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Estimation of the Influence of Associated Petroleum Gas with a High Carbon Dioxide Content on the Oil Displacement Regime in the Development of the Tolumskoye Field**Oleg A. Morozuk¹, Stanislav A. Kalinin¹, Sergey A. Kalinin¹, Andrey S. Scvortsov¹, Sergey V. Melekhin¹, Andrey V. Stenkin², Ruslan R. Mardamshin², Gennady A. Usachev³, Dmitry A. Mett³**¹PermNIPneft branch of LUKOIL-Engineering LLC in Perm (3a Permskaya st., Perm, 614015, Russian Federation)²LUKOIL-Western Siberia LLC, TPE Urayneftegaz (116a Lenina st., Urai, 628285, Russian Federation)³Head office of LUKOIL-Engineering LLC (Bldg. 1, 3 Pokrovsky Boulevard, Moscow, 109028, Russian Federation)**Оценка влияния попутного нефтяного газа с высоким содержанием диоксида углерода на режим вытеснения нефти при разработке Толумского месторождения****О.А. Морозюк¹, С.А. Калинин¹, С.А. Калинин¹, А.С. Скворцов¹, С.В. Мелехин¹, А.В. Стенькин², Р.Р. Мардамшин², Г.А. Усачев³, Д.А. Метт³**¹Филиал ООО «ЛУКОЙЛ-Инжиниринг» «ПермНИПИнефть» в г. Перми (Россия, 614015, г. Пермь, ул. Пермская, 3а)²ООО «ЛУКОЙЛ-Западная Сибирь», ТПП «Урайнефтегаз» (Россия, 628285, Ханты-Мансийский автономный округ, г. Урай, ул. Ленина, 116а)³Головной офис ООО «ЛУКОЙЛ-Инжиниринг» (Россия, 109028, г. Москва, Покровский бульвар, 3 стр. 1)

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Depending on reservoir conditions, composition of reservoir oil and gas agent, various modes of oil displacement by gas can be implemented in reservoir conditions. The most preferable mode from the standpoint of the completeness of oil recovery is the mode of miscible displacement of oil by gas. The main parameter indicating the achievement of the miscible displacement mode is the minimum miscibility pressure. The most popular and reliable laboratory method for determining the minimum mixing pressure is the slim-tube method.

The results are presented related to laboratory studies performed to determine the value of the minimum miscibility pressure of reservoir oil from the Tolumskoye field and associated petroleum gas of the Semivodskaya group of fields and also to determine the mode of oil displacement by associated petroleum gas. To determine the parameters of reservoir oil and change its properties at various molar concentrations, the standard PVT research technique was used. To determine the minimum miscibility pressure, the slim-tube technique was used. To assess the mechanism of miscibility process development, chromatographic analysis of the sampled gas composition and visual analysis of the phase fluids behavior by means of a visual cell were additionally performed.

Two series of filtration experiments were performed on slim models aimed at displacement of the recombined oil model of the Tolumskoye field by the model of associated petroleum gas from the Semivodskaya group of fields. According to the obtained dependence of the oil displacement coefficient on pressure, when oil from the Tolumskoye field was displaced by associated petroleum gas of the Semivodskaya group of fields, the minimum miscibility pressure would be 14.8 MPa.

Based on the criteria for determining the mixing mode, as a result of generalization and comprehensive analysis of the research results, it was found that for the conditions of the Tolumskoye field, the mode of oil displacement by associated petroleum gas of the Semivodskaya group of fields was the mode of the developed multi-contact miscible displacement (the mechanism of condensation of solvent components into the oil phase).

Ключевые слова:

экспериментальные исследования, минимальное давление смешимости, попутный нефтяной газ, газ, нефть, slim-tube, режим вытеснения, смешивающееся вытеснение нефти.

В зависимости от пластовых условий, состава пластовой нефти и газового агента, в пластовых условиях могут реализовываться различные режимы вытеснения нефти газом. Наиболее предпочтительным режимом с позиции полноты извлечения нефти, является режим смешивающегося вытеснения нефти газом. Основным параметром, указывающим на достижение режима смешивающегося вытеснения нефти, является минимальное давление смешимости (МДС). Наиболее востребованным и достоверным лабораторным методом определения МДС является метод slim-tube.

Представлены результаты лабораторных исследований, выполненные с целью определения величины МДС пластовой нефти Толумского месторождения и попутного нефтяного газа (ПНГ) Семиводской группы месторождений и определения режима вытеснения нефти ПНГ. Для определения параметров пластовой нефти и изменения ее свойств при различной мольной концентрации ПНГ использовалась стандартная методика PVT-исследований. Для определения МДС использовалась методика slim-tube. Для оценки механизма развития процесса смешиваемости дополнительно производился хроматографический анализ состава отбираемого газа и визуальный анализ фазового поведения флюидов посредством визуальной ячейки.

Выполнены две серии фильтрационных опытов по вытеснению рекомбинированной модели нефти Толумского месторождения моделью ПНГ Семиводской группы месторождений на slim-моделях. Согласно полученной зависимости коэффициента вытеснения нефти от давления, при вытеснении нефти Толумского месторождения попутным нефтяным газом Семиводской группы месторождений величина МДС составит 14,8 МПа.

Опираясь на критерии определения режима смешения, в результате обобщения и комплексного анализа результатов исследований установлено, что для условий Толумского месторождения, режимом вытеснения нефти попутным нефтяным газом Семиводской группы месторождений является режим развиваемого многоконтантного смешивающегося вытеснения (механизм конденсации компонентов растворителя в нефтяную фазу).

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Просьба ссылаться на эту статью в русскоязычных источниках следующим образом:

Оценка влияния попутного нефтяного газа с высоким содержанием диоксида углерода на режим вытеснения нефти при разработке Толумского месторождения / О.А. Морозюк, С.А. Калинин, С.А. Калинин, А.С. Скворцов, С.В. Мелехин, А.В. Стенькин, Р.Р. Мардамшин, Г.А. Усачев, Д.А. Метт // Недропользование. – 2021. – Т.21, №1. – С.42–48. DOI: 10.15593/2712-8008/2021.1.7

Introduction

The process of gas stimulation of the oil reservoir involves the injection of a gas agent into the formation in order to achieve miscibility [1]. The classic technology is performed by injecting a large volume of gas into the formation for oil displacement. However, an adverse ratio of viscosities of the displaced oil and injected gas causes formation of gas fingers that break through into the production wells and lead to a dramatic increase in the gas-oil ratio and a decrease in oil production rates. In order to eliminate the issue of fingering, gas injection technology is combined with water injection in various forms. This technology can be implemented in the following forms: carbonated water injection [2–4], gas-oil displacement with subsequent water-oil displacement [5], alternate injection of water and gas rims (WAG) [6, 7].

Recently, many oil-well experts have been researching a technology that is more likely a type of a group of water-gas stimulation technologies [8] which consists of injecting a highly dispersed water and gas mixture (water-gas mixture (WGM)) at a specific volumetric phase ratio. This high-potential technology can substantially increase the efficiency of oil displacement; its implementation, however, is facing a number of technical and technological challenges [8–10].

One of the types of technologies that use gases is the gas cycling technology (Huff'n'Puff) [11] which is implemented through the injection of a gas agent into the formation in cycles. Each cycle has three successive steps: 1) gas injection, 2) soaking, 3) well sampling.

Gases such as nitrogen [12, 13], carbon dioxide [14, 15], flue gases [16, 17], hydrocarbon "dry" gases (methane) and "upgraded" gases (e.g. associated petroleum gas) can be used as gas agents [18].

Depending on the reservoir conditions, reservoir oil composition and gas agent, various scenarios of oil displacement by gas can be implemented in reservoir conditions [19, 20]. There are three main gas-oil displacement scenarios [21]: 1) immiscible displacement, 2) partially-miscible displacement (or displacement with developed miscibility or multiple-contact miscibility), 3) fully miscible displacement (or miscible displacement at the first contact). The most preferable scenario in terms of the completeness of oil recovery is the completely miscible displacement of oil by gas which is implemented at pressures above the so-called minimum miscibility pressure (MMP).

It is important to determine the displacement scenario and MMP when estimating the efficiency of oil displacement by gas agents (as well as other technologies that use gas as a displacement agent). Due to the fact that the results of these studies depend on the temperature and pressure conditions of the given formation, oil composition and the applied gas agent, an important step of laboratory studies is to prepare fluid samples. This step also includes the preparation of a recombined oil sample with a gas agent model followed by conducting a set of PVT studies according to the data [22].

The mechanism of oil displacement by means of a gas agent and the MMP can be determined by both calculation (using state equations) [23–25] and a number of experimental methods [26–29]. However, the most consistent results can be provided by experimental methods only.

This paper presents the results of laboratory studies performed to determine the value of the minimum miscibility pressure (MMP) of reservoir oil from the Tolumskoye field and associated petroleum gas (APG) of the Semivodovskaya group of fields and also to determine the scenario of oil displacement by associated petroleum gas. The standard PVT research technique was used to determine the parameters of reservoir oil and changes in its properties

at various molar concentrations of APG. The slim-tube technique was used to determine the MMP. In order to assess the mechanism of the miscibility process development, chromatographic analysis of the sampled gas composition and visual analysis of the phase fluids behavior by means of a visual cell were additionally performed.

Research Procedure

The most popular and reliable laboratory method for determining the minimum miscibility pressure is the slim-tube method [30].

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 miscible 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.

The slim-tube method of the MMP measurement consists of a set of experiments carried out to displace oil with a solvent agent using long tubes of small diameter. The tube diameter is usually 4–15 mm [31–33]. The tube length varies from 6 to 40 m. The tube is usually filled with porous media with small particle sizes to meet the condition $D_{\text{tube}}/D_{\text{particles}} > 10$ [34].

There is no clear and precise procedure for measuring MMP by the slim-tube method at the moment, therefore there are many various criteria for analyzing the miscibility of reservoir oil and gas designed before the 1990s:

- oil displacement factor of 90 % and above at 1–1.2 V_{pore} injected into the slim model [35–37];
- oil displacement factor of 95 % and above after the gas breakthrough for some types of injection agents [38] and 80 % after the gas breakthrough and the final oil displacement factor of 94 % for most of the displacement agents [39, 40];
- oil displacement factor of 94 % and above when gas factor reaches the set value [39, 40];
- The MMP is determined in a set of experiments at different displacement pressures at 1.2 V_{pore} injected into the slim model. The MMP corresponds to the breakpoint of the displacement factor – displacement pressure curve [30, 41, 42], as well as a number of others [42–44].

It is often assumed that full miscibility is achieved when at least 90 % of oil is displaced after injection of a gas agent in a volume equal to 1.2 pore volumes of the slim model. If the experiment results show that the final displacement factor is less than 50–60 %, the displacement process is considered to be immiscible. Obtaining an intermediate value of the displacement factor (60–90 %) corresponds to the conditions of partial miscibility. At least five experiments with different displacement pressures are carried out, after which a graph of the dependence of the oil displacement factor on the displacement pressure is constructed. The intersection point of the line dropped vertically from the breakpoint of the experiment curve onto the pressure axis corresponds to the MMP value (Fig. 1).

Fig. 1. Displacement factor vs pressure curve (example)

Fig. 2. Three-phase filtration apparatus and slim model in the oven

Fig. 3. Cell with a sight glass for checking up on phase behavior of fluids

Fig. 4. Volume factor of the recombined oil model of the Tolumskoye field vs. pressure

Table 1

Specifications of the appliance for determining minimum miscibility pressure

Parameter	Value
Tube length, m	12
Tube outside diameter, mm	6
Packing	Stainless steel
Packing material	Glass microspheres
Grain size, mesh	100
Porosity, %	38.4
Gas permeability, μm^2	33
Pore volume, cm^3	130.4
Maximum operating pressure, MPa	40.0
Maximum operating temperature, $^{\circ}\text{C}$	200

The processing of the results of filtration experiments using slim models and the evaluation of the miscibility mechanism were carried out according to the criteria given in [45]. The authors suggested to use the following experimental data:

- dynamics of methane concentration in gas escaping from displaced oil,
- phase behavior of fluids as they leave the slim model,
- dynamics of the pressure difference between the ends of the slim model,
- displacement factor value.

Equipment Description

The researchers used modern laboratory equipment that provided the possibility to perform filtration experiments using core and bulk formation models with the application of different displacement agents in a wide range of temperatures and pressures (Fig. 2). The appliance consisted of several units for various functions. See [46] for the detailed description.

The associated petroleum gas model (APG) was injected by using the gas preparation unit designed to compress and heat gas up to the required pressure and temperature and supply the prepared gas to the injection pump. The phase measurement at the slim model outlet was performed by using an apparatus for measuring the volume of fluids that consists of a three-phase visual separator and special piston-type flow meters positioned after the separator. The phase behavior of the fluids sampled during the experiment was checked by using a high-pressure cell with a sight glass installed in front of the back pressure valve (Fig. 3). Table 1 shows technical specifications for the used slim model.

Preparing Formation Fluid Models

A recombined reservoir oil sample of the Tolumskoye field and an APG model of the Semivodovskaya group of fields were prepared for the filtration experiments using slim-models.

The recombined oil sample was prepared in a special recombination chamber. The sample is mixed in the mixing cell at the pressure of up to 25 MPa and at the temperature of up to 150 $^{\circ}\text{C}$. The fluid is mixed by a ball moving inside the cell.

The recombined sample was prepared using a wellhead oil sample from the production wells of the Tolumskoye field. The following physicochemical properties of the wellhead sample were determined before the experiment: irreducible water saturation, viscosity and density at 20 $^{\circ}\text{C}$, weight content of asphaltens, resins and paraffins, molecular weight and components.

The recombined oil model was prepared in the following order:

- dehumidification of the original degassed oil sample;
- adding an estimated amount of degassed oil and reservoir gas into the recombination cell in a volume corresponding to the gas/oil ratio in the reservoir conditions. Defining the ratio of the gas model components based on the composition of the reservoir gas from the Eastern reservoir of the Tolumskoye field;
- increasing the pressure and temperature in the recombination vessel up to the initial in situ conditions of the Eastern reservoir of the Tolumskoye field;
- mixing oil and gas until reaching a single-phase state;
- measuring the current gas/oil ratio by the flash separation method while mixing the recombined sample;

The PVT properties of the recombined oil sample were defined according to OST 153-39.2-048-2003 Oil. Model study of reservoir fluids and separated oils.

At the stage of the PVT studies of the recombined oil model, correlations between the volume factor and pressure were determined (Fig. 4). These correlations were used later for calculations of oil displacement factors.

The APG model was prepared using the statistical partial pressure method. The compositional analysis of the gas mixture was carried out by using a gas sample taken from the vessel for gas chromatographic analysis. Table 2 shows the comparison between the composition of the APG model used for the experiments and that of the real APG of the Semivodovskaya group of fields.

Table 2
Composition of APG of the Semivodovskaya group of fields and of its model

Component	Designation	APG of the Semivodovskaya group of fields, mol. %	APG model, mol. %
Carbon dioxide	CO ₂	68–72	69.0
Nitrogen	N ₂	0.5–1.5	1.2
Methane	CH ₄	18–20	19.3
Ethane	C ₂ H ₆	0.5–1.5	1.2
Propane	C ₃ H ₈	4–7	6.5
Butane (group)	C ₄ H ₁₀	0.1–0.5	0.4

Fig. 5. Standard experiment results: *a* – dynamics of pore and differential pressures during the experiment on determination of the oil displacement factor using slim tubes; *b* – dynamics of oil displacement depending on the volume of the injected APG in slim tube pore volumes; *c* – dynamics of the gas factor depending on the volume of the injected APG in slim tube pore volumes

Experiment Procedures

The slim model preparation included the following steps:

- the slim model was put under vacuum for 2 hours;
- saturation of the slim model with minimum $3 V_{\text{pore}}$ of kerosene by means of kerosene filtration;
- injecting the recombined oil sample through the slim model at the formation temperature of 91 °C and at a pressure higher than the saturation pressure.

The oil displacement stage was performed as described below:

- setting the required pore pressure stage in the slim tube;

b) holding the slim model at the formation temperature and set pore pressure for 24 hours;

c) injecting APG into the slim model with a constant volume flow rate of 0.08 cm³/min providing a low pressure gradient along the length of the slim model;

d) measuring volumes of fluids as they leave the slim model by means of piston-type flow meters as often as it may be necessary to determine the composition (oil up to C₃₀ +, gas up to C₆ +) and physicochemical properties;

e) analyzing changes in composition of gas escaping from oil by taking gas samples after every 0.1 pore volumes of APG injected and analyzing it with a gas chromatograph;

f) analyzing changes in composition of oil based on the components, density, viscosity and content of asphaltenes, resins and paraffins of degassed oil samples taken during the experiment;

g) checking up on the phase behavior (in reservoir conditions) of fluids leaving the slim model by means of a special visual cell;

h) injecting APG in a volume equal to 1.2-times the volume of the slim model void space, after which the experiment was stopped;

i) the oil displacement factor (K_{disp}) was calculated based on the total volume of oil samples taken for analysis by the following equation:

$$K_{\text{BT}} = \frac{V_{\text{BH}} \cdot b - V_{\text{mept}}}{V_{\text{nop}}},$$

where $V_{\text{disp, oil}}$ is the displaced oil volume, cm³; b is the oil volume factor corresponding to the pore pressure stage and formation temperature, units; V_{void} is the void volume of the hydraulic system, cm³; V_{pore} is the pore volume of the slim model which equals to the volume of oil originally present in the slim model, cm³.

The slim model was cleaned as described below:

a) heating the oven with the slim model up to the temperature of 150 °C;

b) injecting white spirit through the tube until it comes out of the tube completely discolored;

c) cooling the oven with the slim model down to room temperature;

d) injecting 2 times the pore volume of kerosene through the slim model at a pressure equal to the next stage pore pressure;

e) re-saturating the slim model with the recombined oil sample.

Results of Filtration Experiments using Slim Tubes

Within the research, two sets of experiments were performed to displace the oil model of the Tolumskoye field by the APG model from the Semivodovskaya group of fields. The second set of experiments was carried out in order to repeat the first set and thus improve the reliability of the research results. Figure 6 shows typical outcomes of the experiments. Table 3 summarizes the outcomes of the experiments.

Figure 5 shows correlations between oil displacement factor and pore pressure value obtained using slim tubes.

As one can see from the data shown in Figure 6, an increase in the displacement pressure entails growth of the displacement factor. At pressure stages from 15 to 17.2 MPa, the oil displacement factor is nearly stabilized. An experiment performed at 20 MPa showed that the displacement factor keeps increasing along with the increase in the displacement pressure.

Table 3

Results of the experiment on the MMP measurement

Experiment No.	$T_{\text{formation}}, ^\circ\text{C}$	Stage $P_{\text{formation}}, \text{MPa}$	APG volume flow rate (CO_2), cm^3/min	Differential pressure in the tube, MPa		Oil displacement factor after injection of 1.2 V_{pore} of APG, %
				max	after gas breakthrough	
Set 1						
1	91	10	0.080	0.144	0.017	0.379
2	91	12	0.080	0.134	0.018	0.530
3	91	15	0.080	0.121	0.016	0.715
4	91	16	0.080	0.117	0.011	0.699
5	91	17.2	0.080	0.111	0.012	0.707
Set 2						
1	91	12	0.080	0.132	0.015	0.536
2	91	15	0.080	0.132	0.014	0.666
3	91	16	0.080	0.116	0.012	0.675
4	91	17.2	0.080	0.109	0.013	0.666
5	91	20	0.080	0.114	0.013	0.758

Table 4

Evaluation of the displacement mechanism

Criterion	First contact miscible displacement	Displacement mechanism		Immiscible displacement
		Multiple-contact miscibility	Evaporation	
Rapid change in methane concentration	No	Yes	No	Significant arch of methane concentration
Two phases in the visual cell	No	Yes	No	Yes/large number of bubbles in the flow
Low pressure difference after injection of 1.2 V_{pore} of solvent	Yes	Yes	Yes	No
Displacement factor value after injection of 1.2 V_{pore} of solvent, %	≥ 90	$\geq 90^*$	≥ 90	< 90

Note: * – low displacement factor values are caused by insufficient development of the transition section in the slim tube. The criteria that correspond to the results obtained during researches are shown in green.

Fig. 6. Correlation between oil displacement factor and pore pressure value based on the results of filtration experiments

The points before the break obtained at 10, 12 and 15 MPa, as well as the points after the break at 16, 17.2 and 20 MPa were approximated by linear dependencies. The normal dropped vertically from the intersection point of the straight lines onto the pressure axis corresponds to the MMP value which amounts to 14.8 MPa.

The obtained displacement factor values show the absence of miscible displacement at the first contact (the oil displacement factor is significantly less than 100 %). Yet they cannot indicate an immiscible displacement process since such displacement factor values may be caused by the sizes of the transition section that might be not fully developed in the simulation conditions, which did not allow for a more complete displacement of oil from the slim tube. Therefore, the displacement mechanism was evaluated based on the set of criteria described earlier.

Analysis of the fluids composition. According to the procedure described above, the dynamics of methane concentration in the sampled gas was separately analyzed for the further analysis of the results in order to determine the displacement scenario. Changes in composition of gas escaping from oil were analyzed during filtration experiments by taking gas samples after every 0.1 pore volumes of the injected APG model with their immediate loading into the gas chromatograph. Figure 7 shows the

results of the chromatographic analysis of gas samples taken at 16 and 17.2 MPa.

At the first stage of the experiment, methane concentration corresponds to that in gas dissolved in oil, since only oil is displaced. Then, before APG breaks through, a rapid change in methane concentration occurs which is characterized by the "peak" value and "arch" dimensions. After the peak, a rapid decrease in methane concentration occurs, which is the consequence of the APG model breakthrough. Ultimately, the methane concentration reaches the level that corresponds to the APG model composition. The research [15] states that such a peak indicates the development of the multiple-contact miscible displacement process. The authors also note that a rapid change in methane concentration and formation of an arch reliably indicate that the oil composition is not changing.

The results of the chromatographic analysis of samples confirm the fact that the properties of oil of the Tolumskoye field do not change during the APG displacement. Figure 7 shows the results of the chromatographic analysis of oil samples taken at 16 MPa during the experiment (oil composition is shown without heavy residue C35+).

Observation of the phase behavior. The phase behavior is one of the criteria in evaluating the oil displacement mechanism. The video records of the phase behavior of fluids displaced from the slim tube were also used to interpret the results. The following phase behavior types can be observed when fluids move in the course of the experiments:

a) one phase is present – first contact miscible displacement or developed multiple-contact miscible displacement with the evaporation of components into a gas phase;

b) the presence of small gas bubbles that start moving along with oil right before the displacement agent breaks through indicates the developed multiple-contact miscible displacement scenario with the condensation of gas into an oil phase. In this case, methane concentration is characterized by a concentration arch that is present before the gas agent breaks through;

Fig. 7. Dynamics of methane concentration in the sampled gas during experiments at pressures of 16 MPa (set 1) and 17.2 MPa (set 2)

Fig. 8. Compositional analysis of degassed oil samples taken during the experiment performed at 16 MPa using a slim tube

Fig. 9. Results of the visual observation of the phase behavior of fluids as they leave the slim tube: a – the first experiment stage (set 1, experiment No. 3, 15 MPa, injection: 0 V_{pore}); b – the APG model starts breaking through (set 1, experiment No. 3, 15 MPa, injection: 0.655 V_{pore}); c – the last experiment stage (set 1, experiment No. 3, 15 MPa, injection: 1–1.2 V_{pore})

c) a large number of bubbles emerging during the displacement process indicate that the displacement is immiscible.

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Figure 9 shows typical displacement stages seen in the visual cell by using an experiment performed at 15 MPa as an example.

Gas bubbles start moving before APG breaks through. After the breakthrough, one can see a clear separation of two phases in the visual cell. After that, oil moves in the lower part of the sight glass, while gas moves in its upper part.

Table 4 presents a detailed summary of the experimental results.

Conclusions

The following conclusions can be drawn based on the research results.

According to the obtained dependence of the oil displacement coefficient on pressure, when oil from the Tolumskoye field is displaced by associated petroleum gas of the Semivodovskaya group of fields, the minimum miscibility pressure would be 14.8 MPa.

The profiles of methane concentration in gas released from the oil displaced during the experiments are characterized by a rapid change in methane concentration. This rapid change in concentration shows that a multiple-contact miscible displacement process is being developed in the formation, and that oil composition does not change when displacement of oil by APG is ongoing.

The analysis of physicochemical properties and chromatographic analysis of degassed oil samples confirm that oil composition remains the same during displacement of oil by APG.

The pressure difference observed during the experiment significantly decreases by the time the APG model is injected in a volume equal to 1.2 V_{pore} of the slim tube, which indicates the formation of the multiple-contact or first contact miscible displacement process.

Visual observation established that right before the APG model breaks through the slim tube, gas bubbles start moving. After the breakthrough, the formation of two phases occurs as observed in the visual cell. This situation is typical for all the performed experiments.

The oil displacement factor values obtained at pressures higher than MMP are below 90 %. Low displacement factor values are caused by insufficient development of the transition section for which there might not be enough time to develop on a slim 12 m long tube in the given simulation conditions (composition of the recombined oil sample and APG model, temperature and pressure conditions), which is confirmed by the same displacement factors obtained during repeated experiments.

Based on the criteria for determining the mixing mode, as a result of generalization and comprehensive analysis of the research results, it was found that for the conditions of the Tolumskoye field, the type of oil displacement by associated petroleum gas of the Semivodovskaya group of fields was the developed multiple-contact miscible displacement (the mechanism of condensation of solvent components into oil phase).

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