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PhD Thesis

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Development and application of new methods for intensification of oil production based on gas release in reservoir conditions

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ABSTRACT

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DEVELOPMENT AND APPLICATION OF NEW METHODS FOR INTENSIFICATION OF OIL PRODUCTION BASED ON GAS RELEASE IN RESERVOIR CONDITIONS

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GENERAL DESCRIPTION OF THE WORK

Relevance of the topic and level of development.

Currently, there is a consistent rise in the number of oil fields worldwide reaching advanced stages of development. Considering that the majority of Azerbaijan's oil fields were put into operation in the last century, this issue becomes particularly relevant for the country's oil and gas industry. In this context, the development and implementation of new methods to enhance reservoir recovery, allowing for the extension of the lifespan of existing fields, play a critically important role. It is important to highlight that despite the various methods available for enhancing oil recovery, many of them come with drawbacks and often exhibit a limited range of applicability, strongly influenced by the physic-geological conditions of the fields. Currently, in order to enhance the effectiveness of Enhanced Oil Recovery (EOR) methods, there is a growing trend towards employing diverse combinations of these methods. Nevertheless, even though the microbiological method stands out as one of the most versatile and accessible means for improving reservoir recovery, the improvement of this technology remains relatively underexplored.

Despite the abundance of successful field tests and its initiation since the 1950s, the widespread application of foam systems to enhance the oil recovery factor has not been achieved to date. The main obstacle is the challenging predictability of the foam systems' stability under reservoir conditions.

In this regard, the most challenging issue in the global oil industry, including the oil sector of the Republic of Azerbaijan, lies in the enhancement of reservoir oil recovery through the implementation on innovative technologies to increase oil extraction.

Tertiary methods to enhance reservoir oil recovery are typically categorized into distinct groups: thermal, physical, hydrodynamic, and chemical methods. Each subgroup includes its own set of advantages and disadvantages. Nevertheless, as the reservoir's resources are depleted, the application and refinement of these methods become crucial for extending the field's operational lifespan.

Currently, about half of the world's increased oil production results from the application of chemical and gas methods for enhanced oil recovery. This is attributed to their relatively high economic profitability, environmentally friendly nature, and the availability of the agents used. Although the development and improvement of technologies within these categories are very important for the oil and gas industry, there is still a lack of comprehensive exploration, including:

1. The application of gaseous biosystems in the subcritical phase state.
2. Application of self-foaming biosystems to align the displacement front.
3. Prevention of scale deposition within the reservoir by modifying the physicochemical properties of the injected water based on the pH of the reservoir water.
4. Mitigation of scale deposits arising from reservoir flooding using industrial production waste.

Object and subject of the research.

The object of the research oilfields that are in the late stage of development.

The subject of the study includes the application of gaseous biosystems in the subcritical phase state, application of self-foaming biosystems to align the displacement front, prevention of scale deposition within the reservoir by modifying the physicochemical properties of the injected water based on the pH of the reservoir water and Mitigation of scale deposits arising from reservoir flooding using industrial production waste.

Purpose and objectives of the study

The main goal of the study is the development and application of new methods for intensifying oil production based on gas release in reservoir conditions.

Main objectives of the study

– Study of carbonated biosystems in the subcritical region for the intensification of oil production;

– Investigation of foaming systems for deep diversion of the displacement front;

– Development of a method preventing precipitation of inorganic salts in the reservoir;

– Development of a method for increasing the efficiency of the waterflooding process in a heterogeneous reservoir.

Methods of research. The objectives were achieved through theoretical, experimental and field studies.

Basic provisions presented for defense:

1. A method for reservoir development based on displacing oil with gas-saturated biosystems in the subcritical region;

2. A method for developing an oil deposit that ensures deep diversion of the displacement front using a self-foaming system;

3. Methods for the development of a heterogeneous reservoir during flooding, based on precipitation and peptization effects.

Scientific novelty of the research

1. A method for the development of an oil deposit is proposed, based on the displacement of oil by gaseous biosystems in a subcritical region;

2. A method for the development of an oil deposit is proposed, which provides deep leveling of the displacement front using a self-foaming system;

3. Methods for the development of a heterogeneous reservoir during waterflooding based on the effects of sedimentation and peptization are proposed.

Practical significance of research

The oil field development method was successfully tested on wells No. 1798 and No. 2043 of the NeftDashlari oilfield. Following the implementation of the proposed method on the field's wells during an industrial test, there were noticeable improvements in oil production and a reduction in water production. In total, over a span of three months, an extra 300 tons of oil were successfully obtained.

The efficiency of a technique for preventing scale deposition was assessed on wells No. 367 and No. 645 within the Oil and Gas Production Department, named after N. Narimanov. Following the application of this method, both wells demonstrated an augmentation in oil production rates and extended intervals between maintenance activities. As a consequence of this trial, an extra 120 tons of oil were successfully extracted.

Eurasian patents №038892 approved on 03.11.21 and № 041040 from 31.08.2022 have been obtained for ways of developing oil deposits. Another patent, Eurasian patent №042065, obtained on 01.02.2023, focuses specifically on the prevention of salt deposition. Lastly, Eurasian patent №042822, acquired on 03.28.2023, is centered around the development of non-homogeneous layers within oil deposits.

Approval of the work.

Dissertation materials were reported and discussed at:

- V International Scientific and Practical Conference "Readings of A.I. Bulatov" (March 3, 2021);
- SPE Annual Caspian Technical Conference and Exibition, Baku, Azerbaijan (October 5-7, 2021);
- International Conference "Oil and Gas Energy", г. Ivano-Frankivsk, (September 21-24, 2021);
- VI International Scientific and Practical Conference "Readings of A.I. Bulatov" (March 31, 2022 г.).

Publications.

A total of 14 works were published based on the materials of the dissertation, comprising 6 articles, 4 conference papers, and 4 Eurasian patents.

The name of the institution where the dissertation work was performed.

Dissertation work was performed at “OilGasScientificResearchProject” Institute of State oil company of Azerbaijan Republic.

The total volume of the thesis with a separate indication of the individual structural parts of the thesis. The dissertation consists of an introduction, three chapters, the first chapter consists of 63 pages, the second - 64 pages, the third - 11 pages, includes 187794 characters, 6 figures, 16 graphs, 14 tables, a list of references, including 142 titles and 2 appendices.

BRIEF CONTENT OF THE WORK

In the introduction the significance of the dissertation project has been confirmed, the purpose, main research tasks, scientific novelty have been determined and its practical value has been clearly established.

The first chapter of the dissertation presents a literature review of the existing methods for oil production intensification based on gas release in the reservoir. Various techniques have been developed with the primary objective of enhancing oil recovery and augmenting the quantity of oil extracted from reservoirs. While each method exhibits its distinct advantages and drawbacks, practical applications often involve a synergistic combination of these techniques. A comprehensive examination of global indicators for enhanced oil recovery methods revealed that thermal, chemical, and gas methods continue to dominate the industry. In this regard, it is promising to develop methods for enhanced oil recovery based on the use of chemical reagents and gas generation in the reservoir.

Many scientists and engineers in the oil and gas industry, both in Azerbaijan and abroad, have been involved in the development of enhanced oil recovery methods. Among the researchers and scholars whose works have made significant contributions to the study of technologies for increasing oil and gas production are A.Kh. Mirzadzhanzade, M.T. Abbasov, G.I. Jalalov, A.M. Mamed-zade, B.A. Suleymanov, G.M. Panakhov, and others

A study reviewing methods to intensify oil production through gas release in reservoir conditions highlighted the potential for further exploration in this domain. An analysis of microbiological influence methods demonstrated their high efficiency, feasibility, and environmental acceptability. In light of these findings, a crucial research objective is to enhance microbiological technologies by using production waste. Furthermore, the development of a reservoir stimulation technique involving foaming to deeply displace the front of the oil displacement process in reservoir conditions will enhance field development efficiency [1].

The filtration properties of the bottomhole zone exhibit significant differences compared to the formation properties. During well operation, the characteristics of the bottomhole zone undergo changes due to the precipitation of inorganic salts, asphaltenes, resins, and paraffins. Additionally, weakly cemented rock particles are removed, leading to clogging, deformation, and rock destruction. The injection of seawater, which is incompatible with the formation brine, results in the deposition of inorganic deposits in surface equipment, tubing, and within the reservoir. Methods aimed at restoring and enhancing well performance focus on reducing the skin effect, increasing well productivity, achieving a balanced fluid inflow profile, and restricting water inflow into the well, among others.

Despite notable advancements in developing theoretical foundations and implementing various technologies to influence the bottomhole formation zone, the success rate of these endeavors remains insufficient. Traditional deposit control methods do not offer complete protection in systems prone to severe scale buildup. Many of the reagents used are ineffective. Consequently, the objective of this study is to explore and develop cost-effective compositions that effectively intensify oil production and prevent deposits in the reservoir.

The second chapter presents new methods for intensifying oil production based on gas release in reservoir conditions.

Studies indicate that the implementation of the microbiological stimulation method leads to the formation of oil-displacing agents within the reservoir and the generation of a considerable volume of gases, with carbon dioxide being the predominant gas produced.

The research paper explores both the theoretical and practical aspects of obtaining and utilizing stable biosystems in subcritical regions (SR) to enhance oil production. It also investigates the necessary conditions for implementing SR under reservoir conditions

[2,11]. It has been established that carbonated systems in SR have better oil-displacing properties than non-carbonated systems. The slip effect determines the behavior of gasified liquids in the SR under reservoir conditions. In this case, the slip effect is more pronounced, the smaller the average radius of the pore channel. In this regard, in an inhomogeneous porous medium, the filtration profile of carbonated liquids in the SR is expected to be more uniform than that of degassed liquids.

Under controlled laboratory conditions, studies were conducted to examine the intensity of gas generation using Zongen apparatus. Maximum gas generation occurs in a biosystem consisting of molasses and active sludge at a 1:1 ratio. In this experiment, 30.00 Nm^3/m^3 of gas was formed after 26 days. During fermentation, the average composition of the released gas is as follows: CO2-60%, N2-22%, CH4-14%, H2-4%. The solubility of a gas mixture in a liquid is calculated using Henry's law.

Let us consider the conditions for the formation of SR in the reservoir. It has been established that SR in gaseous liquids occurs in the pressure range 1.1-2.0 times higher than the saturation pressure. In this case, the SR of the displacing carbonated liquid does not necessarily have to begin at the bottom of the injection well but may begin somewhat deeper in the formation at some distance from the bottom.

It has been determined that to obtain a single-phase mixture, the bioreagent must be mixed with water, the volume of which in a unit volume of the mixture is determined by the formula [1]:

$$V_{в} = (1 - \frac{\Gamma}{Q}) \tag{1}$$

where Γ is the amount of gas dissolved in 1 m^3 of water, nm^3/m^3, Q is the volume of gas released from 1 m^3 of the biosystem.

To optimize displacement efficiency, the incorporation of surfactants and polymers into water presents an avenue for forming hybrid biopolymer systems. The solubility of a liquid can be controlled by introducing electrolytes, leading to a reduction in gas solubility. Furthermore, the addition of gas-evolving agents to the system can increase the released gas quantity if desired. This adaptation enables the utilization of biosystems at elevated reservoir pressures.

It should be noted that a long process of gas release from biosystems makes it possible to form SR not near the bottomhole zone, but in the depth of the formation, which contributes to a better leveling of the filtration profile and an increase in the displacement efficiency.

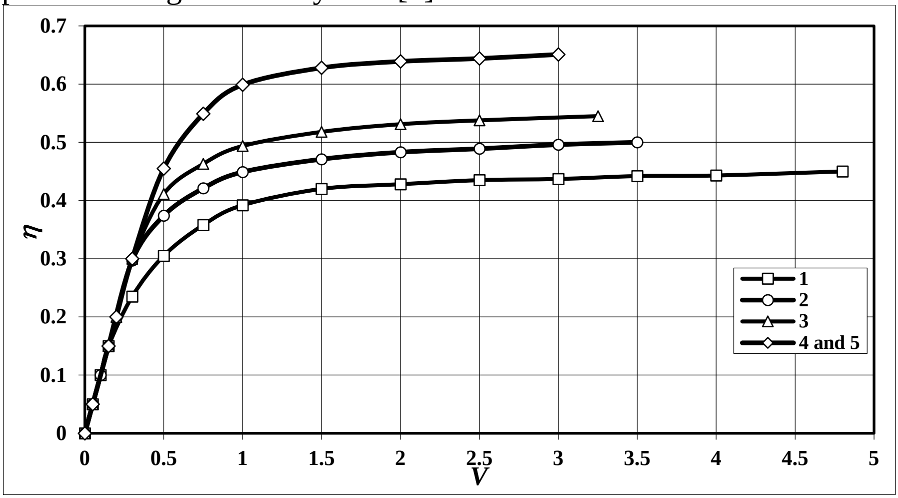
The implementation of the SR conditions depends on the ratio of the bottomhole pressure to the saturation pressure and the contour pressure during the filtration of carbonated fluid in the radial formation. In case the bottomhole pressure is not lower and close to the saturation pressure, and the contour pressure exceeds the bottomhole pressure by no more than 2 times, SR is implemented in almost the entire space from the supply contour to the well. When the bottomhole pressure significantly exceeds the saturation pressure, SR is practically not implemented.

The study of the displacement process was carried out through an experimental setup, simulating a layered-heterogeneous reservoir with interconnected interlayers. The gaseous biosystem under examination was prepared within a high-pressure vessel. In various experiments, the molasses-activated sludge system was combined with either water or a polymer solution (0.02% PAA aqueous solution) in proportions determined by formula (1). Under the specified thermobaric conditions (T = 303K, P = 2MPa), a homogeneous gas solution was achieved within a duration of seven days.

The displacement of the oil model was carried out by the following biosystems: a degassed biosystem, a gaseous biosystem, a degassed biopolymer system, and a gasified biopolymer system. The experimental results are shown in Graph1.

According to the experiments results, there is a noticeable increase in both water-free and final recovery factors (by 10% and 14%, respectively) when using a gasified biosystem instead of a degassed one. At the same time, there is a significant reduction in the volume of the pumped biosystem in the SR until the watercut of the effluent becomes 100%.

When using a gasified biopolymer system, there is an increase in the water-free and final recovery factors of 13% and 17% compared with a degassed biopolymer system, an increase of 20% and 30% compared with a gasified biosystem, and an increase of 25% and 44% compared to a degassed biosystem [4].



Graph 1. Dependence of the displacement coefficient (η) on the relative pore volume of pumping (V): 1 - degassed biosystem; 2 - gasified biosystem; 3 - degassed biopolymer system; 4 - gasified biopolymer system and 0.03% polyacrylamide (PAM) solution.

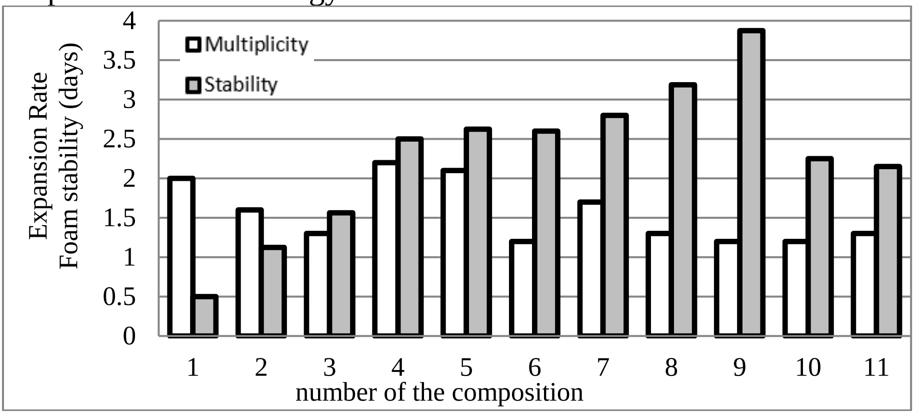
Compared with gasified polymer solutions, an increase in the PAM concentration does not lead to an increase in the displacement efficiency. This is explained by the fact that, in the process of displacement with a gasified biopolymer solution, two processes take place: with an increase in the concentration of PAM, the viscosity of the displacer increases, and the slip effect decreases because the wettability of the porous medium increases. At the same time, when gasified polymer solutions are used, the consumption of expensive polymer is significantly reduced. Indeed, the displacing efficiency of the biosystem after holding with the addition of PAM at a concentration of 0.02% is equal to the displacing efficiency of an aqueous solution of PAM at a concentration of 0.03% (see Graph. 1).

The positioning of the blocking screen within a highly permeable interlayer plays a crucial role in deep diversion of the liquid. This work aims to develop formulations for blocking the high permeability regions using cost-effective, readily available chemical reagents and to determine the dependence of the position of blocking screen on the degree of waterflooding of the reservoir for the purpose of achieving the maximum displacement efficiency. In this application, it is proposed to use a foam system generated under reservoir conditions.

The possibility of forming a foam rim system under reservoir conditions via the sequential injection of foaming and gas-producing solutions and their subsequent expansion by water injection. The foaming agent consists of an aqueous solution of a polymer (Carboxymethyl cellulose), and a foaming surfactant (Alkylbenzene sulfonate), while the gas-releasing agent is a biosystem consisting of waste from food processing (aqueous solution of milk whey) and a crosslinker (aluminum potassium sulfate).

Decomposition of the biosystem produces gases in the formation. Gas formation under reservoir conditions, together with a foaming surfactant, ensures foam generation. The bioreagent adjusts the required pH value and maintains the foaming ability of the surfactant for an extended period. The surfactant provides bonding of the formed gas bubbles and the formation of foam. The polymer slows down the flow of liquid on the surface of the bubble, ensuring high stability of the foam system, while the crosslinker, by structuring the polymer molecules, helps to increase the stability of the foam system, giving it mechanical strength. The presence of a polymer and a crosslinker improves the stability of the foam system by facilitating the formation of a stable gel film on the surface of the bubbles [7,14]. Continuous release of gases from the resulting microbiological processes ensures the formation of a self-foaming system with good stability.

Several tests were carried out under laboratory conditions to study the intensity of gas generation using the Songen apparatus. The stability and expansion ratio of the foam system are shown in Graph 2. It was established that with increasing concentration of the bioreagent and increasing generation of gas, the rate of foam production tended to increase. As the concentrations of the surfactants, polymers, and crosslinker increased, the stability of the respective foam solutions also increased. A further increase in the concentrations of the surfactants and polymers increased the viscosity of the foam, making movement in the formation increasingly difficult and leading to a rise in reagent costs. Thus, the foam compositions for No 4–9 (Graph 2) were judged to be stable enough for implementation of the deep diversion technology.



Graph 2. Expansion rate and stability of the investigated foam systems.

As the pressure rises, the stability of the foam also increases. At the same time, the stability of the foam at 10 MPa was 297 times higher than the stability at atmospheric pressure. Additionally, with a rise in pressure, the dispersion of the foam bubbles increases, whereas their size decreases.

For further research, the most indicative compositions were selected: 1 - high multiplicity, low stability (low values of surfactant, polymer and crosslinker additives, high - bioreagent); 5 - high multiplicity and stability (average values of surfactant, polymer, crosslinker and bioreagent additives); 9 - low multiplicity, high stability (high values of surfactant, polymer, crosslinker and bioreagent additives).

According to microphotographs, at low values of the foaming and gas-releasing reagents, bubbles of large size (~100 μm) and low density were formed; at medium values, bubbles of medium size (~10 μm) and high density were formed; and at large values, bubbles of small size (~1 μm) were formed.

The rheology of the foaming and gas-releasing solutions, as well as their mixtures at a ratio of 1:1 for the composition No.9, was explored. The rheology of the gas-releasing solution corresponds to Newtonian behavior, the foaming solution corresponds to pseudo-plastic behavior, and the mixture (foam system) corresponds to a dilatant liquid. It is known that a dilatant fluid, in contrast to a pseudoplastic fluid, promotes a leveling of the filtration profile and an increase in reservoir coverage.

An analysis of the implemented rheological scenarios shows that an increase of expansion (gas saturation) decreases the viscosity of the foam, and an increase in the polymer concentration, by contrast, increases the viscosity of the foam. Moreover, an increased polymer concentration significantly increases the stability of the foam system. All above mentioned properties allow creating of a stable foam system with adjustable rheological properties.

The study of the displacement process was carried out on an experimental setup. Composition №. 5 was used as a generator of the foam system. At the same time, under the indicated thermobaric conditions (T = 303 K, P = 1 MPa), we obtained the necessary foam system within four days.

In the first set of experiments, after full watering of the reservoir model (simulation of the impact on a highly watered formation through an injection well), a foaming solution, followed by a gas-releasing solution in equal volumes, was supplied to the inlet. The model was then closed for 4 days to generate a foam rim system. At the end of that time, water was supplied to the model input resulting in the displacement of the residual oil.

In the second series of experiments, all other conditions being held constant, the rim formation of the generated foam system at the depth of the reservoir model was achieved by injecting a kerosene rim equivalent to an amount of 10% of the pore volume between the foaming and gas-forming solutions.

In the third series of experiments, all other conditions being held constant, a gas-releasing solution was supplied to the model output, followed by a foaming solution (simulation of the impact on the bottom-hole zone of a responding production well).

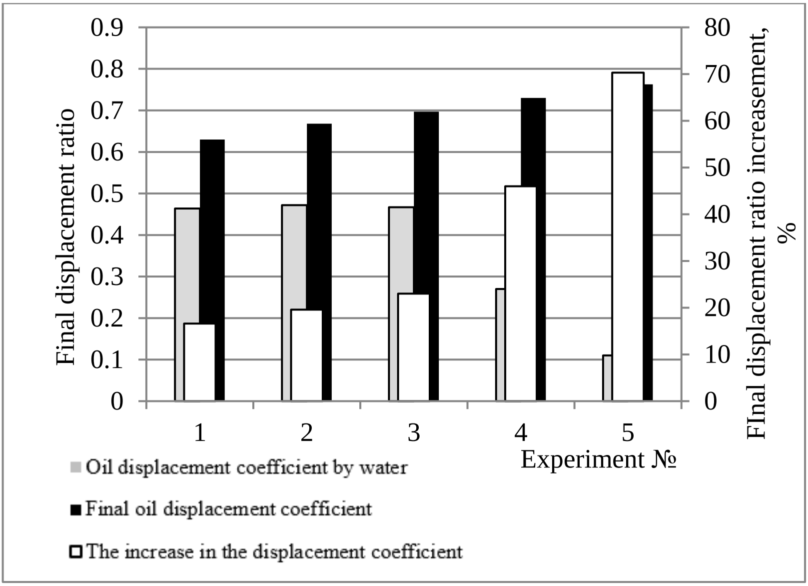
The fourth set of experiments simulated the impact on a layered heterogeneous reservoir with 50% of watering. At the same time, the rim formation of the generated foam system at the depth of the reservoir model was achieved by injecting a kerosene rim equivalent to an amount of 10% of the pore volume between the foaming and gas-forming solutions.

The fifth series of experiments demonstrated the utility of the reservoir model immediately after the water breakthrough. At the same time, a foaming solution was supplied to the reservoir model output, followed by the supply of a gas-releasing solution in equal volumes. The results are presented in the Graph 3.

Based on the results of the oil displacement experiments (series 1–3), it may be concluded that with full watering of the reservoir, the most promising outcome is the isolation of water inflows in the production well. The increase of the displacement ratio, in this case, is 23% compared to 16.6 and 19.6 for isolation near the injection line and at the deep deviation of the injected fluid, respectively.

With 50% watering, a deep diversion of the injected fluid causes an increase in the displacement ratio to 46%. When this technology was applied immediately after the water breakthrough to the production well with foam being generated near the injection line, the increase in the displacement rate was 70.3% [8].

Based on the data obtained, it is proposed that application of more viscous stable foam systems during the foam generating process near the injection line (composition №. 9) and less viscous stable foam systems (composition №. 5) are optimal for implementing the deep diversion of the fluid.



Graph 3. The results of experiments on oil displacement by foam systems in a layered heterogeneous reservoir.

To improve the efficiency of the water flooding process, a method for developing a heterogeneous reservoir is proposed, which includes isolating watered zones, preventing salt deposition directly in the reservoir, increasing the displacement coefficient by changing interfacial tension, wettability, and rock permeability.

The method involves introducing chemical reagents into seawater and subsequently injecting it into the reservoir through injection wells. The chemical reagents used in seawater include an acidic solution, alkaline waste, isopropyl alcohol, and a CMC (carboxymethyl cellulose) solution.

In the proposed method for developing a heterogeneous reservoir, a plume of seawater is injected into the reservoir containing alkaline formation water. As the injected seawater advances through the flushed high-permeability zones, it comes into contact with the alkaline formation water. As a result, insoluble salts precipitate, which plug the highly permeable watered zones. Subsequently, seawater with the proposed mixture is injected. The injected mixture will move into the low-permeability oil-bearing zones, displacing oil towards the producing wells. The added mixture in seawater will prevent the process of salt deposition in the porous medium due to the mixing of waters with different chemical characteristics and increase the displacement coefficient [12].

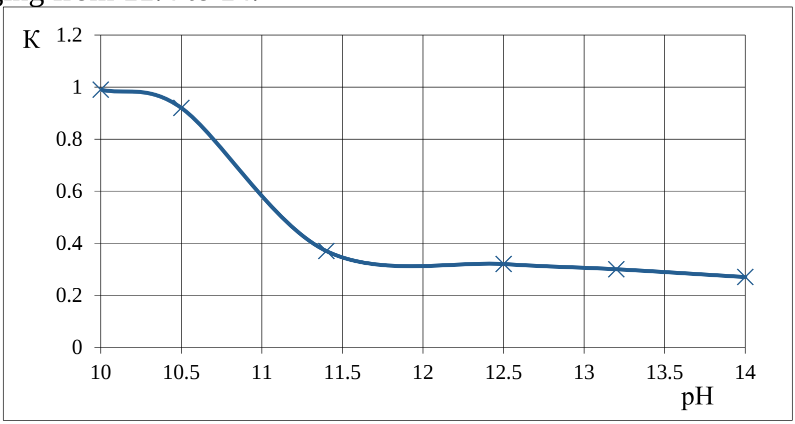
Treating the surface of the productive reservoir rocks with the proposed mixture reduces the interfacial tension at the "rock-oil-mixture" interface and promotes the adsorption of reagents on the rock surface by repelling the film of oil and hydrophilizing the surface. The addition of hydrochloric acid to the mixture will contribute to the dissolution of carbonate inclusions in the porous medium. It is known that hydrochloric acid is an effective peptizer. Unreacted hydrochloric acid will facilitate the process of converting insoluble precipitates into a colloidal or dissolved state.

If the reservoir contains acidic or neutral water, it is necessary to create a plume of alkaline water.

The effectiveness of the proposed composition was evaluated using a methodology based on the reagent's ability to retain Ca2+ cations in artificially prepared mineral waters of carbonate and sulfate types, which simulate the formation waters of oil fields. When using these compositions at a dosage of 40 mg/L, the protective effect of the proposed mixture reaches 90.8-96.0% in sulfate water and 94.1-98.1% in carbonate water. The maximum protective effect of the mixture is observed when using compositions with a dosage of 80 mg/L. In this case, the protective effect of the mixture in sulfate water is 96.3-99.8%, and in carbonate water, it is 97.2-100%. The active substance in the compositions ranges from 11% to 22.5%.

The research results demonstrate that in examples with a high concentration of the active substance, the inhibitory effect was high in both carbonate and sulfate water. This can be attributed to the high concentration of hydrochloric acid and the combination of alkaline waste, isopropyl alcohol, and CMC solution with a high mineral content. In compositions where the amount of CMC was high, the protective effect in sulfate water was higher. This is because the sodium salt of CMC, by blocking calcium and magnesium ions, prevents the formation of sulfate and gypsum deposits.

Further, experimental studies were conducted on reservoir models. Linear models with porous media were saturated with alkaline water at different pH values (ranging from 10 to 14), and the permeability to water was determined. Subsequently, seawater was filtered through the models. Afterward, the permeabilities of the porous media were re-evaluated using alkaline water, which saturated the pores of the respective model. Graph 4 shows the dependence of the final permeability of the porous media on the pH of the alkaline water. With a water pH of 11.4 and above, the effectiveness of plugging sharply increases. Therefore, in field conditions, it is advisable to inject a plume of water into the reservoir with a pH ranging from 11.4 to 14.



Graph 4 The dependence of the final permeability of the porous media on the pH of the alkaline water

For the next series of experiments, a layered-heterogeneous model with contacting layers was used. Oil was displaced from the model by alkaline formation water with a pH of 14. After complete displacement of the production from the model, seawater was injected. Following the injection of seawater, the flow rate of the pumped liquid decreased due to the precipitation formation in the high-permeability layer upon contact between seawater and alkaline formation water. This precipitation reduced the water filtration rate. Additionally, an increase in the final oil displacement coefficient by 2.6% was observed after the injection of seawater [13].

In subsequent studies, under the same conditions after the injection of seawater into the reservoir model containing alkaline formation water, seawater was injected with the addition of 0.5%, 1.0%, and 1.5% of the mixture, and its effect on the final oil displacement coefficient was investigated. The results of the experiments are shown in Table 2.

As seen from the table, when the mixture content in the water was increased to 1.0%, the increase in the displacement coefficient was 9.1% (Experiment 3). When injecting a 1.5% solution of the mixture in seawater (Experiment 4), a slight increase in the displacement coefficient of 9.3% was observed, but the rate of increase decreased. Therefore, the injection of a 1.0% solution of the proposed mixture in seawater was chosen as optimal.

When saturating the porous medium with acidic water, the injection of seawater will not result in precipitation (Experiment 5). In this experiment, the increase in the displacement coefficient was 3.5%.

To achieve the plugging of the high-permeability layer in the model containing hard or neutral water, alkaline water is injected before seawater (Experiment 6, 7). Then, a 1.0% solution of the proposed mixture in seawater is injected into the model. As a result of the experiments, the increase in the displacement coefficient in these experiments was 9.2% and 9.0% respectively.

To enhance the effectiveness of the method for preventing salt deposition directly in the reservoir by providing step-by-step cleaning of mineral deposits and increasing the displacement coefficient, further research was conducted.

Table 1

The impact of the proposed technology on the oil displacement coefficient

№	Reservoir water	The oil displacement coefficient	Injection of working agents	The final displacement coefficient	The increase in the final displacement coefficient %
1	Alkaline pH=14	0,463	Seawater (SW)	0,489	2,6
2	Alkaline pH=14	0,464	SW;0.5% solution of the mixture in SW	0,512	4,8
3	Alkaline pH=14	0,467	SW;1% solution of the mixture in SW	0,556	9,1
4	Alkaline pH=14	0,470	SW; 1.5% solution of the mixture in SW	0,563	9,3
5	Acidic pH=5	0,460	SW; 1% solution of the mixture in SW	0,495	3,5
6	Acidic pH=5	0,460	Alkaline water pH=14; SW; 1% solution of the mixture in SW	0,552	9,2
7	Neutral pH=7	0,461	Alkaline water pH=14; SW;1,0 % solution of the mixture in SW	0,551	9,0

In the proposed method, a mixture containing whey, sodium naphthenate, isopropyl alcohol, and a 0.5% aqueous solution of sodium CMC (carboxymethyl cellulose) salt is injected into the reservoir as a spacer in an amount of at least 5% of the pore volume of the reservoir. Subsequently, water injection is carried out to push the mixture further into the reservoir. Alternatively, the mixture can be added at a concentration of 1.5% to seawater and injected into the reservoir [10].

The injected mixture will prevent the process of salt deposition in the porous medium that occurs as a result of water mixing during the development of oil fields using water flooding methods. It will also prevent the mixing of water with different chemical characteristics during the flow from overlying reservoir layers.

The inclusion of alkaline waste in the mixture significantly reduces the interfacial tension at the phase boundary. The use of naphthenates in combination with aliphatic alcohols greatly enhances its inhibitory effectiveness. The anionic polymer, by blocking active calcium ions, prevents the formation of calcium sulfate and calcium carbonate. The acidic environment of cottage cheese whey and the various groups of active ingredients within it inhibit the formation of calcium carbonate and calcium sulfate, preventing nucleation. The presence of whey in the solution promotes the decomposition of carbohydrate compounds through microbiological processes and the formation of low-molecular-weight fatty acids, including acetic acid.

The advantage lies in the fact that the process of carbon dioxide and acid formation during the injection of the mixture containing whey is gradual and occurs directly in the reservoir. As a result, during the advancement of the solution to prevent salt deposition along the reservoir, a stepwise cleaning from deposits will be provided.

The effectiveness of the proposed method was evaluated using a methodology based on the reagent's ability to retain calcium ions in artificially prepared mineral waters of carbonate and sulfate types, which simulate formation water.

The effectiveness of the mixture is higher in carbonate water when the mixture contains a moderate percentage of whey and sodium

CMC salts and a low content of alkaline waste and isopropyl alcohol. The compositions of the mixtures in carbonate water, with a dosage of 40 g/ton, demonstrate an efficiency of 65-72%, with a dosage of 70 g/ton, the efficiency is 80-89%, and with a dosage of 100 g/ton, the efficiency is 93-100%. The effectiveness of the mixture compositions in sulfate water, at a dosage of 40 g/ton, is 60-69%, at a dosage of 70 g/ton, it is 70-84%, and at a dosage of 100 g/ton, it is 86-96%.

The method was tested under laboratory conditions using a linear layered heterogeneous reservoir model. Oil displacement from the model was carried out using an alkaline solution, and the oil displacement coefficient was determined. The results of the experiments are presented in Table 2.

In the first experiment, seawater was injected into the model. There was no increase in the displacement coefficient observed, but the liquid flow rate decreased by a factor of 2.64 due to the precipitation that occurred during the interaction between the alkaline and seawater.

In the second experiment, the proposed mixture was injected into the model at a volume of 4% of the pore volume, followed by water injection. In this experiment, there was a 1.5% increase in the displacement coefficient, and the liquid flow rate slightly decreased after the reagent injection. In the third and fourth experiments, the volume of the mixture injection was increased to 5% and 10% of the pore volume, respectively. As a result, a significant increase in the displacement coefficient was observed.

The increase in the displacement coefficient in the third experiment was 8.8%, and in the fourth experiment, it was 9.2%. The increase in the displacement coefficient occurs due to the reduction in interfacial tension and the mobility ratio between the displaced and displacing fluids, allowing the injected fluid to enter the low-permeability layer. The liquid flow rate remained unchanged in these experiments, indicating the absence of salt deposition in the porous medium.

Table 2

The results of experimental studies on linear reservoir models

№	The oil displacement coefficient	Injection of working agents into the reservoir model	The final oil displacement coefficient	The increase in the displacement coefficient, %
1	0,599	Seawater (SW)	0,599	-----
2	0.607	Coating – 4 % of the composition's pore volume, water	0,622	1,5
3	0,610	Coating – 5 % of composition's pore volume, water	0,698	8,8
4	0.605	Coating – 10 % of composition's pore volume, water	0,697	9,2
5	0.597	2.0% solution of the composition in seawater	0,626	2,9
6	0,612	1,5% solution of composition in SW	0,640	2,8
7	0,604	1 % solution of the composition in SW	0,616	1,2
8	0,62	0,5 % solution of the composition in SW	0,625	0,5

In subsequent experiments, seawater was injected into the model with the addition of 2.0%, 1.5%, 1.0%, and 0.5% of the proposed composition, respectively. As a result, the displacement coefficient increased by 2.9%, 2.8%, 1.2%, and 0.5% respectively, while the fluid consumption decreased. This indicates that the addition of the proposed composition to seawater prevents salt precipitation, and the displacement coefficient increases due to the change in surface tension and viscosity of the displacing agent (Table 2).

The results of the experimental studies have shown that it is advisable to inject the proposed mixture as a slug in a volume of at least 5% of the pore volume of the reservoir or add it at a concentration of 1.5% of the volume of seawater during water flooding. To prevent scale deposition in the near-wellbore area, a water solution of scale inhibitor is injected into the well. Furthermore, besides preventing scale deposition in the reservoir, prolonged contact of the produced solution with the wellbore during its operation leads to the cleaning of wellbore equipment from deposits.

In the third chapter of the dissertation, the results of pilot-scale and industrial-scale implementation of the developed technologies are presented.

Two wells, Well No. 1798 and Well No. 2043, located in the NeftDashlary field, were selected for conducting pilot-scale and industrial-scale tests of the developed self-foaming system.

The NeftDashlary field is characterized by complex geological structures and heterogeneity in reservoir properties. To maintain reservoir pressure, seawater and associated water are injected into the injection wells. As a result, the production wells located within the influence zone of the injection wells experience increasing water cut over time. Currently, the development of the field is facing significant decline in oil production and rising water cut in well production.

The selected wells were characterized by high water cut in the production. After implementing the intervention using the self-foaming biosystem, the average daily oil production increased in both wells, while the water cut in the well production decreased. The additional oil production from well 1798 during the period of April 12, 2022, to July 15, 2022, amounted to 120 tons, and from well 2043 during the period of March 23, 2022, to June 21, 2022, it amounted to 180 tons. Thus, the field trials on the two wells of the NeftDashlary field confirmed the efficacy of the developed self-foaming biosystem as observed in the laboratory research.

Indeed, the intensification of oil production in most fields is often accompanied by mineral salt deposition. The increase in water cut of the produced fluids, with a certain chemical composition, leads to a higher intensity of salt deposition.

The developed method for preventing salt deposition was tested on two wells, Well No. 367 and Well No. 645, at the N. Narimanov Oil and Gas Production Department. The formation of salt deposits in the reservoir matrix and in the pump-compressor pipes can significantly reduce well performance. To prevent salt deposition, a specially formulated aqueous solution was injected into the near-wellbore zone of the selected wells. This injected solution was subsequently carried into the wellbore during prolonged periods of well operation, effectively preventing salt deposition on the well equipment. By implementing this method, the negative impact of salt deposition on well performance was mitigated, allowing for improved operational efficiency and reduced maintenance requirements.

The water samples were collected before and after the implementation of the intervention. In the samples collected after the intervention, an increase in cations, anions, and mechanical impurities was observed. This indicates the effectiveness of the deposition inhibition process. The oil production rate in both wells increased, while the water cut decreased, confirming the success of the proposed method for preventing salt deposition.

As a result of the implemented intervention, the inter-repair period of operation on the wells doubled. Additionally, there was an increase in oil production, with an additional 120 tons of oil produced by the beginning of September 2022.

CONCLUSIONS

1. The theoretical and practical foundations have been developed for the acquisition and application of stable biosystems in subcritical region (SR) to enhance oil production.

- based on experimental research, it has been determined that the application of a gaseous biosystem contributes to an increase in the waterflood and ultimate displacement coefficients (by 10% and 14% respectively) compared to the degassed system.
- the possibility of effectively applying gaseous hybrid biopolymer systems has been demonstrated, with an observed increase in the waterflood and ultimate displacement coefficients by 20% and 30% respectively compared to the gaseous biosystem.
- it has been established that in cases where the bottomhole pressure is not lower and close to the saturation pressure, and the boundary pressure does not exceed the bottomhole pressure by more than 2 times, subcritical region is practically established throughout the space from the injection boundary to the well. However, when the bottomhole pressure exceeds the saturation pressure by more than 2 times, the SR is not practically implemented.

2. A technology for generating a stable foam system with adjustable rheological properties has been developed based on available classical reagents and biosystems. This technology ensures deep conformance control of the displacement front, allowing for efficient displacement of reservoir fluids.

- the required depth of penetration of the developed foam system to achieve maximum effectiveness has been determined for different levels of water saturation.
- it has been shown that in cases of high water cut (more than 90%), the most effective approach is to isolate the responsive producing wells, resulting in the final displacement coefficient 0.69;
- at a production water cut of 50%, significant improvements are observed when the injected fluid penetrates deeper into the reservoir. In this case, the value of final displacement coefficient is 0.73;

- the application of isolation near the injection line immediately after water breakthrough in producing wells yields the best results, with the final displacement coefficient in this case 0.76.

- it is proposed to use more viscous stable foam systems when generating foam near the injection line, and less viscous stable foam systems for achieving deep diversion of the injected fluid.

3. The proposed method for developing heterogeneous reservoirs involves isolating highly permeable, water-bearing zones through precipitation formation during the mixing of water with different characteristics. This method increases the displacement coefficient by altering interfacial tension, wettability, and rock permeability. It also facilitates the inhibition and peptization of insoluble precipitates.

4. A method has been developed to prevent scale deposition by creating a reactive mixture in the reservoir using production waste. With a dosage rate of 100 g/ton, this method achieves an efficiency of 93-100% in preventing calcium carbonate deposition and 86-96% in preventing calcium sulfate deposition.

5.The developed methods have been successfully tested and implemented in field conditions:

- the method of developing the oil reservoir based on isolating water influx into the well using foam systems has been tested on wells No. 1798 and No. 2043 of the "NeftDashlary" field. As a result of the field testing, an increase in oil production and a reduction in water cut were observed in these wells. Overall, an additional 300 tons of oil was obtained over a period of 3 months.

- the method of preventing scale deposition was tested on wells No. 367 and No. 645 of the N.Narimanov Oil and Gas Production Department. After the implementation of the method, there was an increase in oil production and an extension of the inter-repair period for these wells. As a result of the intervention, an additional 120 tons of oil was produced.

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