

Laboratory Study on the Oil Displacement Process in Low-Permeability Cores with Different Injection Fluids

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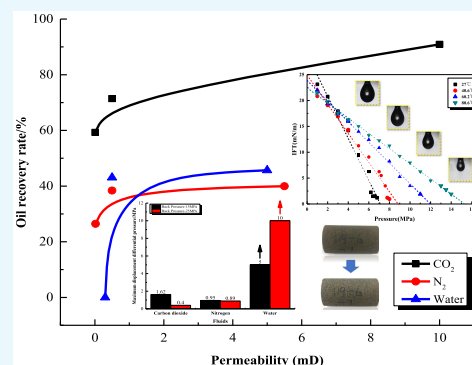
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ABSTRACT: Although flooding technology has found wide application in low-permeability reservoir development practices, the oil recovery enhancement mechanisms for different injection fluids still lack specific focus based on comprehensive investigations. Therefore, in this paper, supercritical CO₂ (ScCO₂), N₂, and water injection processes in oil-saturated low-permeability tight cores were comparatively studied. To reveal the effect of physicochemical properties of the injection fluid on the oil recovery efficiency, the Berea sandstones with three permeability levels and kerosene were employed in this study to exclude other parameter influences. The flooding processes employing various injection media were investigated based on quantitative comparisons of the oil recovery factor and the displacement pressure difference at two system pressures. The experimental results show recovery efficiencies of 59–91 and 84–92% with the increasing permeability for the ScCO₂ injection process at system pressures of 15 and 25 MPa, respectively, which are much higher than 26–40 and 21–52% in the N₂ case and 43–46 and 45–49% in the water cases. Interfacial tension (IFT) measurement results indicate that miscibility conditions have been achieved for the ScCO₂/oil system, thus leading to much higher oil recovery. On the other hand, the pressure difference results show a similar magnitude of 10 MPa/m for both ScCO₂ and N₂ processes, which is much lower than the 100 MPa/m for the water flooding cases. Comprehensive comparison shows that ScCO₂ shows great advantages in the application of unconventional reservoirs. It is expected that our research work could enrich the investigations of CO₂ flooding and the in-depth understanding of the mechanisms and better guide the utilization of CO₂.



1. INTRODUCTION

Tight reservoirs are widely distributed in the world, and they are becoming a hot area of global oil and gas exploration and development. To improve the recovery of tight reservoirs, it is necessary to dedensify the reservoir and increase the reservoir energy, to improve the mobility of fluid in tight reservoirs. There are many ways to develop tight reservoirs, such as fracturing, fluid injection, huff-and-puff processes, and so on.^{1–8} The enhanced oil recovery (EOR) in low-permeability reservoirs, especially tight reservoirs, is very different from that of conventional reservoirs because of its small pore size. At present, the use of a variety of different injection fluids has been tried, including gas flooding and liquid flooding, and the injection methods include continuous injection and huff and puff.^{9–14} Among them, the gas used in gas flooding mainly includes CO₂, N₂/air,^{15,16} natural gas, and so on, and the liquid flooding based on water includes brine, surfactant solution, nanofluid, and so on. There are also differences in the mechanism of gas flooding¹⁷ and liquid flooding and between different gases. A large number of experiments and simulations have been carried out to study these problems. The experimental means include displacement experiments, nuclear magnetic resonance (NMR),^{18–20} CT scan,²¹ microexperiments, contact

angle tests, and so on; the simulation includes the use of CMG, ECLIPSE, UT-COMP, and other software; some models established by themselves.

Gas flooding is the most widely used method because of its good injectivity, which is very important for tight reservoirs. As the most potential oil displacement agent for tight reservoirs, CO₂ has a lot of research results. Macroscopically, core experiments show that CO₂-enhanced oil recovery is good. In terms of the EOR mechanism, CO₂ is mainly reflected in several aspects: miscibility effect,²² swelling of crude oil, viscosity reduction, and improvement of the mobility ratio and reduction of interfacial tension.²³ Miscibility is an important mechanism of CO₂-enhanced oil recovery. After CO₂ is injected into the formation, dynamic miscibility is formed through multiple contacts with crude oil components, that is, multistage contact

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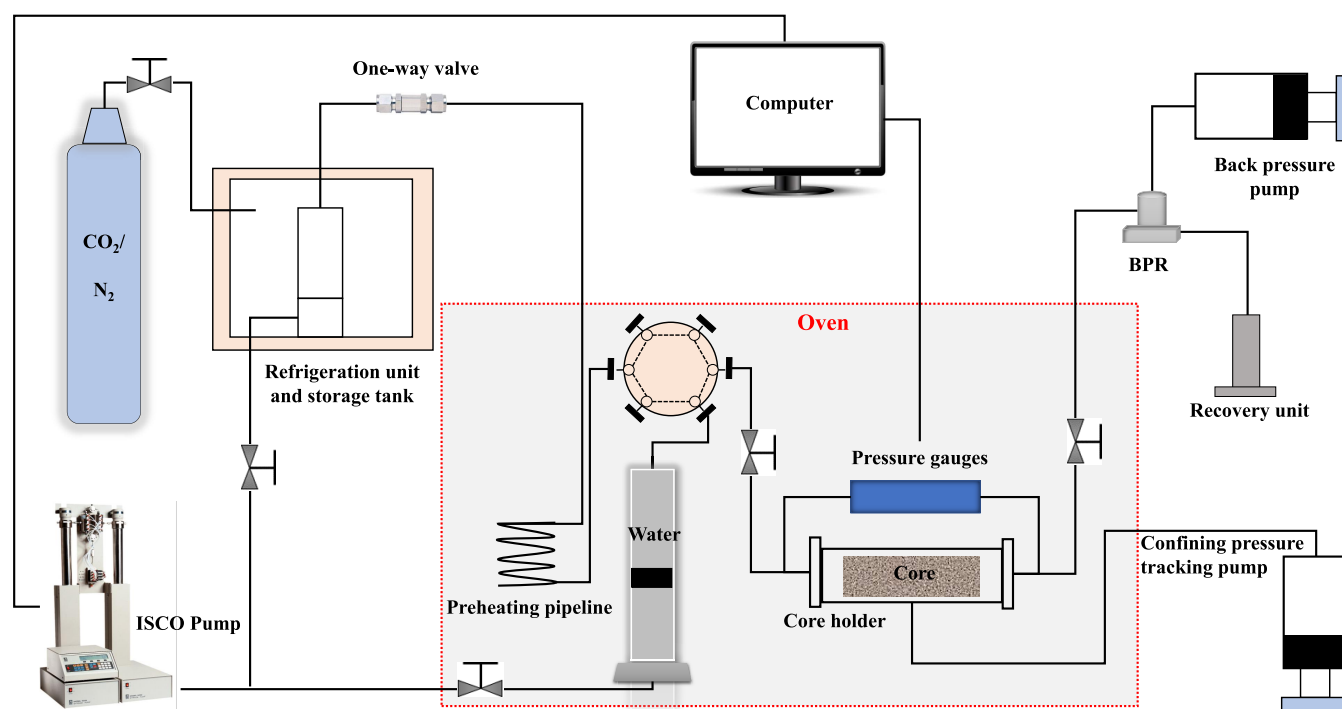


Figure 1. Schematic diagram of the experimental apparatus.

miscibility. The miscibility process of CO₂ and crude oil is a process in which CO₂ continuously extracts the components of crude oil from light to heavy, and CO₂ continuously dissolves in crude oil.²⁴ At reservoir temperature, the minimum miscible pressure (MMP) of CO₂ and crude oil is key to determine the miscible flooding effect.^{25–27} In addition, in tight reservoirs, matrix is the main reservoir space of crude oil. However, due to low permeability and small pore diameter of the matrix, an effective displacement system cannot be established in the reservoirs. Therefore, many scholars believe that diffusion of CO₂ plays a key role in tight reservoirs.^{28–32} At the microlevel, mainly focusing on the production of oil in pores of different sizes and the change of the pore structure, these results show that the oil with relatively small pores is preferentially displaced in the imbibition process, while the oil with relatively large pores is mainly displaced in the CO₂ huff-and-puff process.³³ The NMR T₂ spectra provide conclusive evidence that the chemical reactions mainly occur in large pores of tight rock during either flooding or huff-and-puff processes.³⁴ The basic mechanism of oil migration during huff and puff is gas exsolution and expansion, including bubble nucleation, growth, coalescence, and elongation along the fracture.³⁵ As a relatively cheap and easily prepared gas, N₂ is also widely studied. The nitrogen flooding mechanism mainly includes maintaining and increasing reservoir pressure; reducing interfacial tension and capillary force to improve oil displacement efficiency; and gravity differentiation and changing the displacement direction to improve sweep efficiency.^{36,37} In addition, according to the mixing ratio of nitrogen, N₂ flooding can be extended to air flooding and oxygen, reducing air flooding, including some special mechanisms. In low- and ultralow-permeability reservoirs, air is easier to inject than water, and there is no influence of water sensitivity, so it is an effective medium for reservoir energy supplement. N₂ flooding is applied in the later stage of high water cut; because of the difference of density, nitrogen injection can improve the vertical sweep coefficient and produce “attic

oil”. The difference between nitrogen and CO₂ is that nitrogen plays an important role in the production of crude oil in small pores.³⁸ NMR experimental results well illustrate this point; after CO₂ flooding, the NMR T₂ signal mainly decreased in the large pores, while during N₂ flooding, signals mainly changed both in small pores and large pores. The EOR mechanism of natural gas is similar to that of CO₂. Generally, natural gas, especially natural gas mixtures, has a better oil displacement effect than CO₂, but due to the limitation of safety and gas sources, it is much less than that of nitrogen dioxide in research and field use. Under a low gas–oil ratio, oil swelling plays an important role, and under a high gas–oil ratio, vaporization is more important.

Water is the most convenient to use in oil displacement, but for low permeability, especially tight reservoirs, injectability is the key problem to be solved in water displacement. Water injection development mainly includes imbibition water injection and huff-and-puff water injection. Imbibition water injection refers to the method of water injection and oil displacement through fractures in low-permeability fractured reservoirs. Imbibition water injection refers to the method of water injection and oil displacement through fractures in low-permeability fractured reservoirs. Chen³⁹ studied the water injection displacement process of tight reservoirs through numerical simulation, which shows that the recovery rate of water flooding is lower than that of gas flooding. For those reservoirs with undeveloped natural fractures, the injectability is relatively poor, and it is very difficult to use imbibition water injection. Some scholars use huff-and-puff water injection to supplement formation energy. Zhao⁴⁰ determined the basic principles and parameters of a reasonable injection production huff-and-puff system based on determining the basic laws and according to the evaluation results of the horizontal well development test. However, imbibition water injection is prone to gas channeling, forming an invalid water injection circulation channel, and the swept area of huff-and-puff water injection is

also limited, and gas flooding is still the main way. In addition, some studies have improved the injectability and recovery effect of water flooding by adding surfactants and nanoparticles so as to expand the application range of water flooding.

In summary, the three most valuable and representative injection fluids are CO₂, N₂, and water. Although there are some review studies,^{41–43} there is a lack of systematic experimental studies, especially on the core permeability effect and system pressure effect and the comparison with the water injection method. At the same time, there is a lack of reservoir pertinence in the CO₂ EOR mechanism and N₂ EOR mechanism. Therefore, the comprehensive evaluation of the applicability of the flooding methods in different reservoirs has important guiding significance for the development of tight reservoirs. Taking three types of cores with different permeabilities and different back pressures in account, we carried out CO₂, N₂, and water displacement research and compared and analyzed the oil displacement mechanism and effect. At last, the applicability evaluation in different permeable cores is given. The results are expected to have a new reference value and guiding significance.

2. EXPERIMENTAL SECTION

2.1. Apparatus. In this experiment, a TC-II high-temperature and high-pressure multifunction core displacement experimental device was used to carry out core displacement research. The temperature range of the core holder is from room temperature to ~150 °C, and the pressure range is 0–70 MPa. The experimental device is mainly composed of the drive system, gas injection system, temperature control system, metering system, data acquisition system, displacement system, and auxiliary system. The schematic diagram of the experimental device is as follows (Figure 1).

It is mainly composed of the ISCO pump, automated confining pressure-tracking pump, intermediate container, core holder, back pressure control system, carbon dioxide condenser, etc.; the automated confining pressure-tracking pump ensures the stability of model back pressure and circumferential pressure. The pressure range is 0–70 MPa, and the control accuracy of pressure stabilization is ±0.2 MPa.

The carbon dioxide condensation injection system is mainly composed of a refrigeration unit and carbon dioxide storage tank, which are used to cool and liquefy carbon dioxide gas. The gaseous carbon dioxide is cooled to the liquid state, and the liquid carbon dioxide is stored in the high-pressure storage tank in the low-temperature bath (N₂ can also be stored in this tank before injection). The liquid carbon dioxide is pressed into the piston container using gas pressure, and the constant-speed constant-pressure pump is used for quantitative or constant-pressure injection. The minimum working temperature of the low-temperature bath is –5 °C, and there is an external pipeline to cool the piston container. The volume of the high-pressure storage tank is about 1000 mL, and the pressure is 70 MPa.

2.1.1. Temperature Control System. The temperature control of the intermediate container and the holder is mainly realized through the incubator. The front part of the incubator is equipped with a rotating opposite door with an observation window. Above the opposite door are the high-precision temperature controller, power switch, heating, fan switch, etc.; there are small ray lamps in the incubator to improve the brightness of the incubator and facilitate observation. There are diversion grooves at the bottom of the incubator to facilitate cleaning.

2.1.2. Auxiliary System. The auxiliary system is mainly composed of the safety valve and various pipe valves. When the system is overpressured, the overflow hole of the safety valve will open to discharge the excess gas or liquid in the system, to reduce the internal pressure of the system and protect the personal safety of equipment and operators. The pipe and valve parts of the system are mainly made of 316 stainless steels. The sealing of all kinds of pipe and valve parts is made using the PTFE sealing material, which can withstand the working conditions of high temperature and high pressure.

2.2. Materials. **2.2.1. Core.** The Berea core was used in the experiment (Figure 2). The permeability is generally divided



Figure 2. Image of the Berea core sample.

into three levels of 0.1, 1, and 10 mD, with a total of 18 groups of cores. The physical parameters and composition of the core are shown in Tables 1 and 2.

Table 1. Physical Parameters of the Core

core nos.	diameter (mm)	length (mm)	porosity (%)	permeability (10 ⁻³ μm ²) (gas)
1#	25.16	49.00	7.07	0.01
2#	25.16	49.08	15.51	0.5
3#	25.30	49.52	15.80	10
4#	25.20	47.76	10.03	0.02
5#	25.10	51.00	11.18	0.5
6#	25.20	48.38	22.10	5.5
7#	25.20	47.76	7.77	0.3
8#	25.20	49.58	13.86	0.5
9#	25.24	49.12	18.63	5
10#	25.10	50.10	4.94	0.15
11#	25.18	49.20	14.24	0.5
12#	25.20	47.96	19.19	5.5
13#	25.18	51.46	8.00	0.015
14#	25.10	46.98	14.24	0.5
15#	25.08	48.60	16.30	5.3
16#	25.20	47.76	7.77	0.3
17#	25.16	50.36	13.68	0.5
18#	25.24	49.40	19.28	5.0

2.2.2. Gas. Industrial-grade nitrogen gas with a purity of 99.99% and high-purity CO₂ with a purity of 99.8% were used in the experiments.

2.2.3. Oil. Kerosene was used in the experiments. The density of kerosene is 0.80 g/cm³.

2.2.4. Water. Deionized water was used in the experiments.

2.3. Experimental Process.

- (1) First, the core is cleaned, dried, and weighed.
- (2) After the core sample is vacuumized for 4 h, kerosene is sucked into the saturated oil tank by vacuum and then pressurized for 15 MPa and saturated for 6 h.
- (3) At the end of oil saturation, the core is taken out and weighed and stored in oil.

Table 2. Composition of the Core

permeability (mD)	quartz	potash feldspar	plagioclase	calcite	dolomite	siderite	hematite	clay
0.1	61	4	12	5	8		1	9
1	50	20	23			1		6
5	83	2	1	6	7			1
10	89	3	5					3

(4) Displacement operation: The oil-saturated core sample is put into the core holder, and the pipe at the back end of the holder is filled with oil; the temperature is set at 50 °C. Pressure and velocity are set according to permeability and displacement fluid; as shown in Table 3, the backpressure is set to 15 or 25 MPa. Therefore, CO₂ is supercritical under these experimental conditions.

Table 3. Displacement Process

back pressure (MPa)	core nos.	displacement fluid	displacement velocity
15	1	CO ₂	constant pressure 20 MPa
	2	CO ₂	constant speed 0.5 mL/min
	3	CO ₂	constant speed 0.5 mL/min
	4	N ₂	constant pressure 20 MPa
	5	N ₂	constant speed 0.5 mL/min
	6	N ₂	constant speed 0.5 mL/min
	7	water	constant pressure 35 MPa
	8	water	constant pressure 25 MPa
	9	water	constant speed 0.5 mL/min
25	10	CO ₂	constant pressure 30 MPa
	11	CO ₂	constant speed 0.5 mL/min
	12	CO ₂	constant speed 0.5 mL/min
	13	N ₂	constant pressure 35 MPa
	14	N ₂	constant speed 0.5 mL/min
	15	N ₂	constant speed 0.5 mL/min
	16	water	constant pressure 35 MPa
	17	water	constant pressure 35 MPa
	18	water	constant speed 0.5 mL/min

(5) A balance and measuring cylinder are used to record the output liquid at the outlet.

(6) After displacement, the core is taken out and weighed, and the oil production and recovery are calculated (Figure 3).

3. RESULTS AND DISCUSSION

3.1. Summary of the Results. Table 4 is a summary of all experimental cores and oil recovery factors, which mainly lists the oil recovery factors of different fluids injected under different cores and backpressures and the corresponding injection pressure (pressure drop). Next, the results will be analyzed from three aspects: pressure drop, differential pressure, and oil recovery.

3.1.1. Pressure.

(1) At 15 MPa backpressure, the greater the permeability is, the smaller the pressure drop is. In the permeability level

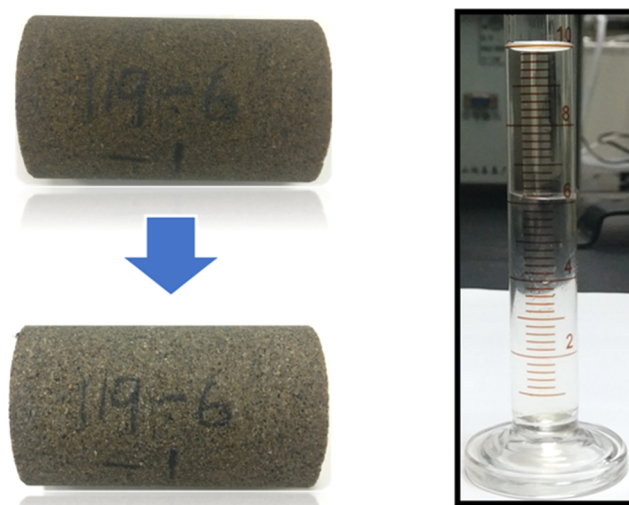


Figure 3. Core image before and after displacement and liquid production metering.

Table 4. Summary of Oil Recovery Results

back pressure (MPa)	core nos.	displacement fluid	oil recovery (%)	pressure drop (MPa/m)
15	1#	CO ₂	59.29	90.82
	2#		71.42	33.01
	3#		90.91	9.29
	4#	N ₂	26.45	112.86
	5#		38.41	18.63
	6#		39.95	8.68
	7#	water	0	∞
	8#		43.07	201.69
	9#		45.68	109.79
25	10#	CO ₂	83.67	99.80
	11#		79.21	8.13
	12#		91.55	8.97
	13#	N ₂	21.34	194.33
	14#		49.62	14.26
	15#		52.08	5.35
	16#	water	0	∞
	17#		48.91	198.57
	18#		45.17	253.44

of 0.1 mD, CO₂ and N₂ have certain injectability at constant pressure, and water cannot be injected at constant pressure. In the permeability level of 1 mD, the injectability of CO₂ and N₂ is good at constant speed, and the injection pressure drop is less than 33 MPa/m. Water can be injected at constant pressure, but its injectability is poor. In the permeability level of 10 mD, three kinds of displacement fluids have certain injectability at constant speed, CO₂ and N₂ have better injectability, and the injection pressure drop is less than 10 MPa/m. The injection pressure drop of water is about 100 MPa/m, which is about 10 times that of CO₂ and N₂.

(2) At 25 MPa back pressure, the greater the permeability is, the smaller the pressure drop is. In the permeability level of 0.1 mD, CO₂ and N₂ have certain injectability at constant pressure, but they are relatively poor, and water cannot be injected at constant pressure. In the permeability levels of 1 and 10 mD, CO₂ and N₂ have good injectability at constant speed, while CO₂ and N₂ have good injectability. With the increase of permeability, the pressure drop of CO₂ has little change, which is about 8–9 MPa/m. With the increase of permeability, the injection pressure drop of N₂ decreases significantly, and the lowest is about 5 MPa/m. In the permeability level of 1 mD, the injectability of water is poor, and constant-pressure injection is needed. In the permeability level of 10 mD, the injection pressure rises rapidly, and the pressure drop is more than 250 MPa/m. The change of

pressure with the pore volume of CO₂, N₂, and water is shown in Figures 4–6.

3.1.2. Maximum Displacement Differential Pressure. To clearly observe the injectability of the three fluids, the maximum displacement differential pressure (MDP) of the three fluids in the permeability levels of 1 and 10 mD is compared in Figures 7 and 8, respectively.

As shown in Figures 7 and 8, the maximum displacement differential pressure (MDP) of water is much larger than that of the gas phase (more than 10 times), which reflects that the injectability of gas is better than that of water. The MDP of CO₂ and N₂ is 0.26–1.62 MPa, while the MDP of water is over 5 MPa (the upward arrows in Figure 4 represents exceeding the current pressure because of the constant-pressure conditions). The MDP of the gas phase decreases with the increase of back

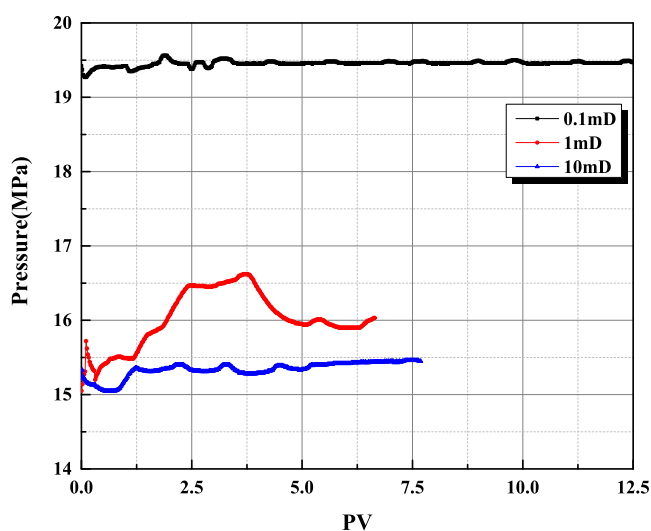


Figure 4. Change of pressure with the injection pore volume of CO₂ flooding.

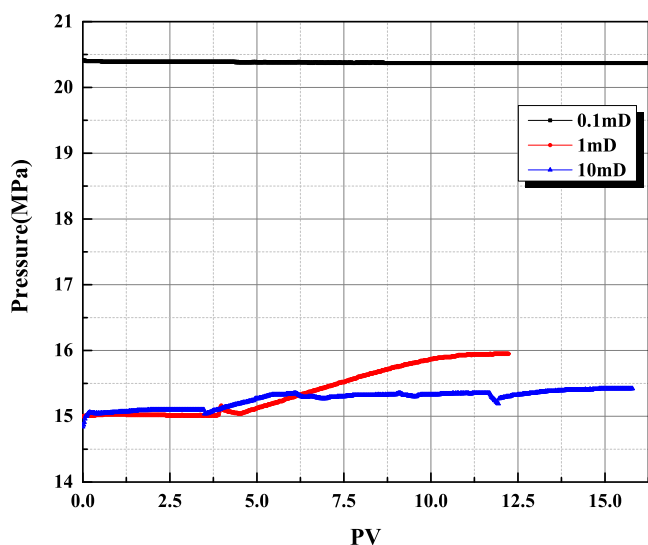


Figure 5. Change of pressure with the injection pore volume of N₂ flooding.

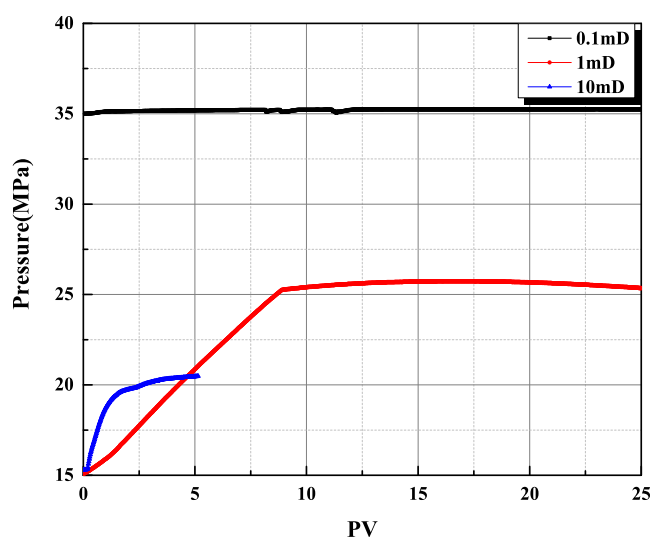


Figure 6. Change of pressure with the injection pore volume of water flooding.

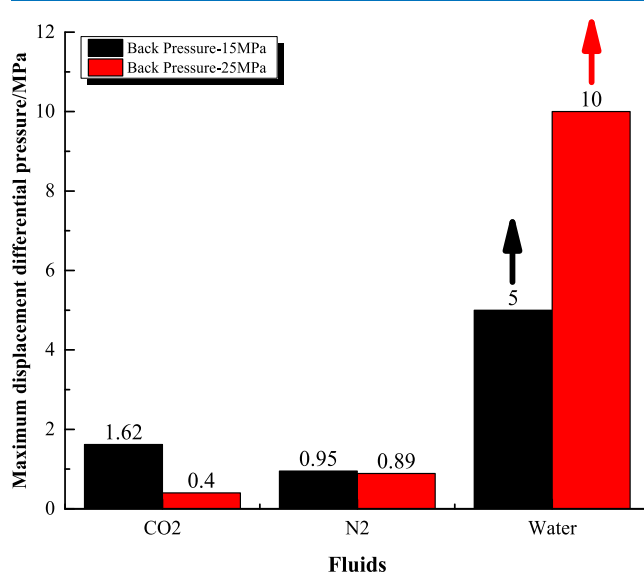


Figure 7. Comparison of maximum displacement differential pressure of three displacement fluids (1 mD level).

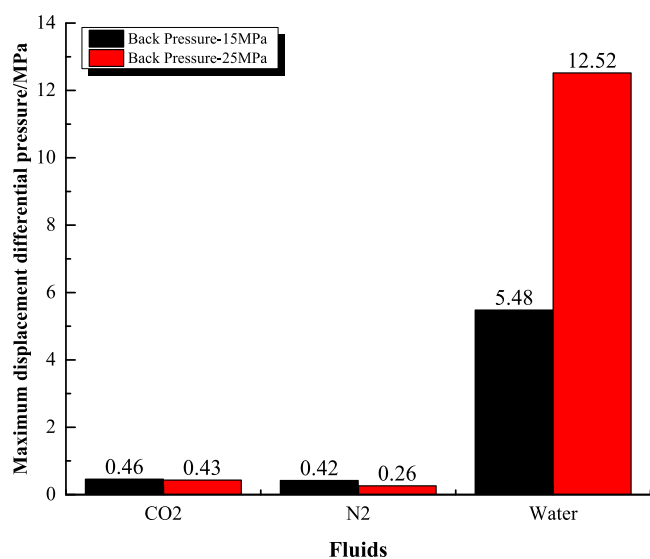


Figure 8. Comparison of maximum displacement differential pressure of three displacement fluids (10 mD level).

pressure (15–25 MPa), and MPD of water increases with the increase of back pressure.

3.1.3. Oil Recovery.

- (1) At 15 MPa, the oil recovery rate of CO₂ in three permeability levels is 59.29, 71.42, and 90.91%, respectively, and at 25 MPa, it is 83.67, 79.21, and 91.55%, respectively. Generally, with the increase of permeability, the oil recovery increases, and the oil displacement effect is very good, even the 0.01 mD core can reach about 60%, up to 90%. However, the pressure drop is as high as 90.82 MPa/m below 0.1 mD.
- (2) At 15 MPa, the oil recovery rates of N₂ in the three permeability levels are 26.45, 38.41, and 39.95%, respectively, and at 25 MPa, they are 21.34, 49.62 and 52.08% respectively. With the increase of permeability, the oil recovery increases, and the oil displacement effect is better when the permeability is above 0.1 mD, but the oil recovery is not high when the permeability is below 0.1 mD, and the pressure drop reaches 112.86 MPa/m.
- (3) Water flooding cannot produce oil in the permeability level of 0.1 mD. When the permeability is more than 0.1 mD, the oil recovery rate is 33.23–48.91%, and the oil displacement effect is good, but the injection pressure is too high with the pressure drop of more than 100 MPa/m. The change of oil recovery with the pore volume of CO₂, N₂, and water is shown in Figures 9–11.

3.2. Discussion. **3.2.1. Analysis of Influencing Factors (Permeability/Pressure).** In this part, we further analyze the recovery factor and draw the correlation curve to see the change of oil recovery factor of different displacement fluids more clearly with permeability and back pressure. In addition, the IFT of CO₂/kerosene and N₂/kerosene was tested for better analysis. Combined with the results of pressure and oil production, the influencing factors of gas and liquid flooding recovery are analyzed.

As can be seen from Figures 12 to 14, both permeability and pressure have important influence on oil recovery

- (a) Permeability: for gas flooding (CO₂, N₂), with the increase of permeability, the oil recovery shows an increasing trend, and the CO₂ increase effect is obvious,

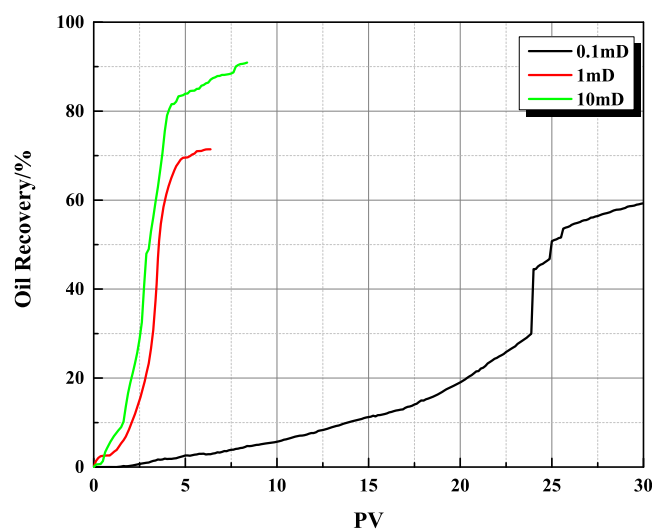


Figure 9. Change of oil recovery with the pore volume of CO₂ flooding.

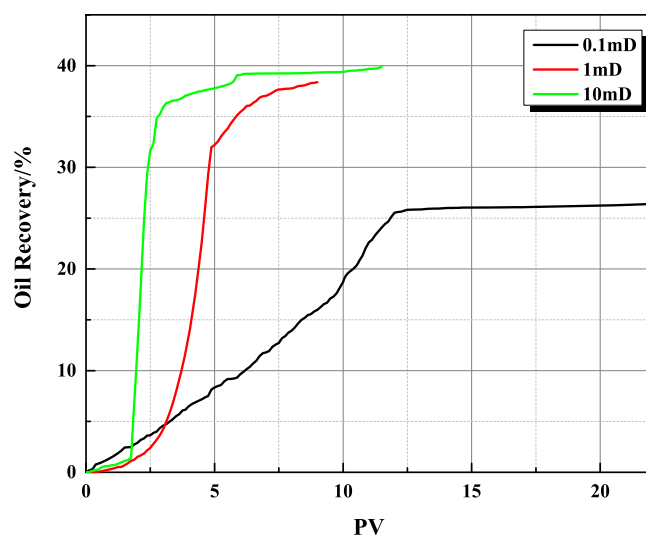


Figure 10. Change of oil recovery injection with the pore volume of N₂ flooding.

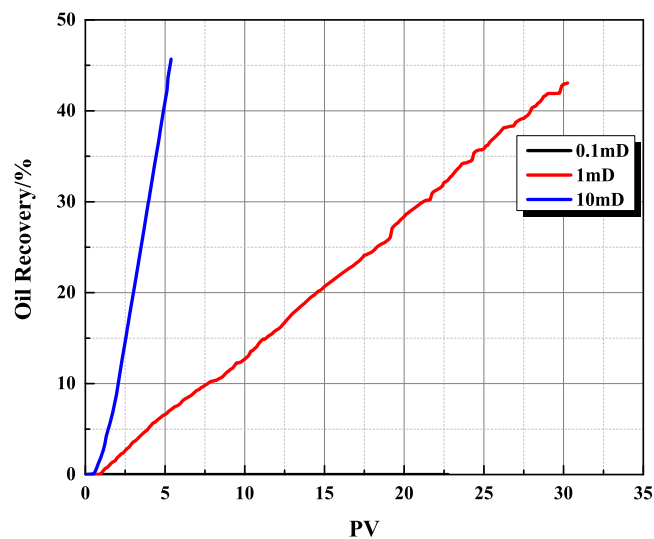


Figure 11. Change of oil recovery with the pore volume of water flooding.

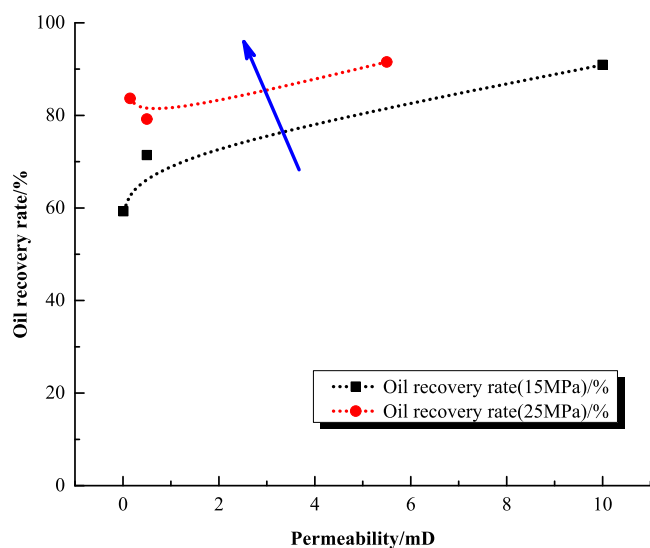


Figure 12. Oil recovery rate with different permeabilities of CO₂ flooding.

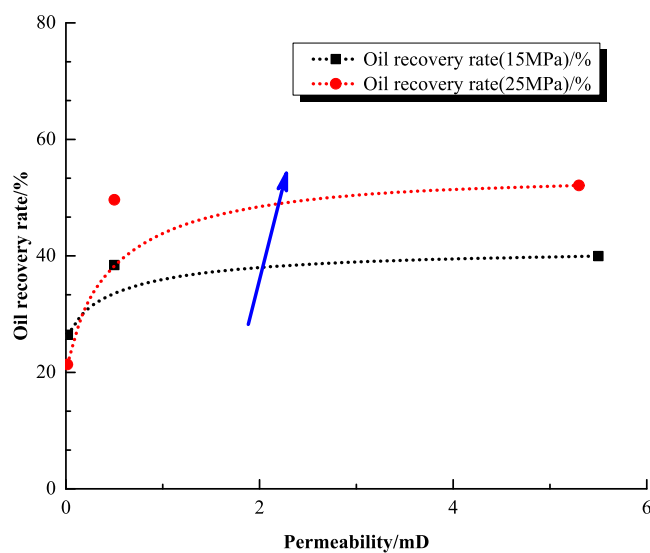


Figure 13. Oil recovery rate with different permeabilities of N₂ flooding.

up to more than 90%, mainly due to the miscibility effect of CO₂. By testing CO₂/kerosene IFT (Figure 15), we obtained the minimum miscibility pressure of kerosene at different temperatures (Table 5). The results showed that CO₂ reached miscibility under the experimental conditions (above 15 MPa, temperature 50 °C). With the increase of permeability, the miscibility degree of CO₂ in the core is higher above 1 mD, but the change trend is not obvious below 1 mD. The results of nitrogen flooding show that the recovery increases greatly with the increase of permeability below 1 mD, but the increase effect is not obvious above 1 mD. The main reasons are the increase of oil mobility with the increase of permeability and the gas channeling of N₂ with higher permeability. For liquid flooding (water), in the permeability level of 0.1 mD, the oil recovery is zero. When the permeability is above 1 mD, the oil recovery rate has little change with permeability.

- (b) Pressure: for all the displacement fluids in the experiment, the greater the back pressure, the greater the oil recovery.

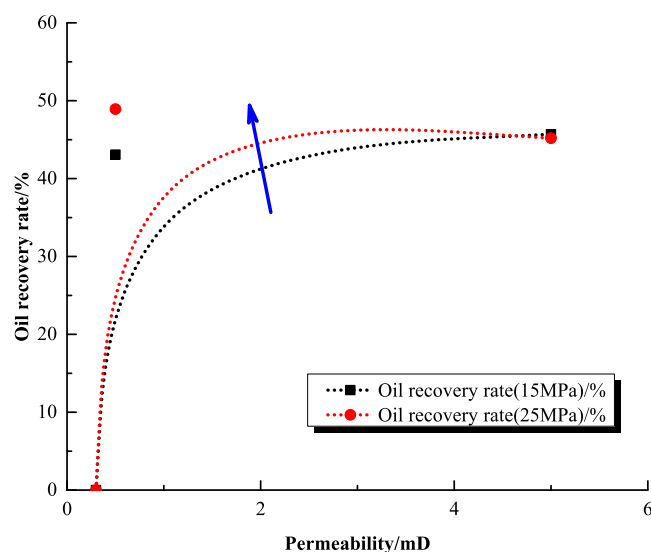


Figure 14. Oil recovery rate with different permeabilities of water flooding.

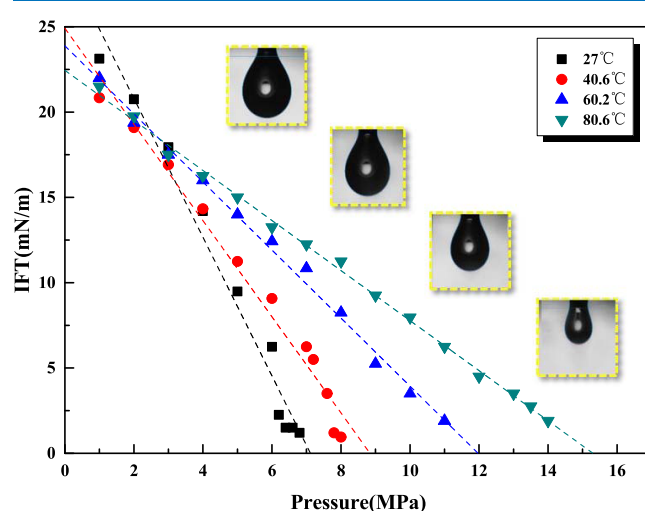


Figure 15. IFT of CO₂/kerosene.

Table 5. Minimum Miscible Pressure of CO₂/Kerosene at Different Temperatures

temperature	27 °C	40.6 °C	60.2 °C	80.6 °C
pressure	7.2 MPa	8.8 MPa	12 MPa	15.3 MPa

The increase of CO₂ recovery is mainly due to better miscibility. The increase of N₂ recovery is mainly due to the increase of N₂ viscosity and the decrease of interfacial tension between N₂ and oil as shown in Figure 16 (N₂/kerosene IFT).

3.2.2. Comparative Analysis of Different Displacement Fluids. Figures 17 and 18 compare and analyze the recovery factors of different fluids. Combined with the pressure drop results given in Table 4, the following can be seen deduced:

- (1) In any case, CO₂ flooding is the best, which is much higher than other displacement fluids.
- (2) In the permeability level of 0.1 mD, water flooding is not suitable. N₂ flooding can achieve a certain recovery effect, with a recovery rate of about 25% and pressure drop ratio of about 112 MPa/m. CO₂ flooding can achieve a

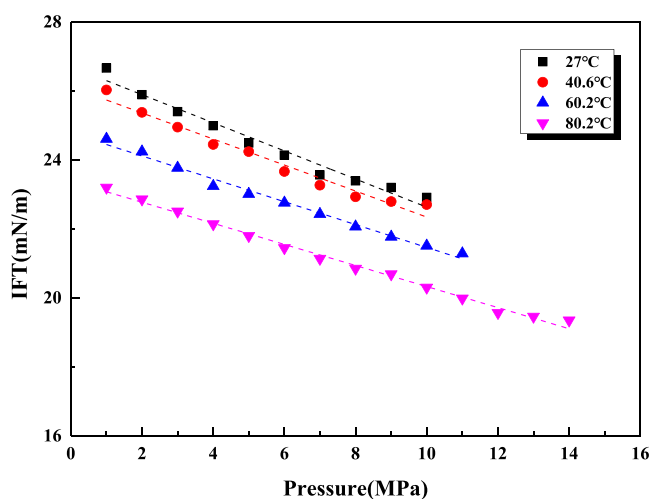


Figure 16. IFT of N₂/kerosene.

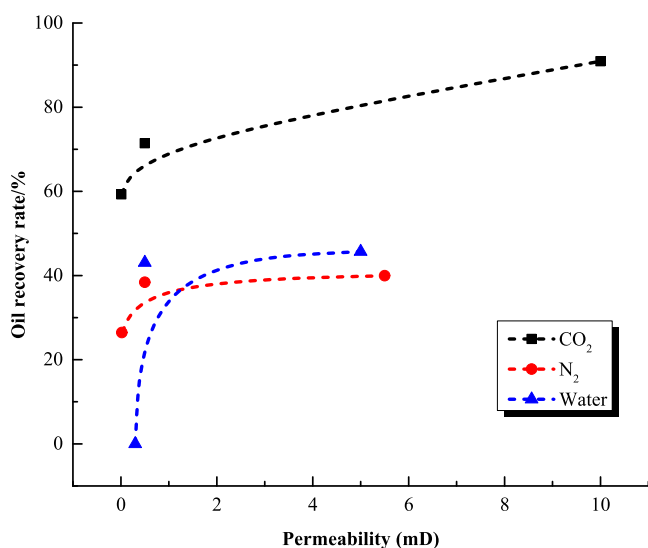


Figure 17. Oil recovery rate of different displacement fluids with permeability changing at 15 MPa backpressure.

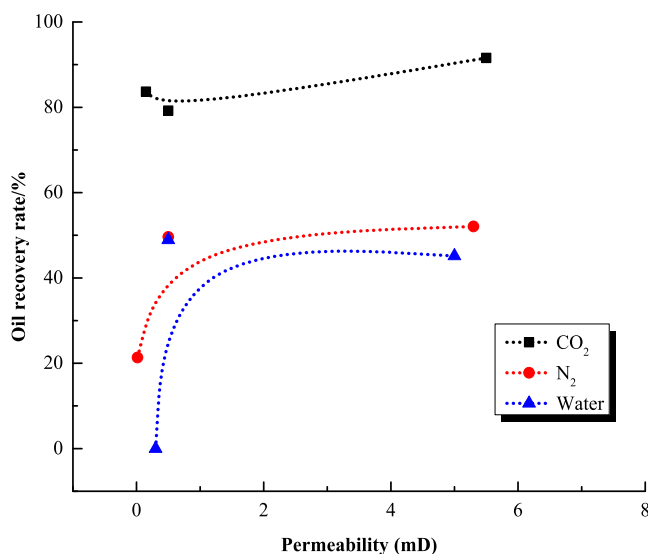


Figure 18. Oil recovery rate of different displacement fluids with permeability changing at 25 MPa backpressure.

recovery rate of about 60% and pressure drop ratio of about 91 MPa/m.

- (3) When the permeability is more than 1 mD, the CO₂ recovery rate is more than 70%, even more than 90%. The recovery rate of N₂ and water has little difference, about 40–50%. Especially at higher pressure, N₂ flooding can reach a level close to or even slightly higher than that of water (about 50%). The pressure drops of CO₂ and N₂ are relatively low, ranging from 5.35 to 33 MPa/m, while the pressure drop of water is relatively high, above 100 MPa/m. Therefore, when the formation pressure is high, N₂ may be the first choice next to CO₂.

4. CONCLUSIONS

- (1) On the general trend, the recovery efficiency of the CO₂(ScCO₂) injection process increases with the increase of core permeability and system pressure. The oil recovery rate increases from 59 to 92%. Larger pore throat sizes in the higher permeability cores and the higher miscibility content could contribute to higher recovery efficiency.
- (2) The recovery efficiency of the N₂ injection process increases with the increase of core permeability and system pressure as well. The oil recovery rate increases from 21 to 52%. The increase of N₂ efficiency recovery is due to the increase of N₂ viscosity and the decrease of interfacial tension between N₂ and oil.
- (3) ScCO₂ injection shows unanimously and remarkably higher oil recovery rate compared with the N₂ and water injection processes, indicating the advantage and the potential application of the miscible ScCO₂ injection process on tight oil reservoir development practices. However, CO₂ flooding needs to solve the problem of high displacement pressure below the 0.1 mD permeability level or further investigate the application effect of the huff-and-puff development mode. Besides, water flooding is not suitable for the formation with permeability less than 1 mD.

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Notes

The authors declare no competing financial interest.

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