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Laboratory Results of the Influence of Carbon Dioxide on the Development of the Permo-Carboniferous Reservoir of the Usinskoye Deposit

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Результаты лабораторных исследований влияния диоксида углерода на разработку пермокарбоновой залежи Усинского месторождения

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As an option for enhancing oil recovery of a high-viscosity Permo-Carboniferous reservoir associated with the Usinskoye field, the use of technology based on technogenic carbon dioxide as an injection agent is considered. In the world practice, several fields are known the parameters of which are close to those of the Permo-Carboniferous reservoir and in which CO_2 injection was accepted as successful. Based on this, CO_2 injection can potentially be applicable in the conditions of a Permo-Carboniferous reservoir. At present, as a result of various development technologies implementation, reservoir zones are distinguished, characterized by different thermobaric properties. Depending on reservoir conditions, when displacing oil with gases, various modes of oil displacement can be realized.
This article describes the results of studies carried out to investigate the effect of carbon dioxide concentration on the properties of high-viscosity oil in the Permo-Carboniferous Reservoir of the Usinskoye field, as well as the results of filtration experiments on slim models produced to assess the oil displacement regime under various temperature and pressure conditions of the Permo-Carboniferous Reservoir. The study of the CO_2 concentration influence on oil properties was carried out using the standard PVT research technique. The displacement mode was assessed using the slim-tube technique.
Based on the performed experiments, it was established that an increase in the concentration of CO_2 in high-viscosity oil led to a noticeable change in its properties; for the conditions of a Permo-Carboniferous Reservoir, the most probable mode of oil displacement by carbon dioxide was established. Difficulties associated with the preparation of the CO_2-heavy oil system were described separately. Based on the literature review, it was shown that the rate of mixing of oil with carbon dioxide depended on certain conditions.

Ключевые слова:
высоковязкая нефть, повышение нефтеотдачи, диоксид углерода, пермокарбоновая залежь Усинского месторождения, коэффициент вытеснения нефти, лабораторные исследования, PVT, slim tube, асфальтены, вязкость, плотность, давление насыщения.

В качестве варианта повышения нефтеотдачи пермокарбоновой залежи высоковязкой нефти, приуроченной к Усинскому месторождению, рассматривается применение технологии, основанной на использовании техногенного диоксида углерода в качестве агента закачки в пласт. В мировой практике известно несколько месторождений, близких по своим параметрам к параметрам пермокарбоновой залежи, и на которых закачка CO_2 была принята успешной. Исходя из чего закачка CO_2 потенциально может быть применима в условиях пермокарбоновой залежи. В настоящее время, в результате реализации различных технологий разработки на залежи выделяются зоны пласта, характеризуемые различными термобарическими свойствами. В зависимости от пластовых условий при вытеснении нефти газами могут реализовываться различные режимы вытеснения нефти.
В данной статье описаны результаты исследований, выполненных с целью изучения влияния концентрации диоксида углерода на свойства высоковязкой нефти пермокарбоновой залежи Усинского месторождения, а также результаты фильтрационных экспериментов на слим-моделях, выполненных для оценки режима вытеснения нефти при различных термобарических условиях пермокарбоновой залежи. Изучение влияния концентрации CO_2 на свойства нефти выполнялось с применением стандартной методики PVT-исследований. Оценка режима вытеснения осуществлялась с применением методики slim-tube.
На основе выполненных экспериментов установлено, что увеличение концентрации CO_2 в высоковязкой нефти приводит к заметному изменению ее свойств, для условий пермокарбоновой залежи установлен наиболее вероятный режим вытеснения нефти диоксидом углерода. Отдельно описаны трудности, связанные с подготовкой системы «CO_2-тяжелая нефть». На основе обзора литературы показано, что скорость перемешивания нефти с углекислым газом зависит от определенных условий.

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Introduction

Today, the Permo-Carboniferous reservoir of the Usinskoye field uses a range of development technologies, namely, depletion, steam treatment, huff-and-puff treatment, and a combination of heat and chemical treatment [1]. Applying the technology based on using technogenic carbon dioxide as an injection agent is considered as a method to enhance oil recovery [2].

While developing and designing technologies of injecting gas agents into the rock for enhanced oil recovery, it is important to work out how the injection agent will interact with the reservoir oil, which will determine the efficiency of oil displacement. Dissolving carbon dioxide in high-viscosity oil significantly changes its properties. Therefore, before embarking on the research into estimating the efficiency of oil displacement by means of a gas agent it is necessary to conduct a PVT-study in order to evaluate the impact of the carbon dioxide concentration on oil properties.

When oil is displaced by carbon dioxide, depending on the reservoir conditions, oil composition, and the applied solvent, there may be various oil displacement scenarios [3] playing out as a result of various miscibility mechanisms [4]. One of the most effective laboratory methods to determine how the gas agent and oil are going to interact is the slim-tube method [5]. The slim-tube method facilitates the task of determining the gas-oil displacement scenario in given pressure-temperature conditions and settings that allow for the most optimal oil displacement using a gas agent. This method is also good for comparing different displacement agents and finding the right gas composition for a given field.

Below are the results of a PVT-study that was aimed at determining the impact of a given carbon dioxide concentration on the properties of the high-viscosity oil in the Permo-Carboniferous reservoir of the Usinskoye field, as well as the results of filtration tests using slim models to evaluate oil displacement scenarios in various pressure-temperature conditions of the Permo-Carboniferous reservoir.

Impact of CO_2 on the Physical-Chemical Properties of High-Viscosity Oils

One of the main factors affecting the efficiency of a given carbon dioxide injection technology for enhanced oil recovery is the drop in reservoir oil viscosity as it gets saturated with carbon dioxide [6]. High-viscosity oils with dissolved carbon dioxide demonstrate viscosity reduction rates comparable to those in case of heat treatment [7]. It is known that, with few exceptions, viscosity of liquids increases as their molecular weight grows [8]. In qualitative terms, the effect of reduced oil viscosity arising from the addition of any solvents (liquid or gaseous in standard conditions) can be explained by the reduction in molecular weight in comparison with that of primary oil. That said, even small solvent content in the mix causes a significant drop in viscosity [9]. Further increase of the solvent concentration decreases the mix viscosity but to a lesser extent. A similar effect is observed when oils get saturated with carbon dioxide [10–17].

Studies [15–17] show that as the content of CO_2 dissolved in oil rises, its density reduces. Particularly indicative are the results of the study [15] that points out the correlation between Wilmington field oil density and pressure for its saturated and unsaturated states. The density of degassed oil stood at 952.9 kg/m^3. At higher pressures the density of oil both saturated and unsaturated with carbon dioxide goes up. When oil is saturated with carbon dioxide, its density is reduced and at higher temperatures the difference in density between the saturated and unsaturated states increases. However, at 24 ºC and increasing pressure, the density of oil saturated with carbon dioxide exceeds that of unsaturated oil. The authors leave the finding without any comments assuming that it may indicate a flaw in the applied density measurement method or other subtle effects that come into play when oil is saturated with carbon dioxide at relatively low temperatures.

When carbon dioxide is dissolved in oil, it can give rise to formation of asphaltene deposits due to the reduced dispersion stability of asphaltenes in oil [18–21]. Carbon dioxide plays the biggest role in asphaltene precipitation compared with other gases. The amount of precipitated asphaltene rises as its molar fraction in oil keeps increasing. As the findings suggest [22], changing the concentration of carbon dioxide from 5 to 20 mol % in oil led to an increase in the amount of asphaltene deposits by 56 % at 14 MPa and 90 ˚C. Asphaltene precipitation begins only after the injected gas reaches certain concentration in the oil, which is defined as the asphaltene precipitation point. For example, when CO_2, associated petroleum gas, and nitrogen are dissolved in the heavy oil of Iran, the asphaltene precipitation points stand at 0.25; 0.28, and 0.5 mol % respectively (at 96 ˚C and 27.2 MPa) [23]. Asphaltene precipitation adversely affects oil recovery as it leads to a reduction in porosity and permeability, i.e. impairs the reservoir properties of productive formations.

The study conducted by A. K. Sharma et al. [24] that used the slim-tube method found that when the content of asphaltenes is at 13 % in the high-viscosity oil of the West Sak field (Alaska, USA), the oil displacement coefficient is reduced upon injection of above critical carbon dioxide due to the asphaltene precipitation in the reservoir. The asphaltene precipitation test showed that when oil displacement takes place in the presence of above critical CO_2, the oil loses 38 % asphaltenes, whereas in the presence of hydrocarbon solvents it loses 11–13 %.

Therefore, apart from reaching the miscible displacement scenario, one of the key conditions to get high oil displacement coefficients using carbon dioxide is keeping the asphaltene precipitation in the reservoir at its lowest.

Difficulties of the Experimental Study into the Properties of the CO_2 – Heavy Oil System

All isolated systems where temperature, pressure, concentration of particles, and other characteristics do not have equilibrium values, demonstrate spontaneous realignment processes that continue until the system returns to equilibrium. Thermodynamic equilibrium is a state of an isolated system when all internal processes stop [25].

The studies into the PVT properties of the CO_2 – high-gravity oil system fail to mention the difficulty of getting into the state of equilibrium. However, while studying the PVT properties of the CO_2 – heavy oil system, it is rather challenging to prepare samples of the mix of heavy high-viscosity oil and carbon dioxide.

The authors [10] claim that it takes a long time for the CO_2 – heavy oil system to reach equilibrium. The study assumed that the system reached equilibrium when pressure in the PVT cell started falling at a rate that was lower than 3.4 kPa per day. In most cases this state took around two weeks to settle.

The research [15] indicates that before the experiment was carried out it took a long while and much effort to select the right equipment for the task of ensuring full saturation of oil with carbon dioxide and retrieving viscosity and density data. The configuration of the system that was used in those studies differed from other PVT equipment in that the liquid (oil and CO_2) was circulating throughout the entire system to reach equilibrium. To run the liquid, the PVT system used a magnetic pump that could withstand the pressure of 34.5 MPa. To make for full and even dissolution of carbon dioxide, the oil and carbon dioxide circulated through the system for 48 hours.

It is known that at higher oil densities dissolution of gases goes down [26–28]. It can be assumed that it is hard to reach the state of complete mixing in the CO_2 – heavy oil system due to the reduction of the carbon dioxide dissolution coefficient at higher oil densities, so in order to ensure complete mixing at higher concentrations of CO_2 it should be done at high pressures. Comparing the correlations between saturation pressure and concentration of carbon dioxide for high-gravity oil from the Weyburn field [29] and the heavy oil from the Senlac field [10], it can be concluded that reaching equilibrium even at high concentrations of carbon dioxide around 50 mol % in the mix proves possible for oils with contrasting properties, while saturation pressures may be approximately the same for both kinds of oil. Therefore, increased oil density proves to have an insignificant effect on the dissolution of carbon dioxide in it.

The rate at which the CO_2 – heavy oil system comes into equilibrium with complete mixing may also depend on the viscosity of primary oil and the molecular diffusion coefficient. Overall, increasing viscosity of liquid hydrocarbons tends to lead to a decrease in the diffusion coefficient of carbon dioxide. The study [25] points to the dependence of CO_2 diffusion coefficient on viscosity of liquid, which confirms the above. However the values of diffusion coefficients are calculated for pure hydrocarbons and some types of oils and cover the range of viscosities from 0.2 to 100 mPa·s, and the samples may not be particularly representative as significantly different diffusion coefficients are attributed to the liquid viscosity values that are very close. Judging from the findings mentioned as an example below, extending the range of viscosities and expanding the data set may fail to confirm the claimed correlation between the diffusion coefficient and viscosity in similar thermodynamic conditions.

The studies [31, 32] quote the value of diffusion coefficient of CO_2 in Athabasca bitumen (density 1026 kg/m^3, dynamic viscosity $2 \cdot 10^6$ mPa·s) to be around 10^{-10} m^2/s at 21°C and 3.1–5.6 MPa.

The research [33] found the value of diffusion coefficient for carbon dioxide in high-viscosity oil with viscosity of 5000 mPa·s at 21°C and 3.5 MPa to stand at $4.8 \cdot 10^{-9}$ m^2/s.

The high-gravity oil from the Weyburn field with density of 877 kg/m^3 and viscosity of 13 mPa·s shows the diffusion coefficients in the range of pressures from 0.1 to 5.0 MPa at 27°C that vary within $0.47–2.49 \cdot 10^{-9}$ m^2/s [34].

The values of diffusion coefficient determined in the study [35] for carbon dioxide in pentane, decane, and hexadecane at 25 °C in the pressure range from 1.5 to 5.2 MPa stand at 10^{-9} m^2/s, which is 10 times higher than with bitumen.

As we see, the carbon dioxide diffusion coefficients do not differ significantly in oils with different physicochemical properties. Since the rate at which concentration changes when gas and liquid come into contact is directly dependent on the diffusion coefficient, when it changes by 2–4 times it may make a difference in case of complete miscibility without mixing the phases but it should not have a significant impact on reaching complete mixing in conditions of relatively intense mass transfer that occurs when samples of oil and carbon dioxide mixtures are prepared in the laboratory using PVT units that provide mechanical mixing by various means.

Regretfully enough, we failed to find sources that would describe, at least to some extent, the impact of oil viscosity on obtaining a uniform mix with carbon dioxide. Apparently, the duration of this process gets longer as oil viscosity rises. It is clear that at high flow rates the mixing process develops more intensively. However, at high flow rates and high viscosity of liquids, the conventional PVT equipment experiences respective pressure oscillations of around 5 MPa and more. The difficulty is that the researcher who controls the PVT unit cannot know in advance what pressure will saturate the CO_2 – heavy oil system, and with flows that have large differential pressure at a certain point in the hydraulic system of the PVT unit the pressure may be lower than the saturation pressure, which will render the complete mixing of oil and carbon dioxide impossible. This issue can be resolved by increasing the pressure in the PVT system to a certain high value that can exceed the reservoir pressure in the field of origin. Obtaining a uniform mix of oil and CO_2 in such conditions will likely affect its properties, so it cannot be stated with confidence that the resulting data may be used in further forecasting. Nevertheless, all ideas stated above are mere assumptions that require additional research.

Some authors use approaches that do not reach the complete mixing of carbon dioxide and heavy oil, and focus on studying the properties of two (or more) detected phases separately [36, 37]. It is problematic to carry out a critical review of such studies and work out the reasons of using such approaches because they fail to reveal the details of how the recombined sample mixtures of oil and carbon dioxide were prepared, which does not, however, indicate the lack of elaboration on the problem by the authors.

Technical Aspects of the Slim-Tube Method

It was ascertained by many researchers [38–43] that the value of oil displacement coefficient using slim tubes and, thus, further estimation of the gas-oil displacement scenario to a large extent depend on the conditions of experiments. The main significant parameters in the experiment are:

– slim tube length [39–41];
– slim tube diameter [39, 40];
– filler material (real rock, glass beads, etc.) [42];
– filler pore volume structure [42];
– displacement rate [39, 40];
– oil component composition;
– displacement gas purity (specifically CO_2) [42].

It is well-known that at increasing pressure and constant temperature carbon dioxide dissolves in oil better, which leads to an increase in the oil displacement coefficient. As the molecular weight of hydrocarbons shrinks, it enhances the CO_2 dissolution in them. In high-gravity oils, CO_2 dissolves completely at pressures 5.6–7.0 MPa. Heavy oil does not mix with liquid carbon dioxide without trace, forming insoluble residue made of heavy hydrocarbons.

The authors [43] note that the development of solvent miscibility based on CO_2 results from extracting the hydrocarbon components into a phase saturated with CO_2. Therefore, at preset temperature and oil composition, the solvent has to be pressurized hard enough to facilitate its solvent capacity.

With the temperature and average molecular weight of oil rising at constant pressure, the dissolution of carbon dioxide in oil drops, which results in a decrease in the oil displacement coefficient and a rise in the minimum miscibility pressure. The impact of reservoir temperature and pressure on the value of the oil displacement coefficient is well demonstrated in the study [5].

Description of Laboratory Equipment

The studies were conducted using a unit (PIK-PVT) that determines PVT properties of heavy oils and allows the research to be conducted in accordance with [44]. The unit is a set of equipment that includes:

– high pressure cells;
– capillary viscometer;
– digital density meter;
– double-plunger piston pumps,
– oven,
– personal computer with software to control the unit.

The filtration tests to determine how oil is displaced by carbon dioxide using the slim-tube method were conducted in a special-purpose laboratory complex. The complex configuration allows to carry out experiments that involve two- and three-phase filtration, as well as simultaneous performance of two independent tests, including those using the slim-tube method. The technical description of the laboratory complex and its specifications are presented in the research [45]. Table 1 gives the technical characteristics of the slim tube used in the studies.

Table 1

Technical specifications of the slim tube to define minimum miscibility pressure

Parameter	Value
Tube length, m	12
Tube outside diameter, mm	12
Material	Stainless steel
Porous material	Silica sand, grain size 100–500 μm
Porosity, %	54
Pore volume, cm^3	395

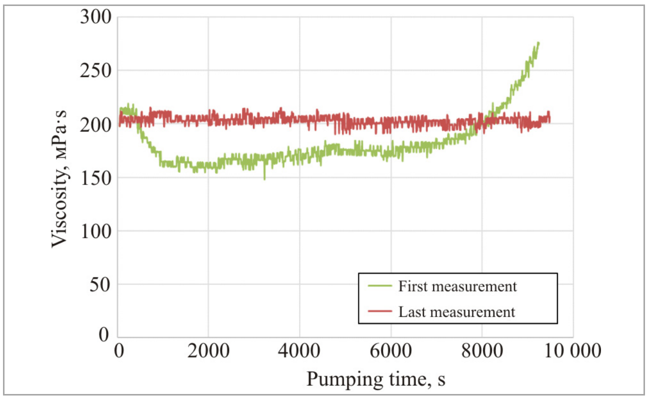

Fig. 1. Dynamic change in viscosity of the mix of the recombined oil model and carbon dioxide in the PVT unit

Study Description

The laboratory research was carried out in several stages: preparation of reservoir fluid models, PVT tests on the recombined models of reservoir oil and its mixes with carbon dioxide, and filtration tests to determine the oil displacement regime using carbon dioxide and the slim-tube technique.

While preparing the reservoir fluid models, recombined models of oil and its mixes with carbon dioxide were produced. This process used a wellhead sample of oil from the production wells of the Permo-Carboniferous reservoir of the Usinskoye field that was previously degassed and cleared of all mechanical impurities. A detailed description of the oil model preparation procedure is given in the study [45] published earlier.

The purpose of the PVT studies was to observe how the concentration of carbon dioxide in the Permo-Carboniferous reservoir oil of the Usinskoye field affects its physicochemical properties under various pressure and temperature conditions that resulted from using different treatment technologies aimed at the formation in different zones of the Permo-Carboniferous reservoir. Therefore, at this stage of the research various concentrations of CO_2 (1, 5, 10, 15 %) in the mix with the recombined oil sample were studied in terms of viscosity, density, and saturation pressure at different temperatures (23, 35, 150, and 200 ºC) and pressures.

The PVT properties of the Permo-Carboniferous oil mixes with carbon dioxide were determined in accordance with [44]. Additionally, correlations between the volume factor of oil and pressure were determined at different temperatures. The correlations were further used in the calculation of oil displacement coefficients using slim-models.

The regime of oil displacement with carbon dioxide is based on the value of the oil displacement coefficient in accordance with the following criteria. Namely, complete mixing is achieved at displacement of at least 90 % of oil. If the oil displacement coefficient is below 50–60 %, the displacement process is immiscible in nature. Reaching the transient displacement coefficient of 60–90 % indicates condition of partial mixing.

The detailed description of the experiment procedure applied to determine the Permo-Carboniferous reservoir oil displacement scenario in the Usinskoye field using the slim-tube technique is given in the research [45] published earlier. The filtration tests with slim-models were carried out at the same temperatures and within the same pressure range as at the stage of PVT tests.

Results and Discussion

During the studies it was observed that while preparing the mix of oil and carbon dioxide it took a considerable amount of time to put the heavy oil – CO_2 system into equilibrium. Figure 1 shows the dynamic change in viscosity of the mix of the recombined oil model and carbon dioxide (at 15 % mol. concentration) straight after the sample hits the PVT unit (first measurment) and after it reaches uniformity (final measurement). Each curve characterizes a change in oil viscosity in time as it is pumped from one measuring cell of the PVT unit into another through the capillary viscometer.

As Fig. 1 suggests, at the point of the first measurement there is a noticeable change in viscosity. At the same time, there are no spikes in viscosity, which points to the absence of several uniform phases with contrasting properties; rather, it is likely to be a single continuous phase with unchanged gas concentration in terms of volume. Further mixing revealed that the mix viscosity decreases during pumping. The mixing continued to the point when the viscosity values balanced out across the entire sample. That was how the uniform mix of high-viscosity oil and carbon dioxide was developed. It is worth noting that the sample preparation process depending on the carbon dioxide concentration took anywhere between a few days at minimum CO_2 1 mol. % concentration to three weeks at maximum CO_2 15 mol. % concentration. It took a similar amount of time to bring the mix of high-viscosity oil and carbon dioxide to uniformity as it was presented in the studies [10, 14].

The results of research into the impact of CO_2 concentration on the high-viscosity oil of the Permo-Carboniferous reservoir can be seen in Fig. 2–4. Fig. 2 shows the correlation between reservoir oil saturation pressure and the concentration of carbon dioxide dissolved in it.

As Fig. 2 suggests, the saturation pressure both rises with the increase of temperature and non-linearly rises with the growth of the carbon dioxide concentration. That said, as the temperature rises with steadily increasing CO_2 concentration it speeds up the saturation pressure growth rate. With the initial reservoir temperature standing at 23 °C and reservoir pressure of 9.2 MPa, the reservoir oil has a capacity to dissolve 17–18 mol. % CO_2. With the initial reservoir pressure and temperature of 150 °C, the volume of dissolved CO_2 is much lower, with the maximum concentration of CO_2 around 2 mol. %.

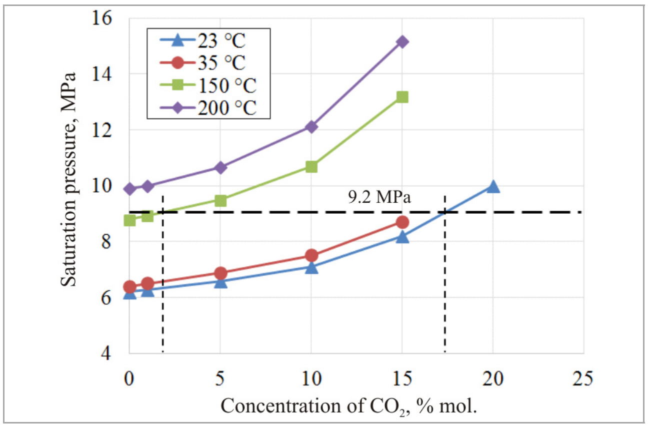

Fig. 2. Dependence of saturation pressure on carbon dioxide concentration at various temperatures

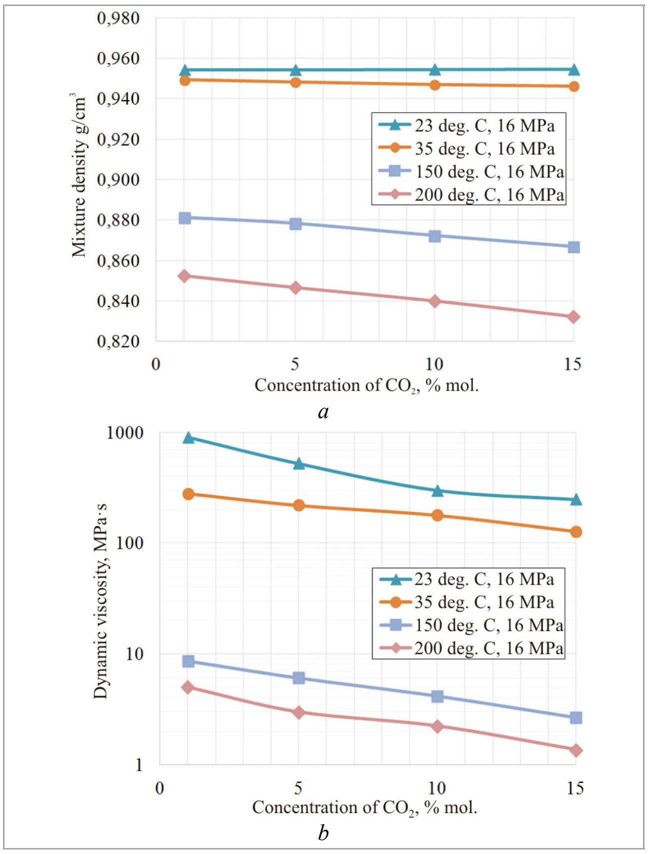

Fig. 3. Dependence of density (*a*) and viscosity (*b*) of oil on the CO_2 concentration at various temperatures and pressure of 16 MPa

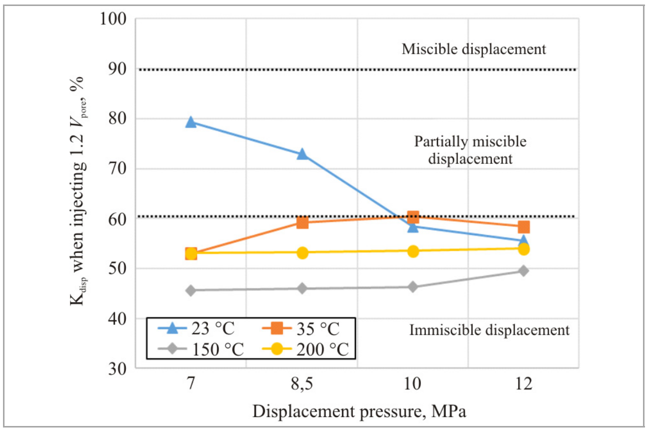

Fig. 4. Dependence of gas-oil displacement coefficients on displacement pressure at various temperatures

Fig. 3 depicts the correlation between the Permo-Carboniferous reservoir oil mix density and various concentrations of carbon dioxide at various temperatures.

According to Fig. 3, *a*, it is seen that dissolving CO_2 in the mix has negligible impact on the mix density at low temperatures (23° and 35 °C). As the temperature rises with the increasing mole fraction of carbon dioxide in the mixture, the density drops considerably, and the higher the temperature, the more considerable the difference in density.

Fig. 3, *b* shows the correlation between the Permo-Carboniferous reservoir oil viscosity at various concentrations of carbon dioxide and various temperatures.

As carbon dioxide dissolves in the recombined sample of reservoir oil, its viscosity significantly drops, which is shown in Fig. 4. As the concentration of CO_2 rises from 0 to 5 mol. %, viscosity shows a sharp fall. Further increased concentration of CO_2 from 10 to 15 mol. % leads to a less intensive decrease in viscosity (viscosity axis is represented in logarithmic scale).

The PVT tests found that only a small amount of CO_2 is dissolved in the Permo-Carboniferous reservoir oil, but even this insignificant presence of CO_2 in oil makes it possible to additionally reduce its viscosity.

The results of the estimated displacement scenario for the high-viscosity oil of the Permo-Carboniferous reservoir in the Usinskoye field are presented in Fig. 4 as per temperatures and pressures corresponding to different reservoir conditions.

The range of the studied pressure and temperature parameters did not reveal any miscible displacement of oil by carbon dioxide. At 23 °C, the oil displacement coefficient values were the highest (79 and 73 %) at pressures of 7 and 8.5 MPa, respectively, which corresponds to the conditions of partially miscible displacement.

At 35 °C and growing pressure, the oil displacement coefficient at first increases from 53 to 60 %, and then at the pressure of 12 MPa goes down to 58 %. It is most likely that at this concentration of carbon dioxide heavy fractions of oil begin to precipitate. The oil displacement pattern at 35 °C and in the pressure range of 7–12 MPa corresponds to the conditions of immiscible displacement. It should be noted that, as the temperature rises, the pressure of the heavy oil fraction precipitation point increases as well (at 23 °C, the oil displacement coefficient began to go down at 8.5 MPa, and at 35 °C, it was 12 MPa), which is caused by the reduction in dissolution of carbon dioxide and higher solubility of heavy fractions in oil.

At 150° and 200 °C and growing pressure, the oil displacement coefficient increases steadily from 45.6 to 49.5 % (150 °C) and from 53.1 to 54.0 (200 °C), which is related to the low miscibility of carbon dioxide in oil and stability of heavy fractions in the solution. At the same time, the oil displacement coefficient at 200 °C is somewhat higher than at 150 °C, which can be explained by the reduction of oil viscosity and the increasing effect of the hydrodynamic displacement of oil. Lower oil displacement coefficients at 150° and 200 °C as compared with those at 23° and 35 °C are due to the increased possibility of CO_2 breaking through the model at high displacement temperatures.

It was discussed earlier that the rise in displacement pressure should entail an increase in the gas-oil displacement coefficient. However, when pressure rises to 10–12 MPa at 23 °C it lowers the oil displacement coefficient, and it happens with the simultaneous decrease in the average volume rate of CO_2 to the point of gas escape from 0.13 to 0.04 cm^3/min (the ingestion of CO_2 was performed at constant differential pressure of 1 MPa in all tests) (Fig. 5).

Table 2

Physicochemical properties of the degassed oil of the Permo-Carboniferous reservoir in the Usinskoye field

Sample	Viscosity of degassed oil, mPa·s		Oil density at 20 °C, kg/m^3	Paraffins, %	Resins, %	Asphaltenes, %
	at 20 °C	at 50 °C				
Primary oil	3799	390	950.3	0.58	30.39	10.15
After injection of 1.2 V_{por} CO_2	125	25.7	935	0.31	20.26	6.16

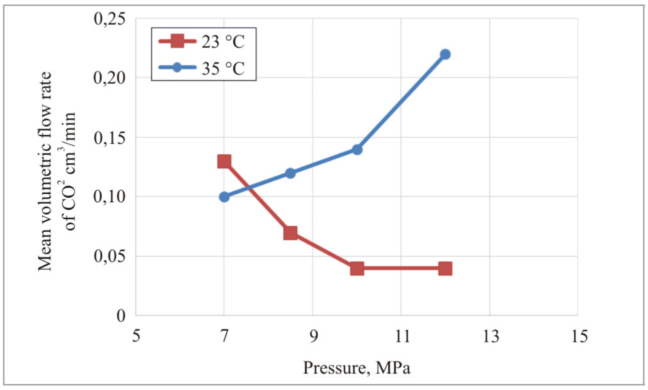

Fig. 5. Change in the average volume rate of CO_2 at increasing displacement pressure in slim-models

It can be traced that as displacement pressure grows, the slim model shows a drop in the volume rate of CO_2 to the point of escape, which indicates growth in hydraulic resistancies in the slim model. At the displacement temperature of 35 °C, on the contrary, the growth in displacement pressure is accompanied by an increase in the average volume rate of CO_2, which is most likely caused by the precipitation of heavy fractions of oil and reservoir clogging, with some of the oil resting immobile in the pores of the slim model.

Unfortunately, the scope of this research did not focus on determining conditions that destabilize asphaltenes in oil. Therefore in order to confirm the assumption about the destabilization of asphaltenes, while the displacement process was in progress, samples of the displaced oil slim model were taken to study its physicochemical properties and compare them with the primary oil. We measured viscosity at 20° and 50 °C and density at 20 °C, and determined the composition of high molecular components. Table 2 shows the physicochemical properties of primary oil as compared with that displaced by carbon dioxide at 35 °C and 8.5 MPa at the final stage of the experiment.

As it is seen from the results of tests on oil samples taken at the exit from the slim tube, after injecting 1.2 V_{por} carbon dioxide, the displaced oil shows a 39 % decrease in asphaltenes, resin decreases by 33 %, paraffins by 47 %, its viscosity is reduced 15–30-fold, and its density decreases insignificantly. During oil displacement, carbon dioxide extracts light hydrocarbons, while heavy hydrocarbons (including asphaltene-resin-paraffin deposits) precipitate in the reservoir, which results in that the displaced oil has a chemical composition and properties different from those characteristic of the primary oil. This fact ascertains the precipitation of heavy fractions of oil (asphaltenes, resins, and paraffins) in the porous medium of the slim model and makes for the decrease in the oil displacement coefficient.

Conclusion

The conducted studies result in the following conclusions.

1. It is a technically challenging task to obtain a uniform mix of carbon dioxide with heavy oils, which is tackled by the authors in a number of ways.
2. The rate at which a mix reaches uniformity depends on the thermodynamic and mechanical conditions of how oil mixes with carbon dioxide, the properties of oil itself, as well as its composition, dissolved gas, and pattern of its interaction with carbon dioxide.
3. Only a small amount of carbon dioxide dissolves in the Permo-Carboniferous reservoir oil (up to 17–18 mol. % at initial reservoir temperature and pressure). However, even in small amounts carbon dioxide significantly lowers oil viscosity.
4. The results of the filter tests using slim models suggest that in real conditions of the Permo-Carboniferous reservoir in the Usinskoye field, the most feasible oil displacement scenario involving carbon dioxide should be that of immiscible displacement.
5. As the pressure in the slim model rises to 10.0–12.0 MPa, it leads to a decrease in the oil displacement coefficient, which is likely related to the precipitation of heavy fractions in the pore volume of the slim model and its clogging. This assumption is confirmed by the determined physicochemical properties of oil displaced by carbon dioxide.

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