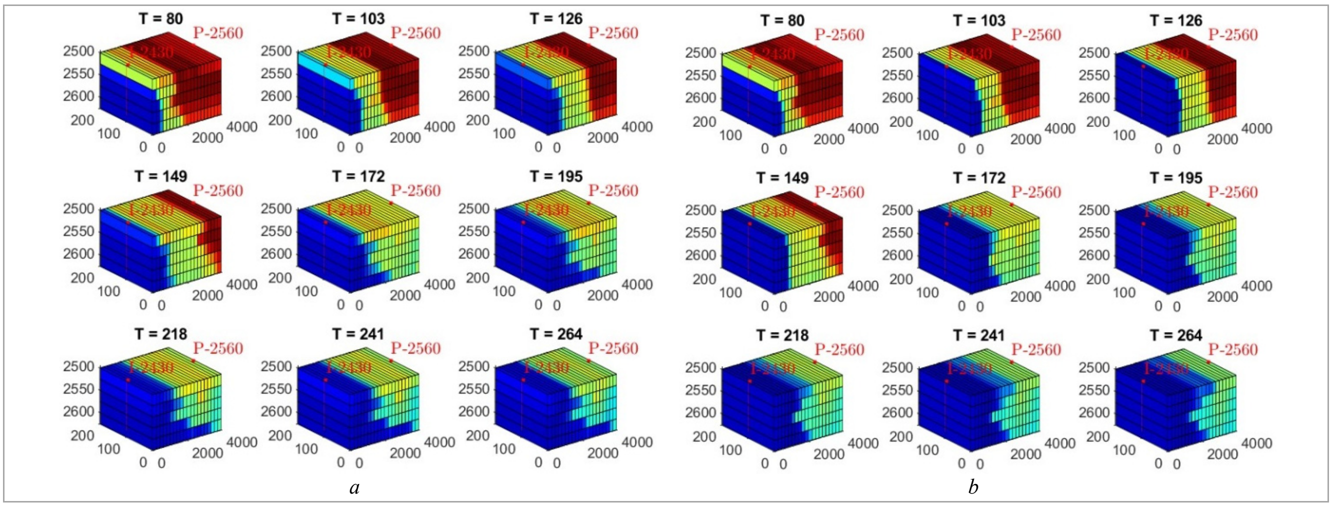

Fig. 6. Flooding scenario: *a* – polymer; *b* – surfactant – polymer

Table 3

Case study results

Case studies	Oil production, thousand tons	Recovery rate, %	Increase in RF compared to with the baseline scenario, %	Additional oil production, thousand tons
Basic variant	157,428	22,2 %	–	
Water flooding with salinity	185,288	26,1	3,9	27,860
Polymer	199,350	28,1	5,9	41,922
Surfactant polymer flooding	221,316	31,2	9,0	63,888

Results

A numerical sector model of the reservoir is shown in Fig. 3.

4 cases were analyzed in the study:

• basic scenario with typical salinity of injected water, implemented in Azerbaijan;

• water flooding with a salinity of 0.02%;

• polymer flooding;

• Surfactant-polymer flooding.

The results are visualized below for different time periods (Fig. 4).

Figure 5 below shows a cross-section of the model with a base case scenario and water flooding with a salinity of 0.02%. Based on the above calculations, we can conclude that the volume of displaced oil is higher when displaced by mineralized water.

Figure 6, *a*, shows the results of polymer flooding.

As can be seen from Fig. 6, *b*, the highest oil recovery with the lowest residual oil saturation is achieved with polymer flooding.

The simulation results are given in Table 3.

Thus, the results obtained on the basis of the hydrodynamic model (1)–(7) show that increased oil recovery is achieved by changing the salt content of water, polymer flooding and surfactant-polymer flooding (Fig. 7).

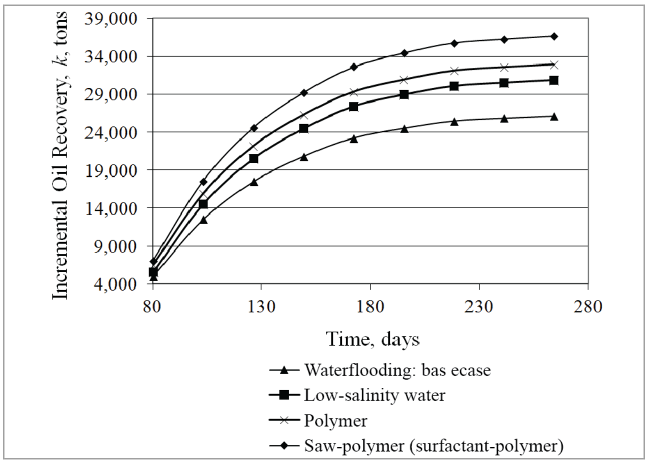

Fig. 7. Dependence of oil production growth from the mineralization of water injected into the reservoir words: low-salinity water; polymer; saw-polymer (surfactant-polymer)

It is worth noting that reservoir heterogeneity plays a role in the advancement of the displacement front. Various reservoir characteristics, such as permeability and porosity, can affect the movement of low-salinity water, polymer flooding, and Surfactant-polymer flooding.

Collectors with high permeability are particularly suitable for polymer flooding, as they have less negative effects on adsorption. The presence of a non-uniform distribution is advantageous for enhanced oil recovery, as the injected fluid (water or polymer) is forced to pass through both low and high permeability zones, resulting in higher production rates.

The presence of significant heterogeneity in the reservoir leads to increased adsorption, and the reason for this is the presence of flow limitations.

The SAW-polymer flooding system demonstrates high efficiency and leads to an additional increase in oil recovery.

Conclusion

The study shows that waterflooding variants with mineralized water, polymers and surfactant-polymer flooding can be considered as a key strategy in enhanced oil recovery at a particular field. With a salinity of 0.02 %, production amounted to 26.1 %, while flooding in the basic version provided oil recovery of 22.2 %. In comparison, polymer flooding and polymer surfactant flooding resulted in recovery of 28.1 % and 31.2 %, respectively.

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