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Seepage Characteristics of Fluids in Cross-Scale Unconventional Oil Reservoirs Based on Different CO_2 Miscibility Degrees

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Abstract

CO_2 flooding is becoming significant due to unconventional oil recovery enhancement and global warming gas storage. The mass transfer of the CO_2-oil system generates multiple phase zone distribution between the injection well and the production well, which significantly affects the fluid's seepage capacity. Besides, the synergistic effect of miscibility degree and pore size effect on CO_2 flooding performance is also not quantified, which is rarely reported in this field. In this work, the effects of pose scale effect and miscibility degrees on CO_2 flooding are studied by rock cores with three permeability levels under different miscibility degrees. The relative permeability curves of three miscibility degrees and a new threshold pressure gradient (TPG) considering both pressure sensitivity and oil properties are conducted, which are proposed as the indicator of the seepage capacity for the reservoir fluids. On this basis, the improvement degree of supercritical CO_2 injection on fluid flow capacity in the reservoir with cross-scale effect and the distribution characteristics of CO_2 four phase zones under formation pressure field are quantitatively evaluated. The results show that when the reservoir permeability is less than 4×10^{-3} μm^2, the seepage capacity of fluid decreases exponentially and CO_2 injection can reduce the fluid seepage resistance to one-third of the original oil phase zone of the tight reservoirs. Compared with the original oil phase zone, the seepage resistance of the frontal oil phase zone and miscible zone decreased by 23.4%~27.2% and 80.1%~87.4% based on the stronger mass transfer between CO_2 and crude oil, respectively. These results can furnish an in-depth understanding of the complicated mechanisms and phase behavior in CO_2 EOR in the ultra-low permeability oil reservoir.

Introduction

In recent years, with the decrease of medium and high permeability oil and gas resources [1-4], unconventional reservoir resources including low permeability and tight oil reservoirs have accounted for nearly 40% of the crude oil supply in the world [5-6]. However, the primary recovery of unconventional reservoirs is only 1~2%, and a large amount of crude oil is trapped in the formation [7], how to effectively develop unconventional reservoir resources has become a big problem [8-9]. Compared with conventional high permeability reservoirs, the pore connectivity of unconventional reservoirs is poor [10], and the pore diameter is about 5~100nm [11-12]. The strong pore-scale effect and stress sensitivity result in conventional water flooding can not develop a large amount of trapped crude oil, resulting in a waste of oil resources [13-15], and the suitable enhanced oil recovery (EOR) technologies for unconventional oil reservoir are urgently needed to be explored.

Supercritical CO_2 injection into the oil reservoirs has the advantages of dissolution, expansion, viscosity reduction, and mass transfer of components of crude oil [16-17], which can achieve the dual goals of EOR and greenhouse gas storage, which has benefits of economic and the environmental protection [18]. However, the improvement degree of reservoir fluid properties by supercritical CO_2 injection depends on the degree of miscibility between CO_2 and crude oil, which can be divided into miscible, near-miscible, and immiscible states [19-20]. A large number of studies have shown that the seepage resistance of miscible mixture fluids is lower than that of near-miscible and immiscible mixture fluids [21-22]. Therefore, in the actual field oil development, even if there is a sufficient CO_2 gas source near some reservoirs, CO_2 flooding is abandoned due to insufficient pressure smaller than the minimum miscible pressure (MMP) [23].

However, whether it is necessary to achieve a miscible state in the process of CO_2 flooding has been a focus of debate. In the actual CO_2 flooding process, the pressure profile between the injection well and the production well is constantly changing, and the pressure of the production well is often lower than the minimum miscible pressure (MMP) [24], resulting in the gradual reduction of the miscible zone between CO_2 and crude oil. Therefore, simply using the relationship between reservoir pressure and MMP to judge the standard of CO_2 flooding ignores the influence of formation pressure changes on the miscible degree between CO_2 and crude oil in the reservoir development process. In particular, the big pressure difference between the injection well and production wells in unconventional reservoirs is affected by the seepage capacity of formation fluid, and the pressure distribution has a great influence on the miscible degrees between CO_2 and crude oil under reservoir formation conditions. However, there is no relevant research at present, and the dynamic distribution characteristics of phase zones in the process of CO_2 flooding in unconventional reservoirs need to be solved urgently.

Relative permeability laboratory testing and threshold pressure gradient experiments are important methods to accurately characterize of seepage capacity of reservoir fluid. Arora et al. studied the seepage capacity difference of CO_2-dead crude oil systems under different miscible degrees by using medium permeability short rock cores [25]. Marine studies have shown that carbonized water injection in low permeability reservoirs can enhance the recovery efficacy of high-waxy crude oil in tight oil reservoirs, but the influence of pressure-sensitive effects on tight reservoirs is ignored [26]. When the tight core was saturated with dead oil, Li et al. conducted CO_2 flooding experiments and concluded that the lower the CO_2 injection rate was, the higher the recovery rate was. Wei et al also used dead oil to study the effect of CO_2 injection on the development of tight reservoirs [27]. However, the above studies all ignore the complex component exchange between CO_2 and live crude oil (saturated with dissolved gas), which seriously deviates from the real situation of reservoir fluid. The miscible process of CO_2 and crude oil requires sufficient contact time and distance [28-29], and it is difficult for short or even long cores to meet the miscibility requirements. In addition, the current research is generally limited to a single reservoir formation type, and the impact of the pore-scale effect caused by the different permeability levels on reservoir fluid seepage capacity is rarely reported.

Based on the distribution of the formation pressure field and the different miscibility between supercritical CO_2 and crude oil, the CO_2-crude oil mixture is divided into four main phase zones located in the area between the injection well and production well. On this basis, considering the pressure-sensitive effect, the threshold pressure gradient and relative permeability curve tests based on the live oil are conducted for the first time under different pore-scale cores. Besides, the compound influence of pore scale and multi-phase factors on the reservoir fluid seepage capacity is also quantitatively evaluated, expectations are put forward that the results can furnish an in-depth understanding of the CO_2 flooding and the nature of complicated seepage mechanisms in unconventional reservoirs.

Experimental section

- Materials

The dead crude oil was obtained from X oil reservoir and the physical parameters of crude oil under four phase zone conditions were listed in Table 1.

Table 1 The data of crude oil in different phase zones

Sample Number	Experimental Sample	Temperature /°C	Pressure / MPa	CO_2-live oil ratio (m^3/m^3)
1	original oil phase zone	86.4	40	0
2	frontal oil phase zone	86.4	40	20
3	miscible zone	86.4	40	120
4	residual oil phase zone	86.4	40	180

The three rock cores were taken from the X oil reservoir, the specific parameters were given in Table 2. Before experiments, the rock cores were cleaned with toluene first and then dried in a vacuum oven at the temperature of 200°C to eliminate the moisture. Besides, the gas of CO_2 conducted in experiments was sourced from a CO_2 cylinder with purity of 99.99%.

Table 2 The data of experimental rock cores

Core Number	Diameter /cm	Length /cm	Permeability /$10^{-3}\mu m^2$	Reservoir type
1	2.50	6.37	14.03	low permeability reservoir
2	2.50	6.15	1.89	ultra-low permeability reservoir
3	2.50	6.03	0.32	tight reservoir

As simulated formation oil, recombined live oil was employed to investigate the interactions between crude oil and supercritical CO_2, and it was also used in CO_2 injection experiments. Firstly, recombined live oil was prepared by stirring degassed oil and reservoir gas in a live oil generator until reservoir gas was completely dissolved in degassed crude oil under reservoir conditions (40 MPa and 86.4°C), the specific parameters of reservoir condition tested by the pressure-volume-temperature instrument were given in Table 3.

Table 3 Specific parameters of crude oil under reservoir condition

Content	Original formation pressure/MPa	Bubble point pressure/MPa	Gas-dead oil ratio m^3/m^3	Temperature/°C
parameters	40	14.2	41.4	86.4

- Experiments

(1) Seepage capacity of fluid in different permeability reservoirs

TPG is an important mechanism for fluid flow, especially for tight reservoirs, which would explain the phenomenon that pressure derivative curves exhibit a straight line of slope that is larger than zero after radial flow.

In this study, a modified TPG test of the above fluids is conducted under 86.4℃, referring to the steps as follows:

1. The core and tubing system were vacuumed for 24 hours to ensure no air remained inside the system.

2. A confining pressure of 40 MPa was applied before brine injection (0.05 mL/min), then increase the back pressure to target pressure. In other research, formation fluid was replaced by dead oil or kerosene, which can't represent realistic crude oil in the reservoir. In this work, live oil with dissolved gas was prepared, which was very close to realistic formation fluids. It should be noted that the new back pressure control system (Tuochuang Co., Ltd.,) can prevent the big fluctuation of the downstream pressure due to the oil degassing at the outlet.

3. Switch to live oil flooding to obtain original oil saturation at 43 MPa of back pressure.

4. Increase the injection pressure to 40MPa and keep it for 2 hours, measure the flow rate of the outlet, and increase to a higher pressure after the relative errors of three times testing are within 5%.

5. Repeat the testing under 12~15 different pressures until the linear section of the curve is obtained.

(2) The relative permeability of fluids in multiple phase zones

Relative permeability is not only the basis for studying the two-phase flow characteristics, but also one of the indispensable parameters for the production dynamic analysis.

The experiments were performed as follows:

1. The core and tubing system were vacuumed for 24 hours to ensure no air remained inside the system.

2. In this work, the natural long cores with a length of 80 cm and a 2528 cm slim tube were selected to simulate different phase conditions. Besides, the dead oil and live oil were used with cores and slim tubes to distinguish immiscible, near immiscible and miscible flooding, as illustrated in Figure 1.

3. Heat the thermostatic oven to objective conditions of different flooding types.

4. Saturate the core or slim tube with various kinds of oil, and measure the oil-phase permeability.

5. Inject CO_2 at a set constant rate of 0.2 cc/min; record the injection volume, pressure, and instantaneous oil and gas production data dynamically.

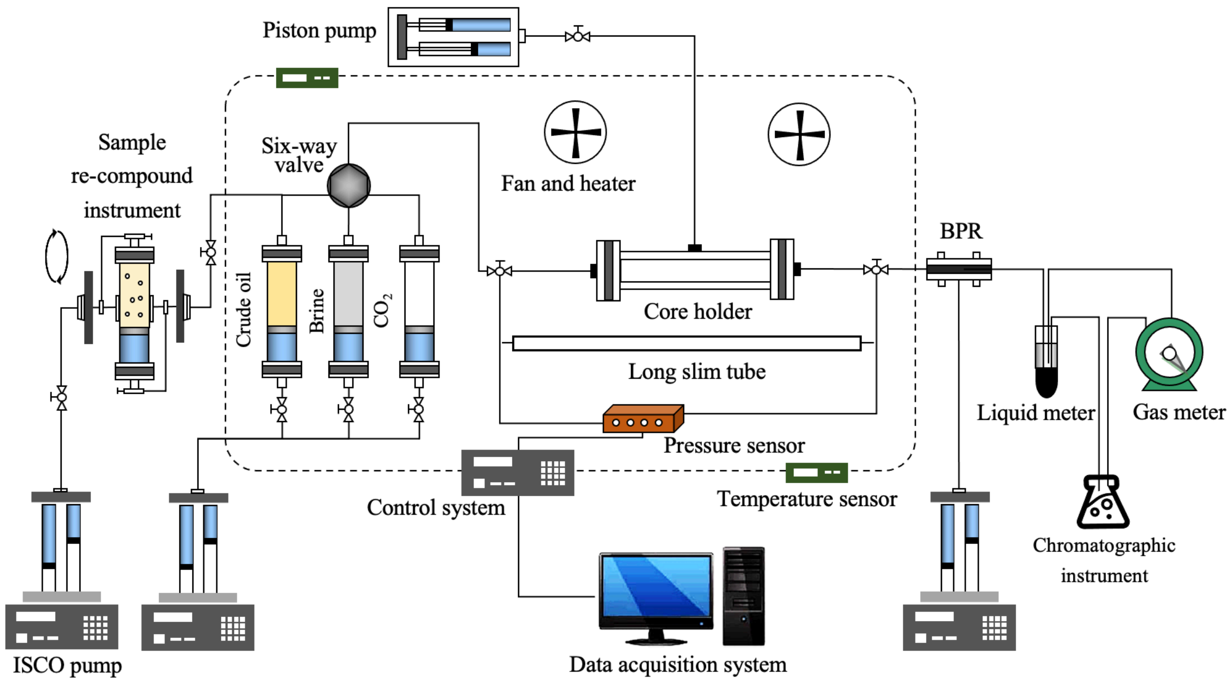

Figure 1. The schematic diagram of the relative permeability laboratory

Results and Discussion

- The relative permeability characteristics of fluids under different miscibility degrees conditions

(1) The differences between immiscible and near miscible flooding in long cores

In order to study the differences in seepage characteristics of immiscible and near-miscible CO_2 flooding, the natural cores with a length of 80 cm were selected. In this work, dead oil was used in immiscible CO_2 flooding with a result that there was no component mass transfer, and live oil was used in miscible CO_2 flooding. The results of CO_2 and oil relative permeability curves were obtained by matching production data as shown in Figure 2.

It can be seen that the two-phase zone of near miscible flooding was wider than that of immiscible flooding, with lower residual oil saturation. Besides, the gas relative permeability of near miscible flooding was higher than that of immiscible flooding, which meant stronger seepage capacity. It can be speculated that the obvious viscosity differences between dead oil and CO_2 reduced the components mass transfer of the CO_2-oil system, resulting in a strong cross-flow effect. In addition, the CO_2 relative permeability endpoint of near-miscible flooding was 0.209, while this value was 0.180 in immiscible flooding. It can be inferred, compared with miscible flooding, that strong dissolution, diffusion and mass transfer effects between CO_2 and crude oil have happened in the near-miscible flooding process[29-31].

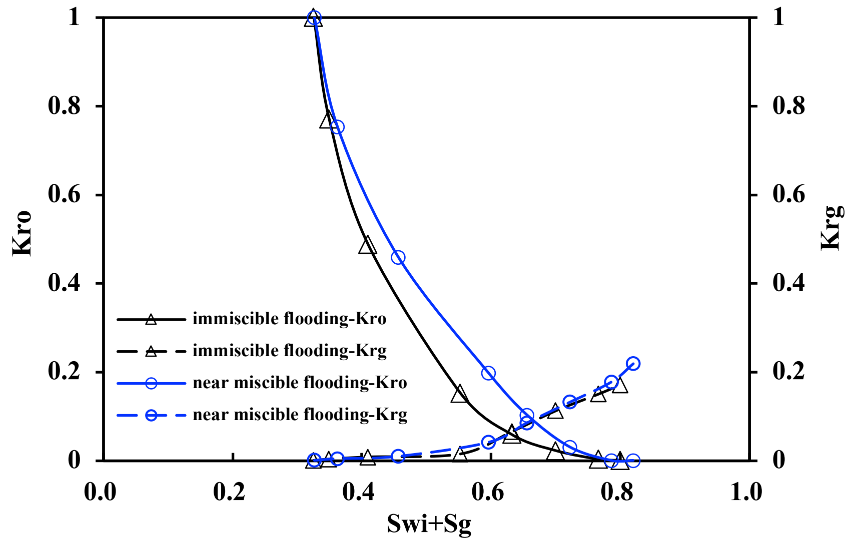

Figure 2. Relative permeability curves of immiscible and near-miscible flooding

(2) The differences between miscible and near miscible flooding in long slim tubes

The mass transfer between the CO_2 and the oil may generate a miscible or near miscible zone under the reservoir but contact time and distance of CO_2 and oil were required to achieve miscibility even if the pressure was more than MMP. In this work, to obtain miscible flooding, a 2528 cm slim tube was selected to ensure adequate contact time and distance of CO_2 and oil. As a contrast, the slim tube with 80 cm was chosen to conduct near miscible flooding. Besides, to achieve the miscible and near miscible flooding, live oil was selected. It can be seen that CO_2 flooding in the short slim tube was not under miscible flooding but near miscible flooding although the pressure was higher than MMP.

The relative permeability curves of miscible and near-miscible flooding were shown in Figure 3. With CO_2 injected into pores, CO_2 contacted and dissolved into the oil while extracting light hydrocarbons into CO_2, and CO_2 got enriched in this way. The enriched CO_2 gathered at the leading edge of displacement, however, due to the insufficient length of contact distance, CO_2 breakthroughs early from the production well and generates a communication path before it is enriched enough to achieve fully miscible flooding. Inadequate time for extracting and vaporizing light and medium hydrocarbons caused a low rate of mass transfer. Consequently, oil recovery, endpoints, and oil-phase relative permeability were affected. As shown in Figure 3, it needs to be emphasized that gas relative permeability under residual oil decreased obviously with a result that sweep efficiency was increased. Compared with miscible flooding, the range of the two-phase zone was slightly decreased by 16.3%, and residual oil saturation was increased by 15.7%. Therefore, near-miscible flooding is a good choice compared with the high equipment cost required to achieve miscible flooding if the pressure of the reservoir is less than MMP [32].

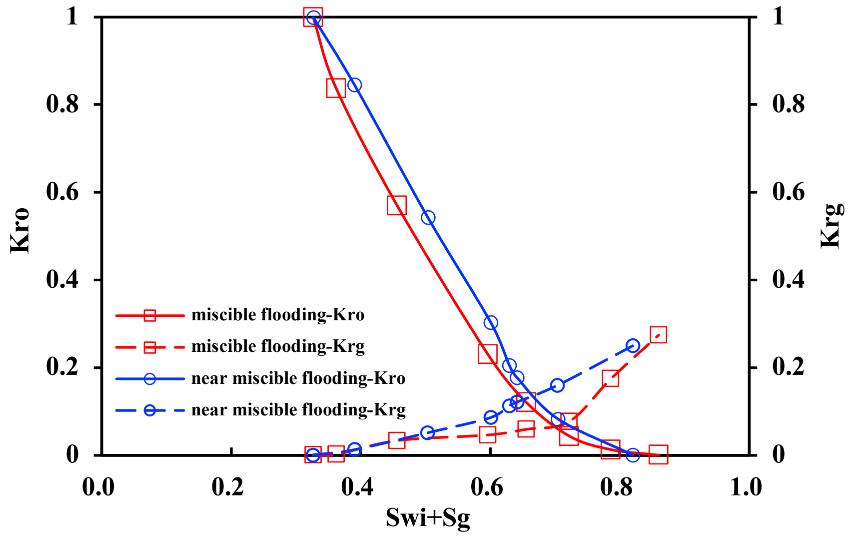

Figure 3. Relative permeability curves of miscible and near-miscible flooding

- Characteristics of phase zone distribution in the CO_2 flooding process

In the process of supercritical CO_2 flooding, the contact interface between CO_2 and crude oil gradually increases and moves forward due to the dynamic processes of CO_2 dissolution, viscosity reduction, expansion, and extraction. When the reservoir pressure is higher than MMP and the contact strength is sufficient, the interface between crude oil and CO_2 completely disappears. However, when the injection pressure is lower than MMP or the contact strength is not good, the CO_2-crude oil system is in a near-miscible or immiscible state.

Based on the characteristics of pressure distribution between injection-production Wells in unconventional reservoirs and the actual migration of supercritical CO_2 front, the CO_2 flooding process can be divided into four different phases. In the original oil zone, the seepage capacity is mainly controlled by the pore scale effect, and crude oil production depends on the CO_2 "piston" displacement mechanism. With the further migration of CO_2, a small amount of CO_2 is dissolved into the crude oil in the displacement front zone, and the viscosity of the crude oil decreases. Under proper reservoir conditions, a CO_2-crude oil system can achieve a near-miscible or miscible state at the contact interface after several contact processes. In the remaining oil zone, CO_2 diffusion and extraction are the main mechanisms of oil displacement. The existence of four phases and the proportion of different phases are closely related to the degree of miscibility. It can be seen that the distribution range of the four-phase zones depends on the reservoir and the supercritical CO_2 injection pressure as shown in Figure 4.

Therefore, the flow characteristics of reservoir fluid from the injection well to the production well vary with the distribution characteristics of the four phase zones, and the flow capacity of reservoir fluid is a comprehensive reflection of the flow capacity of the four phase zones. As far as we know, there is no study on the effect of supercritical CO_2 injection on the dynamic change of seepage capacity in different regions. In addition, the interaction strength of the CO_2-crude oil system is critical to the formation of these four zones. In other words, supercritical CO_2 injection is a multi-contact displacement process, and dynamic miscibility requires sufficient contact time and contact distance.

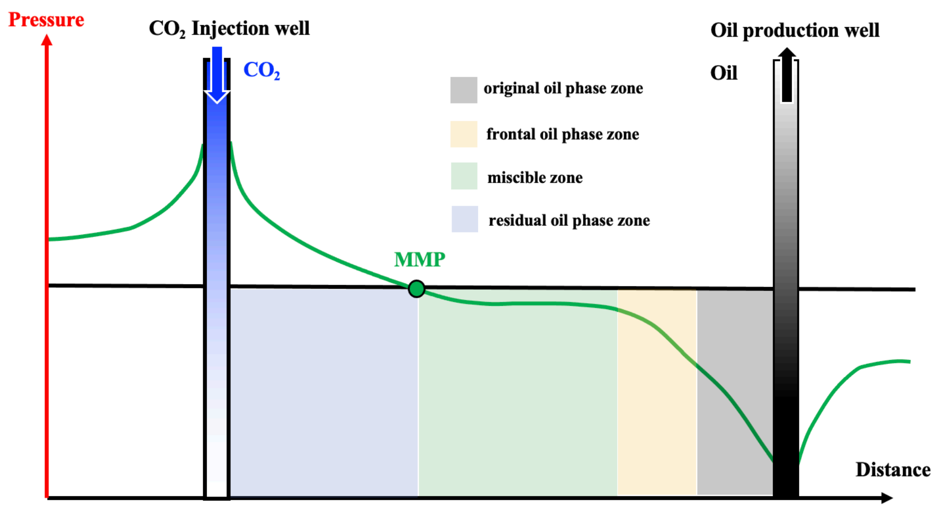

Figure 4. Distribution characteristics of reservoir pressure and four-phase zone in supercritical CO_2 flooding

- The effect of pore-scale on the seepage capacity of fluid in unconventional reservoirs

Typically, TPG is used to represent the seepage resistance. It should be noted that in the process of unconventional reservoir exploitation, the decrease of reservoir pressure increases the effective stress of the rock, leading to the decrease of reservoir permeability. Therefore, the effect of pressure sensitivity cannot be ignored. In this work, the calculation method of TPG was modified, which was close to realistic reservoir conditions.

For the original oil phase zone, the relationship between TPG and permeability is shown in Figure 5. It can be described as follows:

$$\lambda = 0.2942k^{-0.504} \tag{1}$$

Considering the pressure sensitivity of permeability, the expression of permeability is

$$K_p = K_o e^{-M(p_i - p)} \tag{2}$$

Then, the equation of modified TPG by pressure sensitivity is as follows, as shown in Figure 6. The relationship between modified TGP and the flow rate of the original oil phase zone:

$$\lambda_p = aK_o^{-b} e^{-M(p_i - p)} \tag{3}$$

Where k is permeability, $10^{-3}\mu m^2$; λ is TGP, MPa/m; K_o is original permeability, $10^{-3}\mu m^2$; M is pressure sensitivity coefficient, 1/MPa; P_i is confining pressure, MPa; P is injection pressure, MPa; K_p is permeability taking pressure sensitivity effect into consideration, $10^{-3}\mu m^2$; λ_p is modified TGP taking pressure sensitivity effect into consideration, $10^{-3}\mu m^2$; a and b is positive number depending on relationship between modified TGP and pressure.

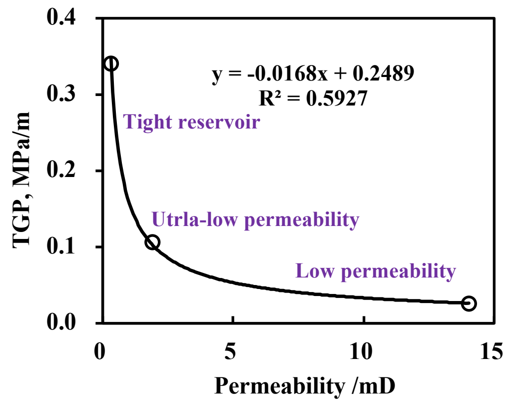

Figure 5. The relationship between TGP and the flow rate of the original oil phase zone in different cores

Due to the complexity of the microscopic pore-throat characteristics, there is an obvious nonlinear seepage stage in the low permeability and tight reservoirs. As shown in Figure 6, the curves of modified TGP and the flow rate of three different cores with original oil phases all can be divided into nonlinear stages and linear stages. For a low permeability reservoir, the curve presented a nonlinear rule until the flow rate reached 0.012 ml/min, and the corresponding modified TPG is 0.151MPa/m. With the decrease of permeability and porosity, TPG increases along with a smaller porosity, thinner throat, and worse connectivity of pore and throat. For tight reservoirs, the TPG increases to 0.418MPa/m, which means a sharp reduction of the seepage capacity. The relationship between permeability and TPG follows a power function. When the permeability is lower than 4×10^{-3}μm, TPG increases dramatically. Thus, for tight oil reservoirs, the seepage resistance is so significant so that it cannot be ignored.

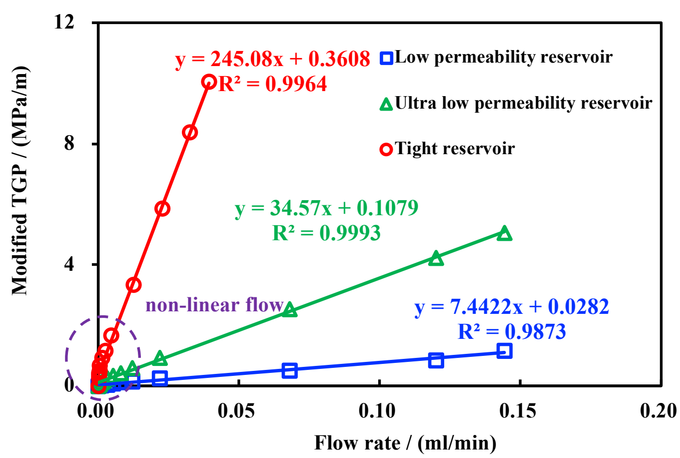

Figure 6. The relationship between modified TGP and the flow rate of the original oil phase zone

(1) The effect of miscible degree on seepage capacity of fluid in cross-scale oil reservoir

To increase the seepage capacity of fluids in low permeability and tight reservoirs, CO_2 injection can be implemented. In this work, the oil is saturated with different amounts of CO_2 to represent the property improvement under different miscible types. As the exposure time increases, a certain amount of CO_2 can be dissolved in the oil near the gas-oil contact, as can be seen from the displacement front zone as shown in Figure 7. The seepage resistance greatly reduces due to the improvement of oil properties. Both the oil density and viscosity decrease can enhance the seepage capacity. It can also be regarded as immiscible flooding conditions, which have certain but very limited effects. However, if the reservoir pressure falls in the near-miscible region or over MMP, like the targeted reservoir, a near-miscible/miscible phase zone can be formed. TPGs sharply decrease with a large amount of CO_2 dissolution in the oil, which greatly enhances the seepage capacity.

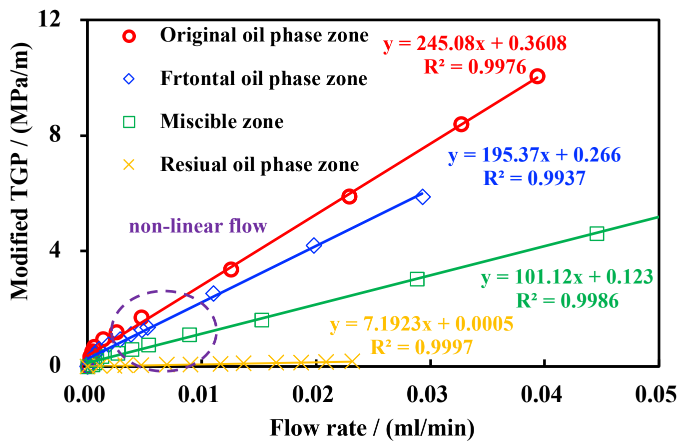

Figure 7. The relationship between modified TGP and flow rate of different displacement types

There was a trend in four phase zones that the effect of pore size became more and more significant as permeability decreased as shown in Figure 8. In addition, four displacing phase zones showed similar trends of relationship between modified TGP and permeability. Most of the coefficients (R^2) under different conversion rates were greater than 0.982, which indicated that the relationship between permeability and modified TPG was obtained with high accuracy. Also, it can be observed that the modified TGP of the near-miscible zone is only one-third of that of the original oil phase zone.

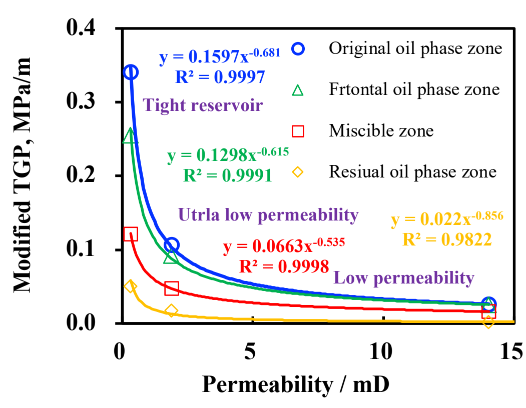

Figure 8. Modified TPG of different phase zones

The reasons behind this phenomenon were that the content of CO_2 was different in four displacement zones, and strong multi-contact and mass transfer between the CO_2 and oil were dynamic processes, which can directly affect the physical properties of the oil. As the ratio of gas to oil increases, the viscosity of the oil and CO_2 system decreases significantly, and the density declines slightly, resulting in stronger seepage capacity. Therefore, under the same permeability, different TPGs were observed in four oil phase zones. It is important to note that oil properties of near-miscible flooding and miscible flooding are very close, it can be inferred that CO_2 near-miscible flooding, once achieved, is also an effective development method [23]. Besides, CO_2 can also extract the light components of the residual oil after gas breakthrough, the TPGs of the residual oil zone for the target reservoir is only 0.0083~0.0151 MPa/m, and the properties of crude oil were the best in the four phase zones. For the targeted reservoirs with CO_2 injection, compared with the original oil phase zone, the TPGs of the displacement front and miscible zones decreased by 23.4%~27.2% and by 80.1%~87.4%, respectively. The lower the permeability is, the greater the reduction of seepage resistance is. Seepage capacity increased exponentially for the permeability of the natural cores less than 4×10^{-3} μm^2.

(2) Seepage capacity of multiple oil phase zones

To reflect the effect of both pore scale and property improvement of crude oil with CO_2 injection on seepage capacity, mobility, instead of permeability, is introduced for building a chart of modified TPGs in the X oilfield. The definition of mobility is the ratio of effective modified permeability to fluid viscosity, and it combines and embodies both characteristics of porous media and reservoir fluids. Figure 9 shows the fitting of modified TPG and the values of mobility, which presents exponential distribution with a high correlation (R^2=0.9488). First of all, it can be observed that the modified TPGs of all phase zones for tight reservoirs are bigger than those of the other reservoirs, and on the whole seepage capacity of low permeability reservoir is the best. It is demonstrated that the pore scale effect, which is the intrinsic attribute of the reservoir, determines the seepage capacity of the fluids. However, it can be improved by the CO_2 injection.

In addition, it can be seen that the modified TPG of the original oil phase zone was the biggest for all three kinds of oil reservoirs, representing the initial conditions of the reservoir without CO_2 injection. The worse the physical properties are, the stronger the seepage resistance is. CO_2 injection can enhance the seepage capacity, especially when it comes to low permeability and tight reservoirs. Hence, CO_2 injection, especially near miscible/miscible flooding, is crucial for the enhancement of seepage capacity in low permeability and tight reservoirs.

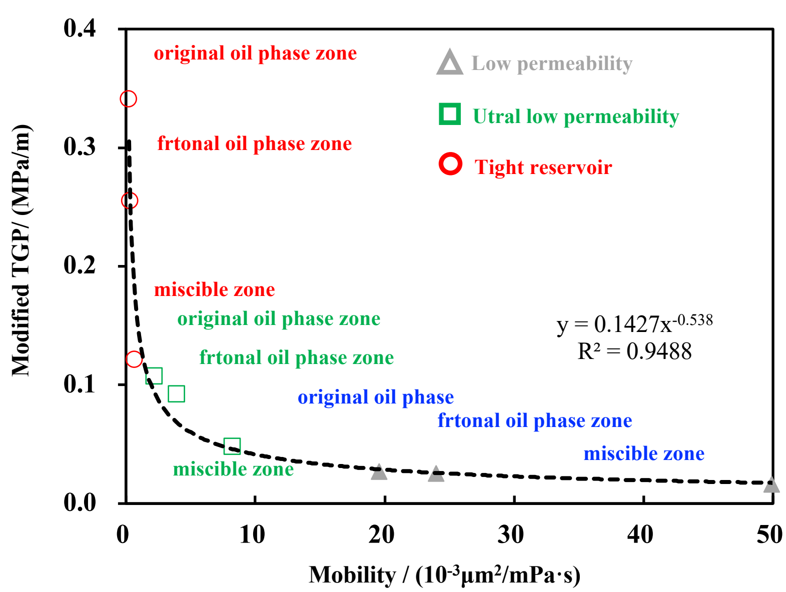

Figure 9. The relationship between modified TGP and mobility

Moreover, it can be seen that seepage resistance increased exponentially after the mobility was less than 7×10^{-3} $\mu m^2/mPa\cdot s$, but it was not obvious when the mobility exceeded the inflection point. Thus, in order to enhance the seepage capacity, mobility can be increased by either improvement of the effective permeability or reduction of the viscosity of the oil. For example, artificial fracturing can be used to increase the reservoir permeability, while CO_2 injection can be implemented to improve the properties of crude oil, as well as to enlarge the seepage channel through chemical interaction with the reservoir minerals.

Conclusions

In this work, the effects of pore size and miscible type on seepage capacity for low permeability and tight reservoirs were comprehensively studied by a series of experiments, such as modified TPG tests, relative permeability of live oil tests, and long core CO_2 displacement tests. Besides, the effect of CO_2 improvement on the seepage capacity of fluid in different permeability reservoirs was also analyzed. The results were as follows:

(1) The pore size effect can significantly reduce the seepage capacity of fluid for low permeability and tight reservoirs. Especially, when the core permeability was less than 4×10^{-3} μm^2, the TPG increased exponentially. But, when the core permeability was larger than 15×10^{-3} μm^2, the TPG was not significant, with the result that a small pressure gradient can change the flow from non-linear to linear.

(2) The contact and component mass transfer between the CO_2 and the oil were dynamic processes, CO_2 injection can improve the oil properties. Compared with the original oil phase zone, the TPG of the frontal oil phase zone and miscible zone decreased by 23.4%~27.2% and 80.1%~87.4%, respectively. Furthermore, after the gas breakthrough, CO_2 can also extract the light components from the residual oil, and the TPG of the residual oil phase zone for the tight reservoir was only 0.0083~0.0151 MPa/m.

(3) Mobility can reflect both the effect of pore size and properties of crude oil. CO_2 injection has the greatest improvement in the seepage capacity of tight reservoirs, but improvement in the seepage capacity of higher permeability was not obvious. Seepage resistance increased exponentially when the mobility was less than 7×10^{-3} $\mu m^2/mPa\cdot s$.

(4) Compared with immiscible flooding, the two-phase zone of near miscible flooding was significantly expanded by 16.3%, and residual oil saturation was lower, which meant stronger seepage capacity and greater recovery efficiency. On the other hand, compared with miscible flooding, the two-phase zone of near miscible flooding was slightly decreased, and residual oil saturation was increased by 15.7%. However, the significantly falling gas permeability under residual oil of near miscible flooding improved sweep efficiency, leading to recovery close to the miscibility.

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