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Laboratory Experiments of Hydrocarbon Gas Flooding and Its Influencing Factors on Oil Recovery in a Low Permeability Reservoir with Medium Viscous Oil

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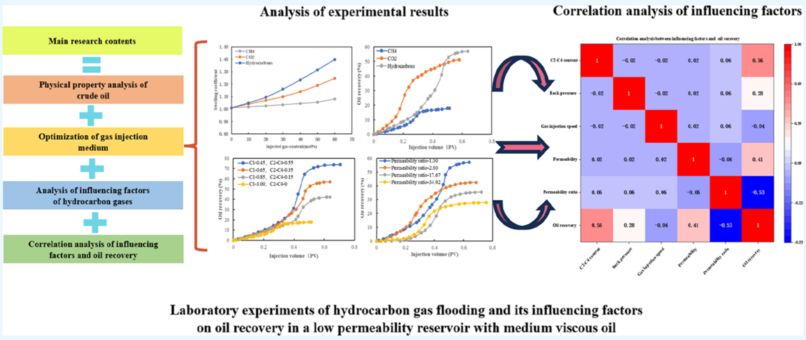

ABSTRACT: In view of the problems of low liquid production, a high proportion of high water cut wells, and poor development effect in the late stage of water flooding in the special sandstone reservoir of Niuquanhu "low permeability and medium viscosity crude oil", we carried out the research on hydrocarbon gas oil recovery and its influencing factors. First, the influence of different injected gas media on the physical properties of crude oil was analyzed. Second, the core displacement experiments of different gas injection media including CO_2, CH_4, and hydrocarbon gas were carried out by using the method of oil recovery comparison and optimization. Third, the indoor experimental study on the oil recovery of different influencing factors was carried out by using the method of controlling variables of influencing factors. Finally, the influence degree of different influencing factors on oil recovery was analyzed by a Spearman rank correlation coefficient analysis. The experimental results showed that the oil recovery of hydrocarbon gas is higher than that of CO_2 and CH_4, which were 57, 51, and 18% respectively. This is mainly because hydrocarbon gas is similar to the components of crude oil and is more easily dissolved in crude oil. The experimental results of influencing factors showed that the higher the content of C_2-C_4, the higher the oil recovery, and the content of C_2-C_4 will affect its dissolution with crude oil and its interaction with heavy component crude oil. The larger the permeability ratio, the lower the oil recovery, which was mainly due to the uneven distribution of injected gas in different regions. The higher the permeability, the lower the oil recovery, which was also due to the serious heterogeneity of the low permeability core of Niuquanhu; The results of Spearman rank correlation coefficient analysis based on different influencing factors and oil recovery showed that the order of influence of different factors on oil recovery was C_2-C_4 content > permeability ratio > permeability > back pressure > gas injection rate. In the development process of hydrocarbon gas injection, we should control the C_2-C_4 content, back pressure, and injection rate. The research in this study not only provides theoretical support for gas injection enhanced oil recovery technology in "low permeability and medium viscosity crude oil" reservoirs but also provides a new idea for the ranking of influencing factors.

1. INTRODUCTION

Niuquanhu Oilfield is located in the northern part of Malang Sag, Santanghu Basin, Turpan-Hami Basin, and eastern Xinjiang. It belongs to the reservoir of the continental clastic sedimentary reservoir type. The structure is a wide and gentle anticline distributed in the near east−west direction. The north and south wings are clamped by reverse faults, and the core is dominated by fine-medium-grained feldspar lithic sandstone.[1] The average porosity of the reservoir is 12.5%, the average permeability is 2.74×10^{-3} μm^2, the average oil saturation is 54%, and the average crude oil density is 0.870 g/cm^3.

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Conventional low permeability reservoirs belong to light oil reservoirs, and the viscosity of crude oil is generally 1−2 mPa s, but the viscosity of crude oil in the Niuquanhu reservoir reaches 20 mPa·s, which is a typical low permeability and medium viscosity crude oil special type sandstone reservoir.[2,3] Due to the characteristics of "low permeability and medium viscous crude oil" of Niuquanhu reservoir, it lead to unsatisfactory development effect of water injection, low production of oil wells, and low oil recovery. In short, for this special reservoir of "low permeability and medium viscosity crude oil ″, it is urgent to change or explore new development methods to improve oil recovery. Compared with injected water, the gas medium has better injection ability and stronger diffusion ability. Therefore, gas flooding is widely used in unconventional reservoirs such as low permeability, ultralow permeability, and tight reservoirs to improve oil recovery. Common gas injection media include CO_2, N_2, and hydrocarbon gas.[4] Among them, CO_2 flooding is suitable for low permeability reservoirs, ultralow permeability reservoirs, deep water reservoirs, and high sulfur reservoirs.[5] When CO_2 contacts with crude oil, it will interact with the light components in crude oil physically and chemically, resulting in the dissolution of light components in crude oil and CO_2 and diffusion into crude oil.[6] This will change the physical properties of crude oil, such as reducing the viscosity and surface tension of crude oil, increasing the fluidity of crude oil, and thereby promoting the flow and recovery of crude oil.[7] After CO_2 is injected into the reservoir, it will diffuse into the pores and expand with a decrease in pressure. This expansion can increase the relative permeability between crude oil and CO_2 and improve the displacement effect of CO_2.[8] The expansion of CO_2 can also change the fluid distribution in the pores and improve oil recovery. At present, the United States is one of the most widely used countries in the world for CO_2 flooding. CO_2 flooding technology has been successfully applied in many oil fields in the United States, especially in low-permeability and ultralow permeability reservoirs in Texas, Colorado, and New Mexico.[9] Canada is another country where the application of CO_2 flooding is relatively mature. In Alberta, Canada, CO_2 flooding technology has been widely used in the heavy oil belt of the Shatel River.[10] In China, the Changqing Oilfield is one of the important oil fields that apply CO_2 flooding technology in China. Changqing Oilfield has carried out CO_2 flooding tests and applications in low-permeability and ultralow permeability reservoirs and achieved good results.[11] Especially in the Chang 8 reservoir of the Changqing Oilfield, CO_2 flooding technology is widely used to improve oil recovery. CH_4 flooding is suitable for low-permeability reservoirs, low-pressure reservoirs, and high-viscosity crude oil reservoirs.[12] CH_4 can be partially dissolved in crude oil to form an oil- and gas-phase dissolution system. Since the density of CH_4 is smaller than that of crude oil, the dissolved gas phase will reduce the effective density of crude oil and reduce the viscosity of crude oil, thereby improving the fluidity of crude oil.[13] Dissolved CH_4 can also increase the gas phase relative permeability of crude oil and improve the seepage capacity of crude oil. After CH_4 is injected into the reservoir, crude oil can be driven out by seepage due to its relatively low viscosity and high permeability. CH_4 gas has a high permeability and a large effective pressure gradient, which can effectively promote the flow of crude oil and increase the oil recovery. The phenomenon of CH_4 retention in the reservoir is also an important mechanism of oil displacement. The small size of the methane molecule enables it to penetrate the small pores of the reservoir to form a gas retention phase. These retained CH_4 molecules can change the saturation of the oil phase and reduce the viscosity of the oil phase, thereby improving the fluidity of the crude oil.[14] At present, the research on the use of CH_4 to displace crude oil at domestic and abroad is still in its infancy, and there are almost no cases of CH_4 used in oil fields for oil displacement.[15] With the continuous development of technology and the increasing demand for enhanced oil recovery and improved crude oil mobility in China, CH_4 flooding technology is expected to receive more attention and application in China.

Hydrocarbon gas flooding is suitable for low-permeability reservoirs, high-viscosity crude oil reservoirs, and heavy crude oil reservoirs. Zhu[16] et al. found that hydrocarbon gas components are similar to crude oil components, which can be dissolved in crude oil to form gas dissolution and desorption equilibrium. According to the principle of similar miscibility, when hydrocarbon gas is dissolved in crude oil, the viscosity and surface tension of crude oil will be reduced, making crude oil easier to flow. This dissolution can reduce the relative permeability of crude oil, thereby improving the relative permeability difference between the oil and water phases and enhancing oil recovery. Li[17] et al. found that when hydrocarbon gas is injected into the reservoir, the pressure of the gas will increase, and the increased pressure will push the crude oil to the wellhead. Under high pressure, the volume of the crude oil decreases, thereby increasing the movement power of the crude oil. The experimental results show that the influencing factors of hydrocarbon gas flooding are C_2-C_4 content, back pressure, gas injection rate, permeability, and permeability ratio. At present, hydrocarbon gas flooding is widely used in oil field development in the United States, especially in shale oil and shale gas exploitation. Hydrocarbon gas flooding technology is used to improve oil recovery and increase production.[18] Daqing Oilfield is one of the largest conventional oilfields in China, and the application of hydrocarbon gas flooding has been studied in some test blocks of the oilfield.[19] When hydrocarbon gas is injected into the reservoir, crude oil recovery can be greatly improved. In a word, there are still few studies on the use of hydrocarbon gas flooding in reservoirs with special geological characteristics of "low permeability and medium viscosity crude oil" similar to Niuquanhu, and the biggest advantage of hydrocarbon gas flooding is that it can greatly improve the recovery rate of "low permeability and medium viscosity crude oil" type reservoirs. Therefore, it is necessary to carry out relevant research on hydrocarbon gas flooding.

In order to improve the development effect of the "low permeability and medium viscosity crude oil" reservoir and clarify the main influencing factors of hydrocarbon gas flooding to improve oil recovery technology, this paper first established a core fluid model of "low permeability and low mobility" in the laboratory. The influence of different injection gas media on the physical properties of crude oil was studied by us. On this basis, the indoor core displacement experiment was used to compare the three gas injection methods of CO_2 flooding, CH_4 flooding, and hydrocarbon gas flooding, and the best gas injection medium suitable for gas injection flooding in Niuquanhu reservoir was determined. Considering factors such as C_2-C_4 content, back pressure, gas injection rate, permeability, and permeability ratio, hydrocarbon gas flooding experiments were carried out in turn to clarify the influence of different factors on oil recovery. Finally, we use the Spearman rank correlation coefficient method to systematically analyze the above influencing factors, and give the comparison results of the influence degree of the influencing factors of hydrocarbon gas flooding. The research results of this paper not only verify the feasibility of hydrocarbon gas flooding in "low permeability and medium viscosity crude oil" reservoirs but also put forward new technical ideas for enhancing oil recovery in "low permeability and medium viscosity crude oil" reservoirs.

2. EXPERIMENTS

2.1. Experimental Instruments and Materials. (1) Experimental water: The total salinity of the formation water of Niuquanhu is 5266 mg/L. The formation water used in the experiment is prepared based on the formation water analysis data of the Niuquanhu block. The salinity and ion content are shown in Table 1.

Table 1. Simulating the Salinity and Ion Content of Formation Water

	ion content (mg/L)					
total salinity (mg/L)	Na^+	Ca^{2+}	Mg^{2+}	Cl^-	SO_4^{2-}	HCO_3^-
5266	1670	118	37	2030	257	1154

(2) Experimental oil: The crude oil used in the experiment is taken from the target oil field of Niuquanhu block. The viscosity is 20 mPa s (45 °C), and the density is 0.87 g/cm^3, which belongs to the medium viscosity crude oil. The composition of C_1-C_{40} components is shown in Table 2.

Table 2. Proportion of C_1-C_{40} Components in Niuquanhu

proportion of C_1-C_{40} components (%)					
C_1-C_3	C_4-C_{10}	$C_{11}-C_{13}$	$C_{14}-C_{18}$	$C_{19}-C_{25}$	$C_{26}-C_{40}$
5	27	13	12	10	20

(3) Experimental gas: CH_4 gas (purity 99.99%), CO_2 gas (purity 99.99%), hydrocarbon gas 1 (CH_4 content 85%, C_2-C_4 content 15%), hydrocarbon gas 2 (CH_4 content 65%, C_2-C_4 content 35%), andhydrocarbon gas 3 (CH_4 content 45%, C_2-C_4 content 55%).

(4) Experimental cores: Three short cores with similar permeability of 10 cm are spliced into a long core with a total length of 30 cm, a diameter of 2.5 cm, an average permeability of 2.6 mD, and an average porosity of 13.42%. The experimental cores were man-made cores made according to the porosity and permeability characteristics of the target block. The physical properties of the man-made cores used in our experiment are similar. The average pore size of man-made cores is 2.49 cm. The radius of each core is provided in Table 3. These man-made cores show moderate wettability, and the wetting contact angle range is 60°−70°. The experimental cores data used in the experimental groups with different influencing factors are shown in Table 3, and the experimental cores are shown in Figure 1.

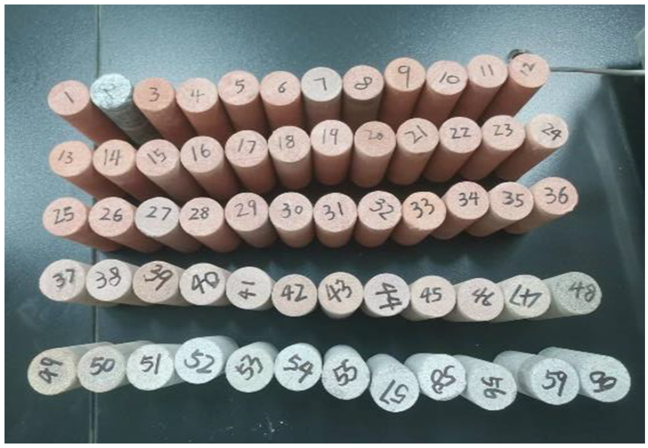

Figure 1. Experimental man-made cores.

Table 3. Experimental Core Data

core number	core length (cm)	core radius (cm)	apparent volume (mL)	pore volume (mL)	saturated oil volume (mL)	porosity (%)	permeability (mD)	saturation (%)
1	30.00	1.25	147.19	18.97	9.43	12.89	3.25	49.73
2	29.57	1.25	145.08	19.61	10.11	13.52	4.87	51.53
3	30.15	1.24	145.57	18.82	9.38	12.93	3.54	49.85
4	30.25	1.24	146.06	19.19	9.68	13.14	3.90	50.44
5	30.35	1.24	146.55	19.71	10.12	13.45	4.76	51.32
6	30.46	1.24	147.04	18.00	8.61	12.24	2.46	47.85
7	30.47	1.23	144.73	18.71	9.33	12.93	3.54	49.85
8	29.60	1.25	145.23	18.71	9.30	12.88	3.32	49.69
9	29.70	1.25	145.72	18.07	8.73	12.40	2.42	48.30
10	30.28	1.24	146.21	18.55	9.11	12.69	2.93	49.13
11	30.38	1.24	146.70	18.98	9.46	12.94	3.54	49.85
12	30.03	1.24	144.98	19.67	10.16	13.57	5.34	51.65
13	29.65	1.25	145.47	14.40	5.92	9.90	0.51	41.14
14	29.75	1.25	145.96	18.89	9.42	12.94	3.54	49.85
15	29.85	1.25	146.45	21.57	11.86	14.73	10.40	54.98
16	30.43	1.24	146.94	24.86	15.23	16.92	44.37	61.26
17	30.07	1.24	145.18	18.79	9.37	12.94	3.54	49.85
18	29.69	1.25	145.67	20.77	11.14	14.26	8.12	53.64
19	30.27	1.24	146.16	22.48	12.78	15.38	29.83	56.86
20	29.89	1.25	146.65	23.02	13.30	15.70	56.09	57.77

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In order to verify the stability of the internal structure of the man-made cores, the porosity and permeability of 20 groups of man-made core samples were tested before and after the experiment. After the core flooding experiment, the oil stains on the surface of the human-made core samples were washeduntil the core surfaces were clean and smooth. Then, the man-made core samples were dried. Finally, the porosity and permeability of these man-made cores were tested. The results of porosity and permeability changes of man-made cores before and after the experiment are shown in Table 4.

Table 4. Changes of Porosity and Permeability before and after the Experiment

cores number	porosity before the experiment (%)	porosity after the experiment (%)	permeability before the experiment (mD)	permeability after the experiment (mD)
1	12.89	12.85	3.25	3.20
2	13.52	13.48	4.87	4.72
3	12.93	12.87	3.54	3.40
4	13.14	13.08	3.90	3.70
5	13.45	13.40	4.76	4.63
6	12.24	12.18	2.46	2.26
7	12.93	12.86	3.54	3.49
8	12.88	12.79	3.32	3.22
9	12.40	12.36	2.42	2.31
10	12.69	12.61	2.93	2.81
11	12.94	12.90	3.54	3.42
12	13.57	13.52	5.34	5.19
13	9.90	9.80	0.51	0.45
14	12.94	12.84	3.54	3.45
15	14.73	14.65	10.40	10.25
16	16.92	16.87	44.37	44.26
17	12.94	12.86	3.54	3.41
18	14.26	14.25	8.12	8.01
19	15.38	15.33	29.83	29.71
20	15.70	15.65	56.09	55.95

The results of data changes in Table 4 show that the overall reduction range of porosity is 0.01−0.1, and the overall reduction range of permeability is 0.05−0.20. In summary, the porosity and permeability of the man-made cores decrease before and after the experiment, but the reduction values are almost negligible. Therefore, it can be concluded that the internal structure of the man-made cores remains stable after the core flooding experiment.

(5) Experimental devices: HC-PVT experimental device is used to test the physical properties of crude oil. The experimental device is shown in Figure 2. The device is mainly composed of a PVT kettle, constant temperature air bath, pressure sensor, temperature sensor, sample tube, high-pressure metering pump, operation control system, and observation and recording system. The high-pressure PVT kettle is a plunger-type variable volume kettle. Its volume change can be controlled by a computer-controlled precision motor to drive the plunger.

The high-temperature and high-pressure core displacement experimental device is used to carry out relevant experiments. The experimental device is shown in Figure 3. The instrument includes an injection system, displacement system, back pressure control system, data acquisition system, pressure monitoring system, and constant temperature system. The injection system contains three piston containers of oil, gas, and water. The piston container for storing gas phase can store CO_2, CH_4, and different proportions of hydrocarbon gases as needed. The displacement system is mainly a core holder, which has a temperature resistance of 150 °C, a pressure resistance of 60 MPa, a diameter of 2.5 cm, and a length of 30 cm. The back pressure control system is a back pressure valve, and the experimental pressure can be set as the formation pressure. The constant temperature system is a constant temperature box, which can be used to control the experimental temperature as the formation temperature. The data acquisition system is mainly used to detect the oil, gas, and water produced during the experiment, and the pressure

Figure 2. HC-PVT experimental device.

Figure 3. High-temperature and high-pressure core displacement experimental device.

monitoring system is mainly used to detect the pressure of the core inlet and outlet.

2.2. Experimental Methods and Steps. *2.2.1. Experiments on Physical Properties of Crude Oil with Different Gas Injection Media.* In order to clarify the influence of different gas injection media on the physical properties of crude oil, the crude oil viscosity experiment, density experiment, gas injection swelling experiment, and saturation pressure experiment were conducted by using the HC-PVT experimental device.

The HC full window high-pressure PVT analyzer was cleaned and vacuumed at 45 °C in the test area. Then a certain amount of crude oil samples in the test area was kept in a single phase and transferred into a PVT device, which was kept at 45 °C for 8 h. First, the sample volume was tested at a rate of 28.5 MPa. Then a certain amount of CO_2 was injected into the formation of crude oil under this pressure, and the system pressure was increased until the CO_2 was completely dissolved. At this time, the system was a single phase. The parameters such as saturation pressure and volume swelling coefficient of CO_2-formation crude oil system were tested. Finally, the CO_2-formation crude oil mixed sample in the PVT device was kept single-phase and transferred to the high-temperature and high-pressure drop-ball viscometer and densimeter, respectively, and the single-phase viscosity and density of the system were tested at 45 °C. Thus, the first aerated swelling experiment was completed. After the PVT instrument was cleaned, the above steps were repeated for the second gas swelling experiment. The amount of CO_2 injected the second time is more than that for the first time. The saturation pressure, volume swelling coefficient, density, and viscosity of the CO_2-formation crude oil system were also tested. Repeatedly, a total of 6 gas swelling experiments were carried out at 45 °C until the molar content of CO_2 in crude oil reached about 60%. The experimental steps of hydrocarbon gas and CH_4 gas were the same as CO_2.

2.2.2. Experiments on Oil Recovery of Different Gas Injection Media. In order to find the best gas injection medium for enhanced oil recovery in the Niuquanhu block, we first carried out the recovery experiments of different gas injection media in the laboratory. The specific experimental steps are as follows:

1. Experimental preparation stage: In this stage, First, we spliced 8−10 cm columnar cores with similar permeability into a 30 cm core model, measured the length and diameter of the spliced core model, and calculated the apparent volume of the core model; Subsequently, we put the core into the core holder, vacuumized the saturated formation water, measured the volume of saturated water, and calculated the core porosity. The core porosity was the volume of saturated water divided by the apparent volume of the core. After saturated water, water was injected into the core at a speed of 0.1 mL/min, and the water permeability of the core was measured. After measuring the water permeability, we put the core holder into the thermostat, and set the thermostat temperature to 45 °C. The back pressure valve was used to set the outlet back pressure to the current formation pressure of 28.5 MPa; Then we saturated the formation oil into the core until there was no water at the outlet of the core, and the oil can be continuously produced. Finally, the volume of saturated oil was measured and the initial oil saturation of the core was calculated.
2. CH_4 gas flooding experiment: After the completion of the experimental preparation stage, we first carried out the core displacement experiment of CH_4 gas. The specific steps were as follows: CH_4 gas was injected into the core at an injection rate of 0.30 mL/min. During the experiment, the oil production and gas production of the core were recorded at intervals, and the gas-oil ratio at the outlet was calculated. The pressure detection system was used to detect the pressure at the inlet and outlet of the core, and the displacement pressure difference was calculated. When the production gas-oil ratio exceeded

5000 mL/mL, the experiment was completed, and the oil recovery of CH_4 gas flooding was calculated.

3. CO_2 gas flooding experiment: Then, we replaced another core model to carry out CO_2 core flooding experiment. The preparation stage of the experiment was the same as (1). In the gas injection and oil displacement stage, we only replaced CH_4 gas with CO_2 gas. The injection rate was still 0.30 mL/min, and the experiment was terminated after the gas-oil ratio exceeded 5000 mL/mL, and the oil recovery of CO_2 flooding was calculated.
4. Hydrocarbon gas flooding experiment: Finally, we carried out a group of hydrocarbon gas core displacement experiment, hydrocarbon gas composition of CH_4 mole content of 65%, C_2−C_4 mole content of 35%. The experimental preparation stage was the same as (1). The injection rate in the gas injection stage was 0.30 mL/min. The experiment was stopped after the gas-oil ratio exceeded 5000 mL/mL, and the oil recovery of hydrocarbon gas flooding was calculated.

2.2.3. Experiments on Influencing Factors of Hydrocarbon Gas Oil Recovery. In order to clarify the influence degree of different factors on hydrocarbon gas flooding oil recovery, we considered five factors such as C_2−C_4 content, back pressure, gas injection rate, permeability, and permeability ratio, and carried out core displacement experiments under different influencing factors in the laboratory. The experimental process was also divided into the core preparation stage and the gas injection flooding stage. The steps of the core preparation stage were the same as described in Section 2.2.2. In the gas injection flooding stage, our specific experimental steps were as follows:

1. Hydrocarbon gas flooding under different C_2−C_4 contents: setting back pressure of 20 MPa, gas injection rate of 0.3 mL/min, and average core permeability of 3.89mD. The injected hydrocarbon gases were changed to hydrocarbon gas 1 (CH_4 content of 85%, C_2−C_4 content of 15%), hydrocarbon gas 2 (CH_4 content of 65%, C_2−C_4 content of 35%), hydrocarbon gas 3 (CH_4 content of 45%, C_2−C_4 content of 55%). The experiment was terminated after the gas-oil ratio exceeded 5000 mL/mL, and the oil recovery of hydrocarbon gas flooding under different C_2−C_4 contents was calculated. And compared with the oil recovery of CH_4 (C_2−C_4 content of 0%) gas flooding.
2. Hydrocarbon gas flooding under different back pressures: using hydrocarbon gas 2 (CH_4 content of 65%, C_2−C_4 content of 35%), setting gas injection rate of 0.3 mL/min, core average permeability of 3.52mD, changing the back pressure of the core outlet end to 10, 15, 20, and 25 MPa, respectively. The experiment was terminated after the gas-oil ratio exceeded 5000 mL/mL, and the oil recovery of hydrocarbon gas flooding under different back pressures was calculated.
3. Hydrocarbon gas flooding under different gas injection rates: hydrocarbon gas 2 (CH_4 content of 65%, C_2−C_4 content of 35%) was used, the back pressure was set to 20 MPa, and the average permeability of the core was 3.56mD. The core gas injection rates were changed to 0.1, 0.2, 0.3, and 0.5 mL/min, respectively. The experiment was terminated after the gas-oil ratio exceeded 5000 mL/mL, and the oil recovery of hydrocarbon gas flooding under different gas injection rates was calculated.
4. Hydrocarbon gas flooding under different permeability: using hydrocarbon gas 2 (CH_4 content of 65%, C_2−C_4 content of 35%), setting back pressure of 20 MPa, gas injection rate of 0.3 mL/min, changing the core permeability to 0.5, 3.54, 10.40, and 44.37 mD, respectively. When the gas-oil ratio exceeded 5000 mL/mL, the experiment was terminated, and the oil recovery of hydrocarbon gas flooding under different permeability was calculated.
5. Hydrocarbon gas flooding under different permeability ratios: in this part, hydrocarbon gas flooding experiments were carried out using heterogeneous cores in the layer. The permeability of the matrix core was 3.54mD, and the permeability ratios were 2.80, 17.67, and 34.92, respectively. Using hydrocarbon gas 2 (CH_4 content of 65%, C_2−C_4 content of 35%), and setting back pressure of 20 MPa, gas injection rate of 0.3 mL/min. The experiment was terminated when the gas-oil ratio exceeded 5000 mL/mL. The oil recovery of hydrocarbon gas flooding under different permeability ratios was calculated and compared with the oil recovery of hydrocarbon gas flooding in homogeneous cores under the same conditions.

3. SPEARMAN RANK CORRELATION COEFFICIENT ANALYSIS OF INFLUENCING FACTORS

In order to clarify the main influencing factors of hydrocarbon gas flooding oil recovery in the Niuquanhu reservoir, based on all the experimental results of 2, Spearman rank correlation coefficient analysis is conducted on five factors, such as C_2−C_4 content, back pressure, gas injection rate, permeability, and permeability ratio. Spearman rank correlation coefficient is a statistical method used to measure the correlation between two sets of data. This method does not depend on the linear correlation of the data and does not consider the overall distribution pattern and sample size of the two variables in the calculation process. It is based on the level of data rather than the original value. So there is no specific requirement for the distribution of data, and it is robust to outliers. It is usually denoted by the letter "ρ", and its value is between −1 and 1. The specific calculation steps are as follows:

First, combine the four sets of data points corresponding to each influencing factor are combined into a dataframe, where each column represents a variable. The data points corresponding to the influencing factors are represented by X_i, and the data points corresponding to the oil recovery are represented by Y_i. Each group of data is hierarchically processed, which means sorting the data by size and assigning rankings to them. If there are duplicate values, then the average ranking can be used.

For each pair of data points, we calculate their rank difference within the two sets of ranked data. The rank difference is denoted as

$$d_i = X_i - Y_i \tag{1}$$

Calculating the sum of squared rank differences $\sum_{i=1}^{n} d_i^{\,2}$.

Finally, according to the formula:

$$\rho_n = 1 - \frac{6\sum_{i=1}^{n} d_i^{\,2}}{n(n^2 - 1)} \tag{2}$$

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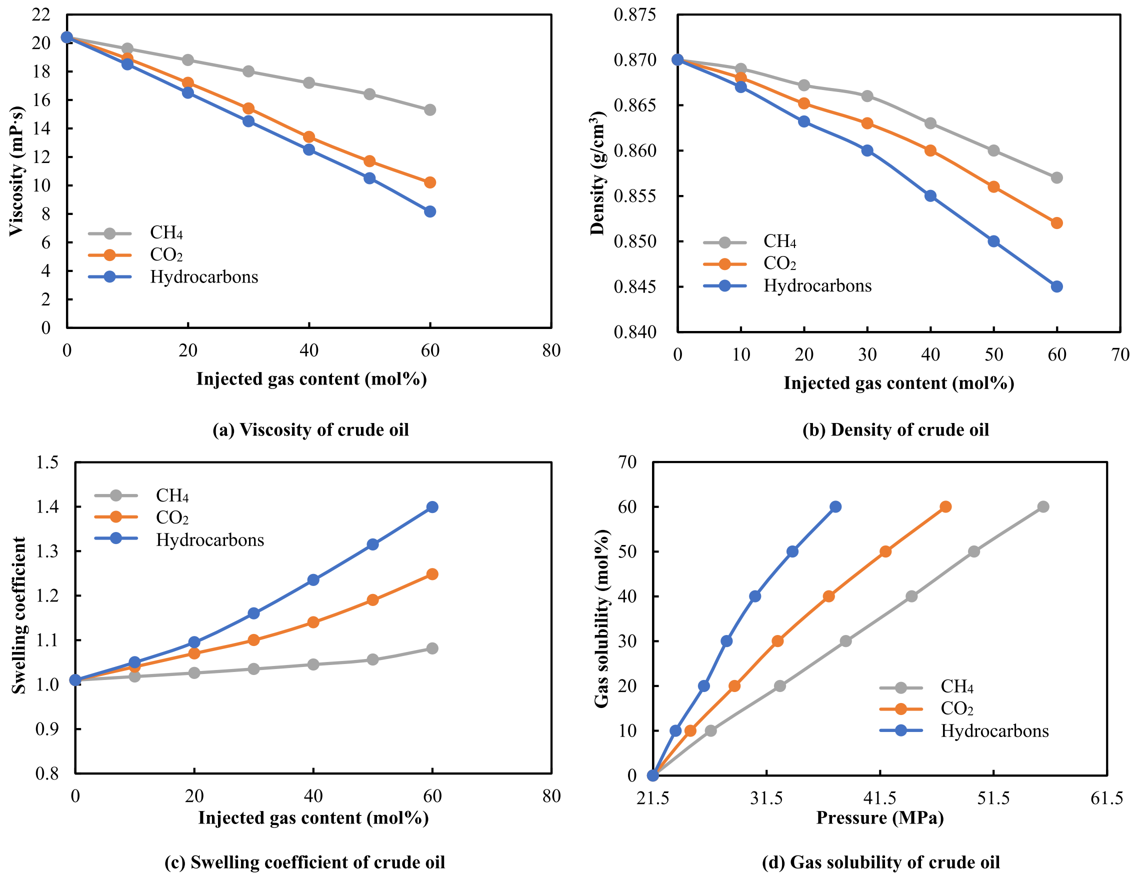

Figure 4. Analysis of physical properties of crude oil with different injected gases. (a) Viscosity of crude oil. (b) Density of crude oil. (c) Swelling coefficient of crude oil. (d) Gas solubility of crude oil.

The Spearman rank correlation coefficients of C_2−C_4 content, back pressure, gas injection rate, permeability, and permeability ratio are obtained ρ_1, ρ_2, ρ_3, ρ_4, and ρ_5, respectively. In the formula, n represents the number of data points, and ρ_n represents the Spearman rank correlation coefficient.

Based on the positive, negative, and proximity of the calculation results, the strength and direction of the linear relationship between the two variables can be judged. If ρ_i is positive, it means a positive correlation, and the closer it is to 1, the stronger the positive correlation; If ρ_i is negative, it means a negative correlation, and the closer it is to −1, the stronger the negative correlation; If ρ_i is close to zero, it means that the relationship between the two variables is weaker or there is no linear relationship. Therefore, when comparing the influence degree of the main control factors, only the size of the $|\rho_i|$ comparison is needed. The larger the $|\rho_i|$ is, the greater the influence degree of the main control factors on oil recovery is. And the smaller the $|\rho_i|$ is, the smaller the influence degree of the main control factors on oil recovery is.

4. RESULTS AND DISCUSSION

4.1. Analysis of Physical Properties of Crude Oil with Different Injected Gases. In order to study the influence of different injected gas media on the physical properties of crude oil. Viscosity, density, swelling coefficient, and gas solubility of crude oil are measured respectively after injection of different injected gas media. The physical property analysis of crude oil with different injected gas is shown in Figure 4. According to the results of Figure 4a, when 60% mol of hydrocarbon gas, CO_2, and CH_4 gas are injected, respectively, the viscosity of crude oil decreases by 60, 50, and 25% respectively. Therefore, it is concluded that the influence of different gas injection media on the viscosity of crude oil is ranked as follows: hydrocarbon gas > CO_2 > CH_4. According to the results of Figure 4b, when 60% mol of hydrocarbon gas, CO_2, and CH_4 gas are injected, respectively, the density of crude oil decreases by 2.9, 2.1, and 1.5% respectively. Therefore, it is concluded that the crude oil density is minimally affected by the three different gas injection media. According to the results of Figure 4c, when 60% mol % hydrocarbon gas, CO_2, and CH_4 gas are injected respectively, the swelling coefficient of crude oil increases by 38.5, 23.5, and 7% respectively. Therefore, it is concluded that the influence of different gas injection media on the swelling coefficient of crude oil is ranked as follows: hydrocarbon gas > CO_2 > CH_4. According to the results of Figure 4d, Under the same saturation pressure, the order of gas solubility of crude oil is ranked as follows: hydrocarbon gas > CO_2 > CH_4.

4.2. Optimization of Gas Injection Media for Low Permeability and Medium Viscosity Crude Oil Reservoirs. In order to clarify the best injection medium for gas injection to enhance oil recovery in "low permeability and medium viscosity crude oil" reservoirs, we carry out the oil recovery experiments of CH_4 gas flooding, CO_2 gas flooding, and hydrocarbon gas flooding, respectively. According to Figure 5a, the result shows that when the injected PV value exceeds 0.48 PV, the oil recovery of hydrocarbon gas flooding is significantly higher than that of CO_2 gas flooding and CH_4

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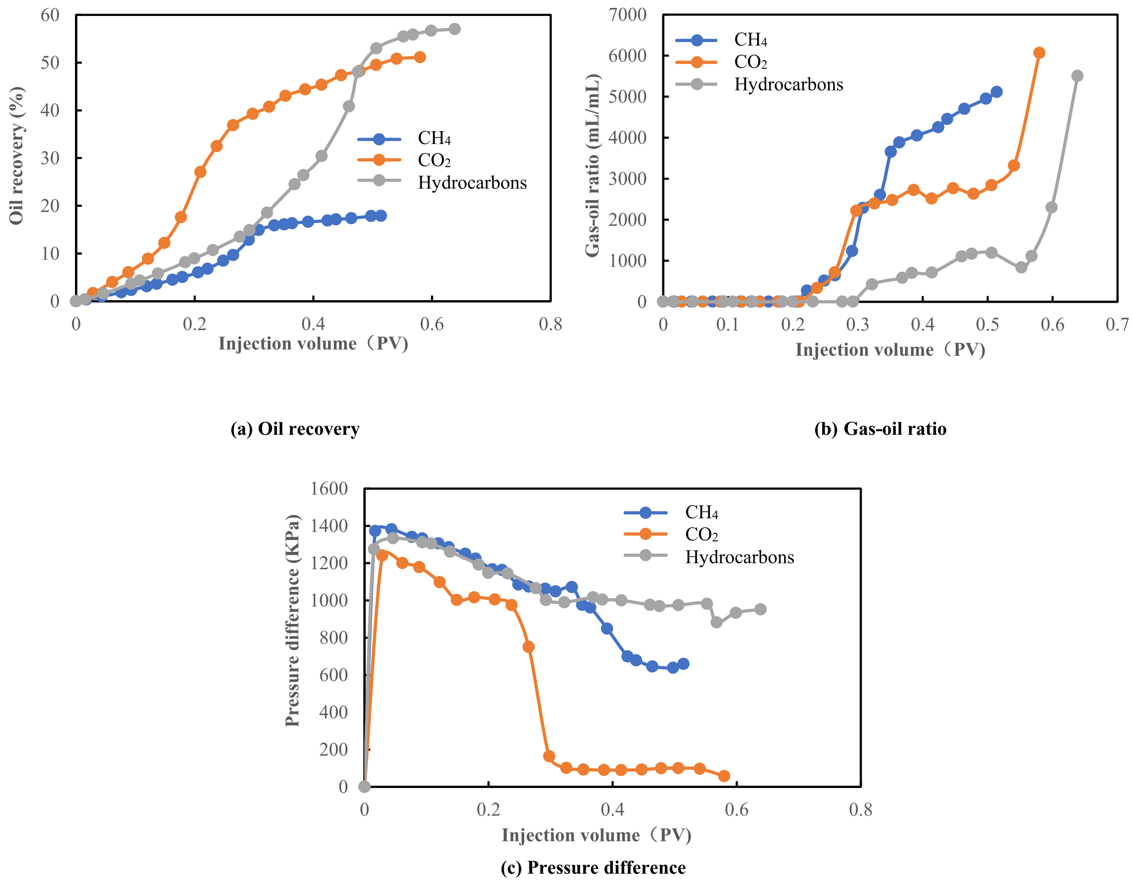

Figure 5. Comparison of production dynamic curves of different gas injection media (Experimental condition: 45 °C, 20 MPa, 0.3 mL/min. MMP of CO_2 and crude oil: 25.7 MPa). (a) Oil recovery, (b) gas−oil ratio, and (c) pressure difference.

gas flooding. Under the formation conditions, the oil recovery of hydrocarbon gas flooding finally reaches 57%, the oil recovery of CO_2 gas flooding finally reaches 51%, and the oil recovery of CH_4 gas flooding finally reaches 18%. The CO_2 curve is obviously different from that of CH_4 and hydrocarbon gas. The oil recovery of CO_2 gas flooding is higher in the early and middle stages. The oil recovery of CH_4 gas flooding and hydrocarbon gas flooding is not very high in the early and middle stages, and it increases rapidly only in the late stage. According to Figure 5b, the result shows that CH_4 first gas appearance and gas channeling.[20] When CH_4 contains hydrocarbon gas, the time of gas appearance and gas channeling is greatly prolonged, and the three gases are in the period of oil and gas coproduction for most of the time during core displacement. According to Figure 5c, the result shows that when the displacement pressure difference curve begins to rise rapidly, it corresponds to the initial stage of the recovery curve, that is, the oil recovery steep rise stage. The injected gas first slowly dissolves in the crude oil and slowly accumulates energy. When it reaches the highest point, the oil production rate rises sharply and the oil recovery increases rapidly. When the displacement pressure difference curve reaches the highest point and then decreases slowly, corresponding to the front and middle sections of the oil recovery curve, the oil production rate gradually decreases at this time, but the gas has not yet broken through, that is, there is no gas at the outlet end. The pressure in the second half of the displacement pressure difference curve decreases rapidly. Taking CO_2 gas flooding as an example, the rapidly decreasing pressure difference point actually corresponds to the point where gas appears at the outlet end. At the same time, on the oil recovery curve, the rapidly decreasing pressure difference point also corresponds to the inflection point at which the oil recovery curve begins to flatten, which means that gas and oil are produced at the same time after gas breakthrough and the oil production rate is greatly reduced. The displacement pressure difference between hydrocarbon gas and CH_4 gas, even at the end of the decline, but their decline is not as high as the decline of CO_2, and corresponding to the gas−oil ratio curve, the gas−oil two-phase production period of hydrocarbon gas flooding is obviously longer than that of CO_2 flooding, which means that hydrocarbon gas can always interact with crude oil components during the experimental period to improve oil recovery. The interaction between the CO_2 gas and crude oil will be obviously weakened as long as the gas appears.

First of all, CO_2 and crude oil are usually multiple contact miscible flooding, the MMP of CO_2 and crude oil is 25.7 MPa, while CH_4 gas and crude oil can not be miscible, hydrocarbon gas is a contact miscible.[21] The interaction mechanism between different gases and crude oil is also completely different. The relationship between the interaction ability of different gases and crude oil is hydrocarbon gas > CO_2 > CH_4. From the perspective of immiscible flooding dissolution and extraction, hydrocarbon gas usually has high oleophilicity compared with CO_2 and CH_4 and has high similarity and good compatibility with hydrocarbon molecules in crude oil. According to the principle of similar miscibility,[22] hydrocarbon

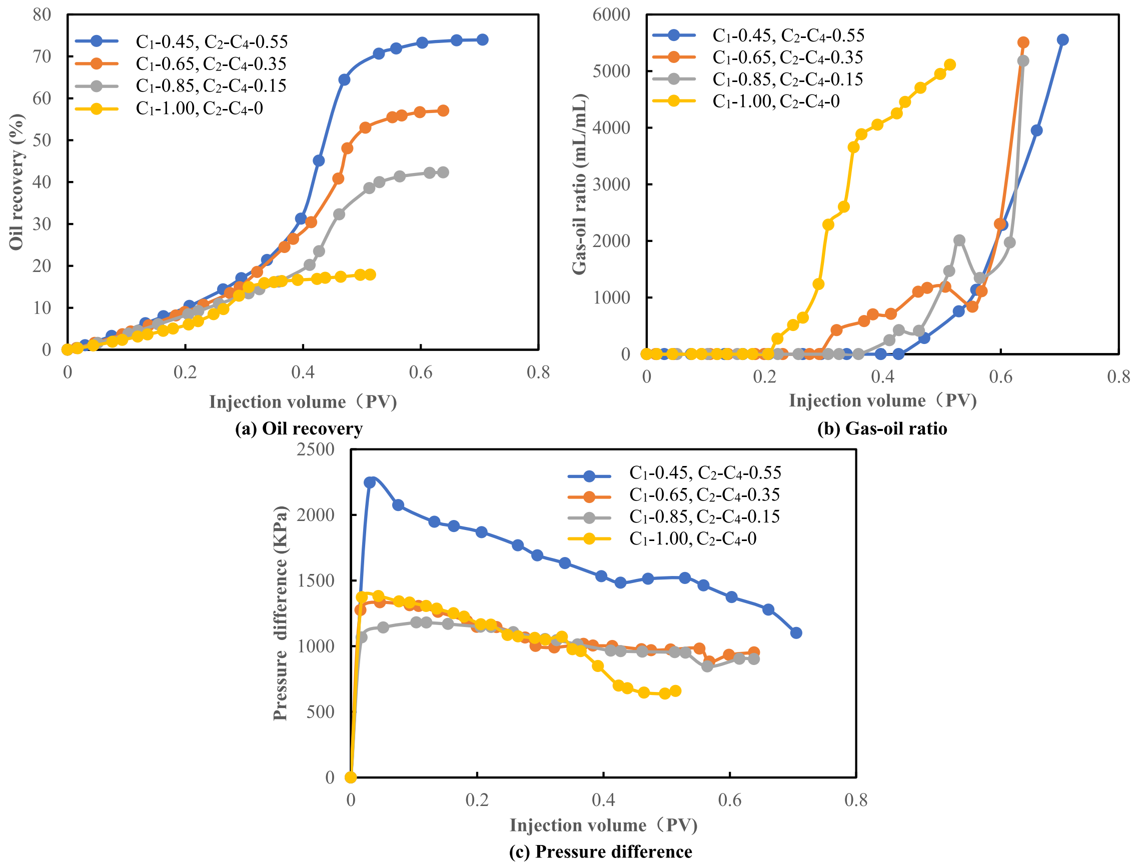

Figure 6. Comparison of production dynamic curves of different C_2−C_4 contents. (a) Oil recovery, (b) gas−oil ratio, and (c) pressure difference.

gas can more effectively dissolve hydrocarbon components in crude oil, reduce the viscosity of crude oil, improve fluidity, and thus increase oil recovery. Second, the viscosity of crude oil in the Niuquanhu reservoir is 20 mPa s, which is a medium viscosity crude oil. Due to the higher viscosity of crude oil, the more heavy components are in it. An important mechanism of CO_2 immiscible flooding is that it can extract and draw light hydrocarbon components. After CO_2 is injected, CO_2 first extracts the light hydrocarbon components in crude oil and then outputs them. Therefore, the oil recovery of CO_2 is the highest in the early and middle stages. However, after the gas appearance and gas channeling, the interaction between CO_2 and heavy components in crude oil is obviously weakened. Therefore, when gas and oil are produced at the same time, the oil displacement effect of CO_2 is not as good as that of hydrocarbon gas.[23] Then, hydrocarbon gas originally belonged to the components of crude oil, which are more easily dissolved in crude oil, so the increase of early and middle stages recovery is lower, and the gas breakthrough time is the latest, indicating that this is a slow dissolution process; after gas breakthrough, a large amount of crude oil is produced with the dissolved gas of C_1−C_4, and the oil recovery is greatly increased, and the oil and gas coproduction time of hydrocarbon gas is longer than that of the other two gases, indicating that the dissolved gas is more.[24] Finally, although CH_4 also belongs to the crude oil component, it is quite different from the heavy component of crude oil. CH_4 can be dissolved some, but not much. This means that CH_4 cannot effectively dissolve heavy hydrocarbon molecules in crude oil, thereby decreasing the viscosity of the crude oil. That is, the solubility of CH_4 limits its ability to reduce the viscosity of crude oil, so the oil recovery is the lowest.[25] By comparing the oil recovery, gas−oil ratio, and displacement pressure difference of three gas injection media, the hydrocarbon gas is eventually optimized as the gas injection medium for improving the oil recovery of low permeability and medium viscosity crude oil in Niuquanhu.

4.3. Analysis of Different Influencing Factors of Hydrocarbon Gas Flooding.

4.3.1. Analysis of Influencing Factors of C_2−C_4 Content. The influence of the C_2−C_4 content factor on the oil displacement effect of hydrocarbon gas is studied, and the production dynamic comparison diagram of the oil recovery, gas−oil ratio, and displacement pressure difference under different C_2−C_4 content is obtained, as shown in Figure 6. According to the results of Figure 6a, the oil recovery is the highest when the content of C_2−C_4 is 55%, which can reach 74%. The oil recovery of CH_4 is the lowest, which can reach 18%. According to Figure 6b, the result shows CH_4 gas first gas appearance and gas channeling. When CH_4 contains C_2−C_4 components, the time of gas appearance and gas channeling is greatly prolonged, and the three gases are in the oil and gas coproduction period for most of the time in the core displacement process. According to Figure 6c, the result shows that the gas displacement pressure difference increases with the increase in the C_2−C_4 content.

First of all, the higher the content of C_2−C_4 is, on the one hand, it can improve the fluidity of crude oil and reduce the viscosity of crude oil. On the other hand, the higher the content of C_2−C_4 is, the stronger its ability to dissolve crude oil and interact with heavy components is.[26] Under the simultaneous action of the two aspects, the oil recovery is further improved. Second, because the relative solubility of

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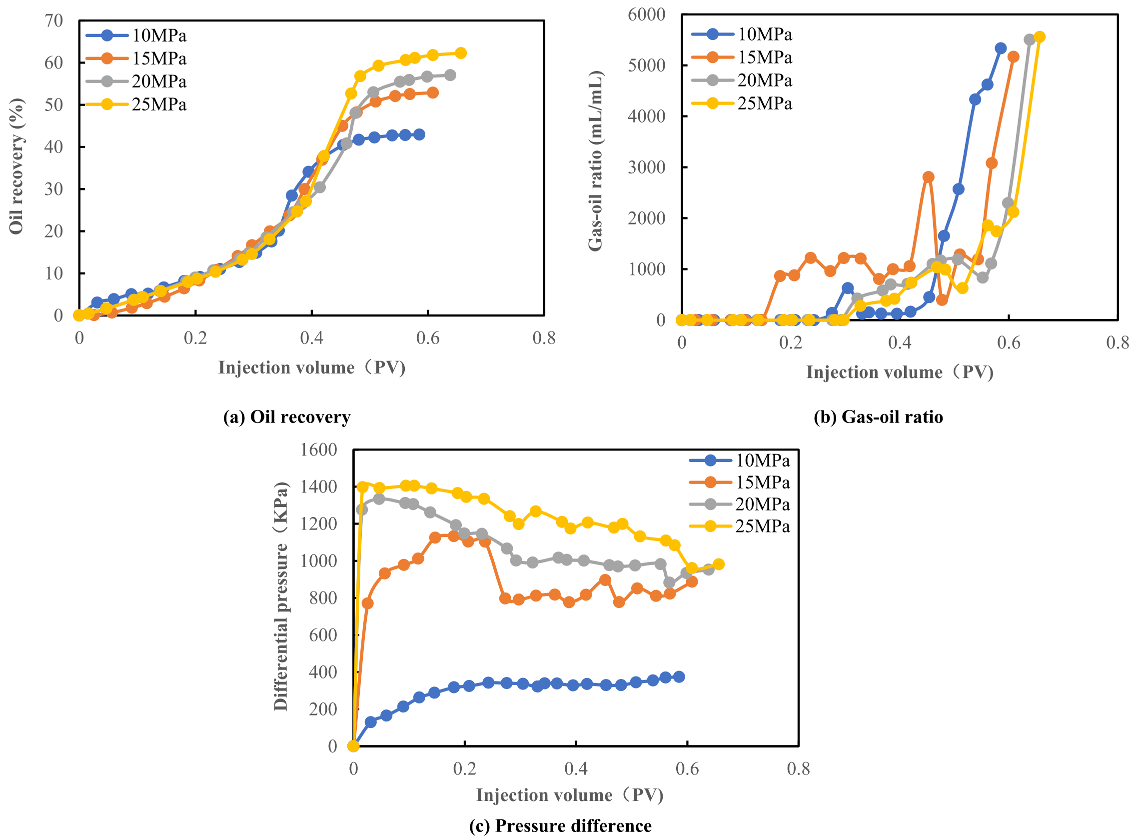

Figure 7. Comparison of production dynamic curves of different back pressures. (a) Oil recovery, (b) gas−oil ratio, and (c) pressure difference.

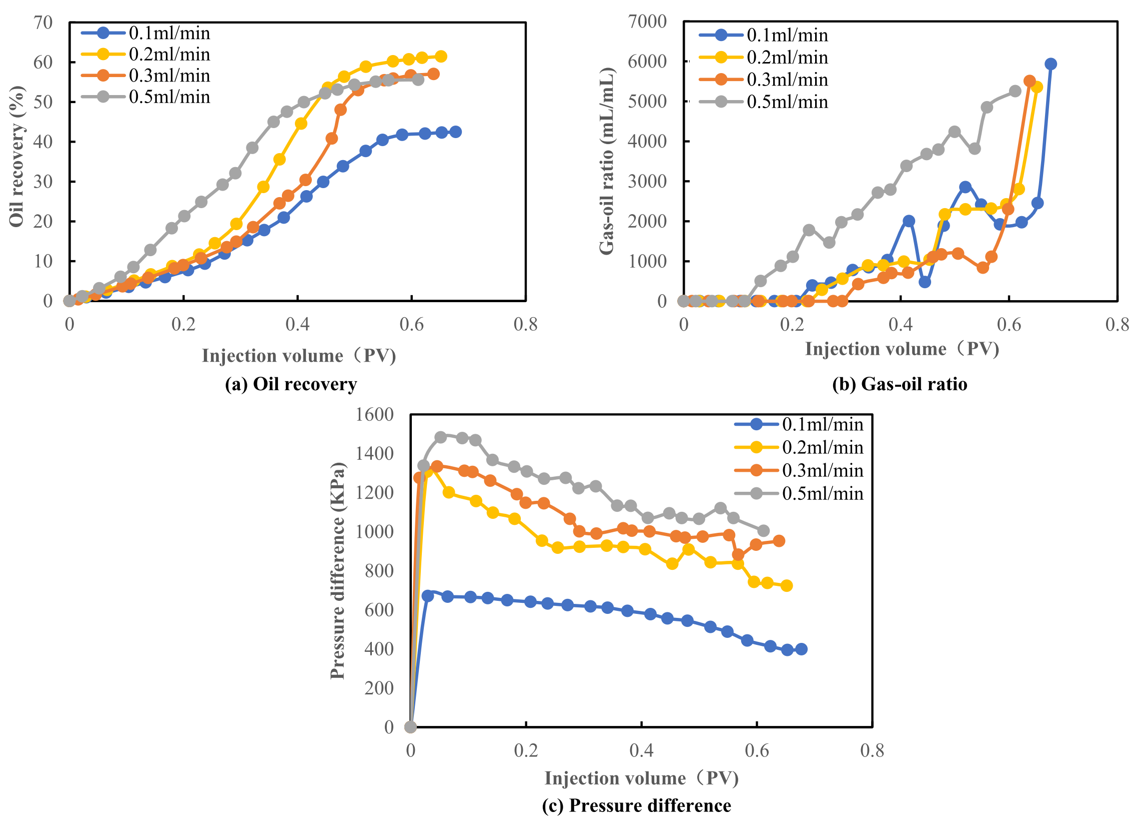

Figure 8. Comparison of production dynamic curves of different gas injection rates. (a) Oil recovery, (b) gas−oil ratio, and (c) pressure difference.

CH_4 in crude oil is relatively low, it means that CH_4 gas cannot dissolve well in crude oil like hydrocarbon gas, and the addition of the C_2−C_4 component will greatly improve the relative solubility of CH_4 in crude oil.[27] In the process of oil

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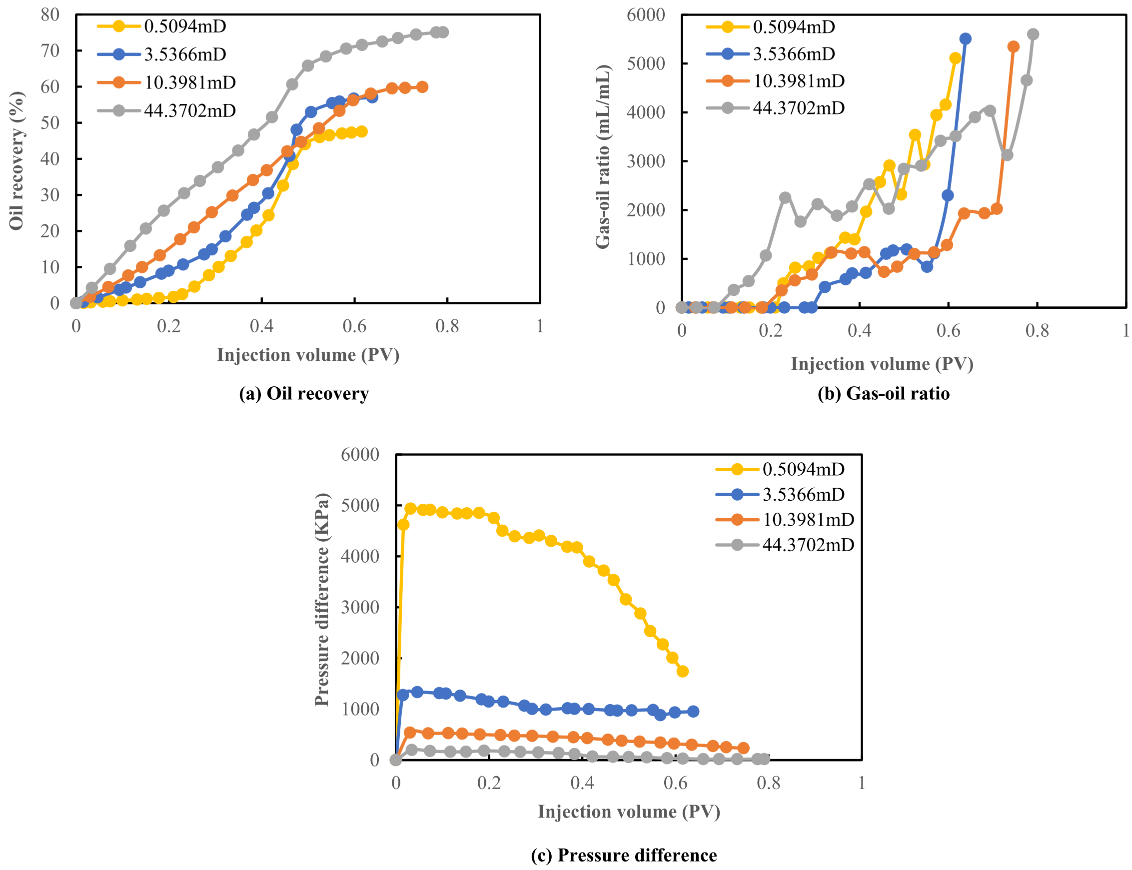

Figure 9. Comparison of production dynamic curves of different permeability. (a) Oil recovery, (b) gas–oil ratio, and (c) pressure difference.

displacement, if the injected gas cannot be fully dissolved in crude oil, it will lead to the penetration and movement of the gas phase, resulting in the phenomenon of gas appearance and gas channeling. Finally, since hydrocarbon gases show poor wettability on the rock surface, it means that it is not easy for them to cover the pore surface of the rock and push the crude oil forward. In contrast, CH_4 gas can better wet the pore surface of rock under the same condition, so hydrocarbon gas needs higher displacement pressure than CH_4 gas to drive crude oil.[28]

4.3.2. Analysis of Influencing Factors of Back Pressure. The influence of the back pressure factor on the oil displacement effect of hydrocarbon gas is studied, and the production dynamic comparison diagram of the oil recovery, gas-oil ratio, and displacement pressure difference under different back pressures is obtained, as shown in Figure 7. According to the results of Figure 7a, the oil recovery is the highest when the back pressure is 25 MPa, which can reach 62%. When the back pressure is 10 MPa, the oil recovery is the lowest, which can reach 43%. According to Figure 7b, the result shows that the higher the back pressure, the later the gas channeling time is. In the process of core displacement, most of the time is in the period of oil and gas coproduction. According to Figure 7c, the result shows that the pressure difference of the gas displacement increases with the increase of back pressure.

First, hydrocarbon gas is more easily dissolved in crude oil. The higher the pressure is, the stronger the nature of hydrocarbon gas dissolving crude oil is, and the higher the oil recovery is.[29] Second, the increase of back pressure will lead to the increase of total pressure in the reservoir, thus reducing the pressure gradient in the underground reservoir. A smaller pressure gradient means that the driving force of hydrocarbon gas in the reservoir displacement is small, so the movement speed of gas will slow down, which makes the gas channeling time become longer.[30] Finally, high back pressure will increase the gas displacement pressure difference, because high back pressure makes it easier for the liquid hydrocarbon molecules in the crude oil to remain stable, reducing the formation of bubbles in the liquid crude oil, which will reduce the relative fluidity of the crude oil, making it easier for the gas to push in the liquid crude oil, thus increasing the displacement pressure difference.[31]

4.3.3. Analysis of Influencing Factors of the Gas Injection Rate. The influence of the gas injection rate factor on the oil displacement effect of hydrocarbon gas is studied, and the production dynamic comparison diagram of the oil recovery, gas-oil ratio, and displacement pressure difference under different gas injection rates is obtained, as shown in Figure 8. According to Figure 8a, the result shows that the oil recovery is the highest when the gas injection rate is 0.2 mL/min, which can reach 61%. When the gas injection rate is 0.1 mL/min, the oil recovery is the lowest, which can reach 42%. According to Figure 8b, the result shows that the higher the gas injection rate, the earlier the gas channeling time is. Most of the time in the process of core displacement is in the period of oil and gas coproduction. According to Figure 8c, the result shows that the pressure difference of gas displacement increases with the increase in gas injection rate.

First, when the injection rate of hydrocarbon gas increases in the early stage, the gas forms a strong leading edge, which can more effectively push crude oil, thus greatly increasing the oil

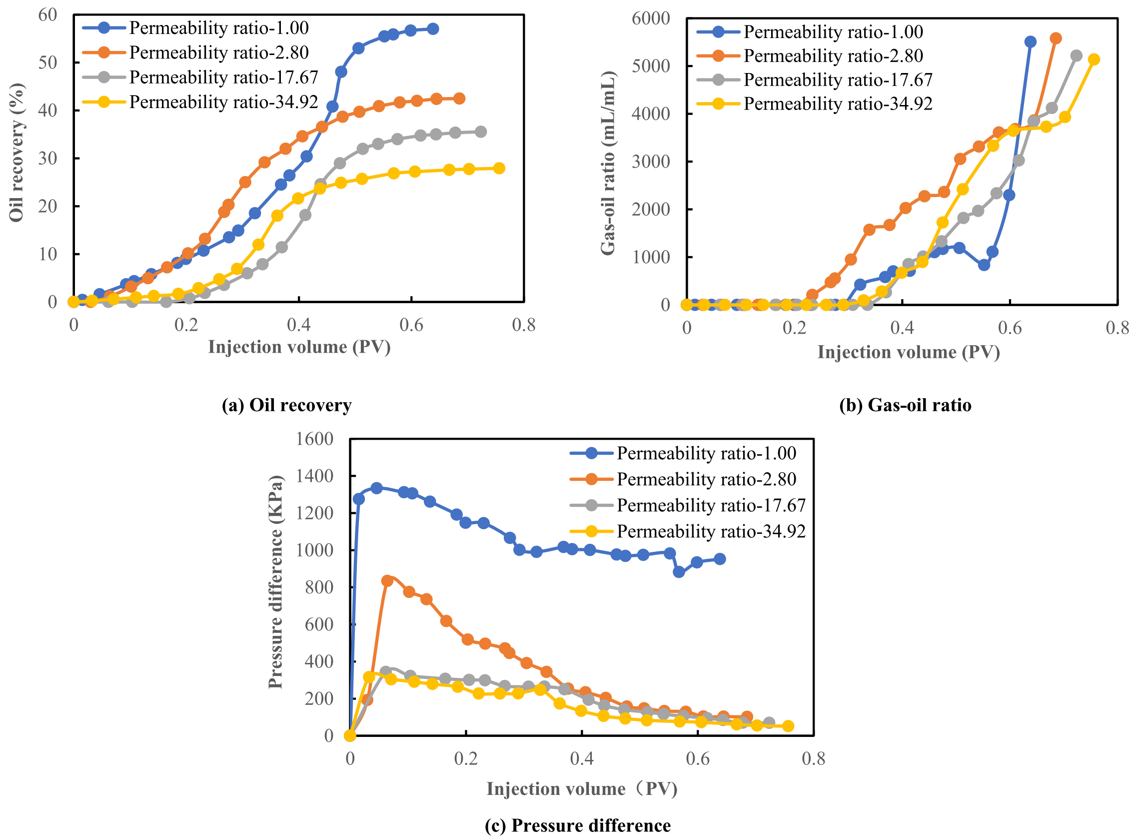

Figure 10. Comparison of production dynamic curves of different permeability ratios. (a) Oil recovery, (b) gas–oil ratio, and (c) pressure difference.

recovery. In the later period, with the increase of gas injection rate, due to the excessive speed, the gas may not be fully dissolved in the crude oil, resulting in more gas channeling out rather than driving the crude oil, which makes the oil recovery decrease.[32] Second, the high gas injection rate leads to a steeper pressure gradient at the faster gas front, and this steep pressure gradient can push the gas into the reservoir more effectively, thus rapidly forming a gas channel. Gas can penetrate reservoir rocks more quickly, resulting in gas channeling occurring earlier.[33] Finally, as the gas injection rate increases, the reason why the gas displacement pressure difference increases is that the rapid advance of the leading edge of the gas will form a steep pressure gradient.[30] This pressure gradient can more effectively push gas through the reservoir, thereby increasing the displacement pressure difference between the gas and crude oil.

4.3.4. Analysis of Influencing Factors of Permeability. The influence of the permeability factor on the oil displacement effect of hydrocarbon gas is studied, and the production dynamic comparison diagram of the oil recovery, gas–oil ratio, and displacement pressure difference under different permeability is obtained, as shown in Figure 9. According to the result of Figure 9a, the oil recovery is the highest when the permeability is 44.3702 mD, which can reach 75%. When the permeability is 0.5094 mD, the oil recovery is the lowest, which can reach 48%. At the initial stage of the core displacement experiment, when the injection volume of hydrocarbon gas does not exceed 0.2 PV, first, it is difficult for crude oil to be flooded by hydrocarbon gas due to the low permeability of the core. Second, because the hydrocarbon gas composition is similar to the crude oil composition, and the crude oil viscosity is high. Therefore, in the initial stage of the experiment, a large amount of hydrocarbon gas dissolves in crude oil. There is not enough hydrocarbon gas accumulation to flood crude oil. The above two reasons led to the oil recovery of 0.5 mD at 0.2 PV being almost nil, while there is no significant pressure build-up. According to Figure 9b, the result shows that the higher the permeability is, the later the gas channeling time is. Most of the time in the process of core displacement is in the period of oil and gas coproduction. According to Figure 9c, the result shows that the gas displacement pressure difference decreases with an increase in permeability.

First, the heterogeneity of the low permeability core in Niuquanhu is serious, which makes the distribution and flow of hydrocarbon gas complicated and affects the oil recovery of hydrocarbon gas flooding.[34] Second, the higher the permeability is, the greater the seepage speed is, the more pores and channels in the rock, and the faster the gas can pass through these channels, thus increasing the gas migration velocity.[35] Therefore, the formation with a high permeability allows gas to push crude oil faster, resulting in a relatively late gas channeling time. Finally, with the increase of permeability, the reason why the gas displacement pressure difference is reduced is that when the permeability is high, the reservoir rock is easier to let the fluid pass through, so the flow resistance is small.[36] This means that the gas will encounter less resistance in the high permeability formation and the flow rate is faster so that the displacement pressure difference required in the gas flooding process will be reduced.

4.3.5. Analysis of Influencing Factors of the Permeability Ratio. The influence of the permeability ratio factor on the oil displacement effect of hydrocarbon gas is studied, and the production dynamic comparison diagram of the oil recovery, gas-oil ratio, and displacement pressure difference under different permeability ratios is obtained, as shown in Figure 10. According to the result of Figure 10a, the oil recovery is the highest when the permeability ratio is 1, which can reach 57%. When the permeability ratio is 34.92, the oil recovery is the lowest, which can reach 28%. According to Figure 10b, the result shows that the larger the permeability ratio, the later the gas channeling time is. Most of the time in the process of core displacement is in the period of oil and gas coproduction. According to Figure 10c, the result shows that the gas displacement pressure difference decreases with the increase in permeability ratio.

First, the permeability ratio leads to the uneven distribution of gas between different regions, which may lead to the rapid passage of gas through the high permeability region, while the crude oil displacement effect in the low permeability region is poor, thus reducing the overall oil recovery.[37] Second, the permeability of low permeability regions is poor, and the gas migration rate in these regions is slow, which means that it takes more time for the gas to fully drive the crude oil and form gas channeling. In the high permeability region, the gas may drive the crude oil faster, but in the low permeability region, the displacement rate is slower, so the gas channeling time is delayed.[38] Finally, as the permeability ratio increases, the gas displacement pressure difference will decrease. Because the smaller the permeability ratio is, the more difficult it is for the gas to pass through the pores and channels of the rock, so it cannot effectively push the crude oil, which will increase the gas displacement pressure difference.[39] In contrast, the larger the permeability ratio, the better the permeability of the rock to the gas, which may lead to the faster migration of the gas in the low permeability regions, so only a lower displacement pressure difference is required.

4.4. Analysis of the Main Controlling Factors of Hydrocarbon Gas Flooding. Taking oil recovery as the evaluation index, the oil recovery change amplitude is defined as ΔR, and the final oil recovery change amplitude of different influencing factors is compared, as shown in Table 5:

$$\begin{aligned}\Delta R_{C_2-C_4\text{ content}} &> \Delta R_{\text{Permeability ratio}}\\ &> \Delta R_{\text{Permeability}}\\ &> \Delta R_{\text{Back pressure}}\\ &> \Delta R_{\text{Gas injection rate}}\end{aligned}$$

Therefore, the C_2-C_4 content has the greatest influence in the analysis experiment of hydrocarbon flooding influencing factors in Niuquanhu. The permeability ratio is the second-order influencing factor; the permeability is the third-order influencing factor; the back pressure is the fourth-order influencing factor; and the gas injection rate has the lowest influence.

In order to provide a more accurate evaluation of the main control factors, we used the Spearman rank correlation coefficient method to deal with the above problems. Taking the five influencing factors of C_2-C_4 content, back pressure, gas injection rate, permeability, and permeability ratio as input and the oil recovery as output, the influencing factors of hydrocarbon gas flooding are normalized by the Spearman rank correlation coefficient method. After normalization, all input parameters are dimensionless parameters, and "normalized parameter" is redefined as "λ", and "normalized oil recovery" is redefined as "η". All parameter values are from −1 to 1, and the greater the absolute value of the value is, the stronger the influence of the factor is. According to Figure 11, the result shows that

Table 5. Comparison of the Oil Recovery Change Amplitude of Different Influencing Factors

core number	experimental condition		oil recovery (%)	ΔR (%)
1	C_2-C_4 content (%)	0	17.90	56.05
2		15	42.29	
3		35	57.02	
4		55	73.95	
5	back pressure (MPa)	10	42.93	19.33
6		15	52.87	
7		20	57.02	
8		25	62.26	
9	gas injection rate (mL/min)	0.1	42.47	18.96
10		0.2	61.43	
11		0.3	57.02	
12		0.5	55.58	
13	permeability (mD)	0.5094	47.55	27.51
14		3.5366	57.02	
15		10.3981	59.89	
16		44.3702	75.06	
17	permeability ratio	1.00	57.02	29.11
18		2.80	42.47	
19		17.67	35.53	
20		34.92	27.91	

$$\begin{aligned}|\eta_{C_2-C_4\text{ content}}| &> |\eta_{\text{Permeability ratio}}|\\ &> |\eta_{\text{Permeability}}|\\ &> |\eta_{\text{Back pressure}}|\\ &> |\eta_{\text{Gas injection rate}}|\end{aligned}$$

Therefore, $\lambda_{C_2-C_4\text{ content}}$ has the greatest influence in the analysis experiment of hydrocarbon flooding influencing factors in Niuquanhu. The $\lambda_{\text{Permeability ratio}}$ is the second-order influencing factor, the $\lambda_{\text{Permeability}}$ is the third-order influencing factor, the $\lambda_{\text{Back pressure}}$ is the fourth-order influencing factor, and the $\lambda_{\text{Gas injection rate}}$ has the lowest influence. The permeability ratio and permeability have a great influence on oil recovery. The mechanism of the permeability ratio is that the gas is easier to pass through in the high permeability region, while the gas permeability is poor in the low permeability region. The permeability ratio leads to the uneven distribution of gas between different regions, which may lead to the rapid passage of gas through the high permeability region, while the crude oil displacement effect in the low permeability region is poor, thus affecting the overall oil recovery. The influence mechanism of permeability is that the heterogeneity of the low-permeability core in Niuquanhu is serious, which makes the distribution and flow of hydrocarbon gas complicated and affects the oil recovery of hydrocarbon flooding.

According to the results in Table 6, the results of the traditional ranking analysis of influencing factors are the same as those of the Spearman rank correlation coefficient method. Therefore, we believe that the accuracy of the ranking results

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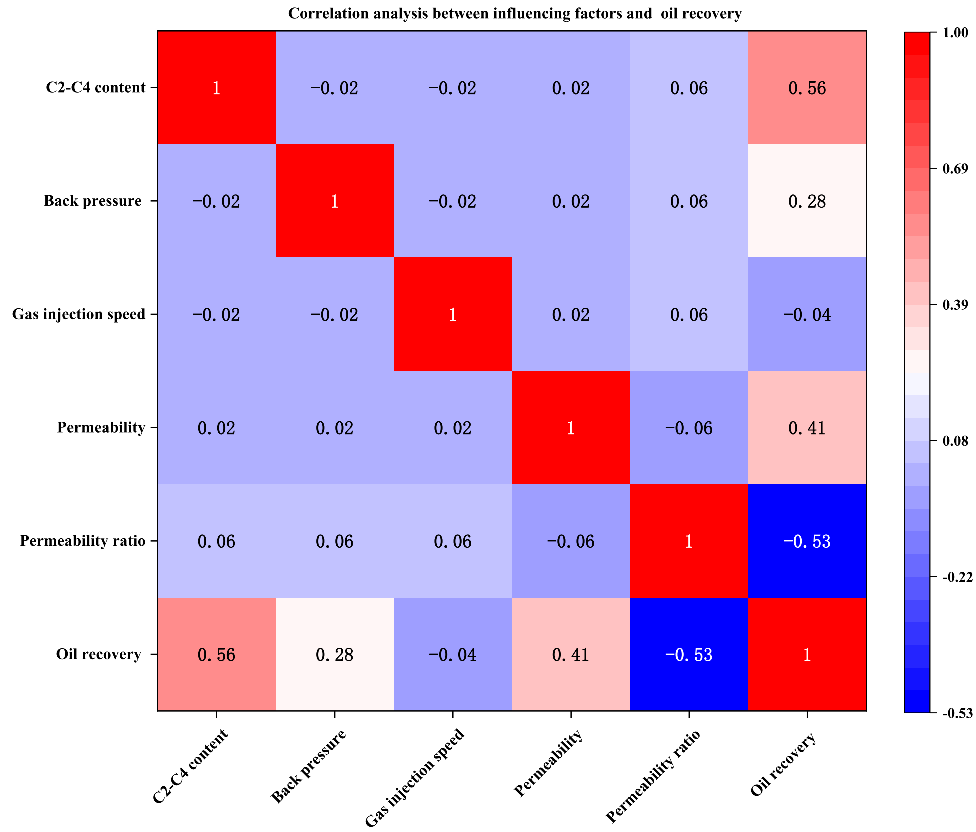

Figure 11. Correlation analysis between influencing factors and oil recovery.

Table 6. Comparison of the Results of Different Analysis Methods of Influencing Factors

	C_2-C_4 content	back pressure	gas injection rate	permeability	permeability ratio
ΔR	56.05%	19.33%	18.96%	27.51%	29.11%
η	0.56	0.28	−0.04	0.41	−0.53

of traditional influencing factors is further verified by the Spearman rank correlation coefficient method.

To maximize the effect of gas injection flooding in "low permeability and medium viscosity crude oil" reservoirs, meticulous control of the following influencing factors is essential based on their ranking results. Here are some suggestions for controlling these factors: First, a suitable C_2-C_4 hydrocarbon gas mixture is opted to meet the reservoir's characteristics. Higher C_2-C_4 content typically enhances the crude oil solubility and interfacial tension, facilitating the movement of the crude oil. Additionally, the permeability ratio refers to the variation in permeability across diverse reservoir regions. Understanding this difference prevents excessive gas injection in high-permeability regions and ensures adequate injection in low-permeability regions. Different gas injection strategies need to be adopted in different regions to maximize the flow of crude oil to the wellhead. Finally, it is very important to adjust the gas injection rate in time according to permeability, back pressure, and reservoir characteristics to achieve maximum oil recovery. Studying the influencing factors of hydrocarbon gas flooding is very important for optimizing the crude oil production process, improving oil recovery, reducing costs, extending reservoir life, and reducing environmental impact in "low permeability and medium viscosity crude oil" reservoirs. These studies contribute to a more scientific, efficient, and sustainable exploitation of crude oil resources in "low permeability and medium viscosity crude oil" reservoirs. This has greatly promoted the competitiveness and sustainability of such reservoirs.

5. CONCLUSIONS

In the PVT experiment, the influence of different gas injection media on the physical properties of crude oil was investigated. In the experiment of hydrocarbon gas core displacement, the oil displacement effect of different gas injection media and the different influencing factors of hydrocarbon gas displacement are analyzed, respectively. The influencing factors mainly include C_2-C_4 content, back pressure, permeability, permeability ratio, and gas injection rate, and the five influencing factors are ranked by the degree of influence. The conclusions are as follows:

1. According to the PVT experimental results, the influence of different injected gas media on the physical properties of crude oil is as follows. The influence of different gas injection media on the viscosity of crude oil is ranked as follows: hydrocarbon gas > CO_2 > CH_4. The crude oil density is minimally affected by the three different gas injection media. The influence of different gas injection media on the swelling coefficient of crude oil is ranked as follows: hydrocarbon gas > CO_2 > CH_4. Under the same saturation pressure, the order of gas solubility of crude oil is ranked as follows: hydrocarbon gas > CO_2 > CH_4.
2. Hydrocarbon gas oil recovery is significantly higher than CO_2 oil recovery and CH_4 oil recovery. It is because the higher content of C_2-C_4 components can not only improve the fluidity of crude oil but also reduce the viscosity of crude oil. Moreover, hydrocarbon gas can

not only enhance the solubility of C_2-C_4 components and crude oil but also enhance their interaction with heavy components. This greatly improves the recovery of crude oil.

3. Using the Spearman rank correlation coefficient method, the influencing factors of enhanced oil recovery by hydrocarbon gas flooding are determined. The order of influence degree is as follows: C_2-C_4 content > permeability ratio > permeability > back pressure > gas injection rate.
4. Among the three injection gas media, hydrocarbon gas has the best effect of dissolving in crude oil. It can not only greatly reduce the viscosity and density of crude oil, but also greatly swell the volume of crude oil. Thus, the fluidity of crude oil can be improved and the oil recovery can be enhanced. Hydrocarbon gas is the best injection gas medium for low permeability and medium viscosity crude oil reservoirs, and the content of C_2-C_4 in hydrocarbon gas is the most important factor affecting hydrocarbon gas flooding. Therefore, hydrocarbon gas flooding is a gas injection method worth considering for greatly enhancing oil recovery in "low permeability and medium viscosity crude oil" reservoirs.

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Notes

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