Functions of capillary pressure and dissolution in the CO₂-flooding process in low-permeability reservoirs

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Abstract

CO₂ flooding has become one of most effective methods to improve oil recovery in low-permeability reservoirs. Thus, influencing factors have been specifically analyzed for their impact on oil displacement. Factors that are difficult to observe, such as capillary pressure and CO₂ dissolution, have often been neglected in specific analysis. To do so, this paper combined laboratory experimentation with numerical simulation analysis to understand the specific functions of capillary pressure and CO₂ dissolution in the CO₂-flooding process in low-permeability reservoirs. Based on laboratory experiments with long cores applying different CO₂-flooding methods, the authors established a one-dimensional numerical simulation model for CO₂ flooding. After that, the model was simulated to analyze the effects of capillary pressure and CO₂ dissolution for different CO₂-flooding processes. The results show that the function of capillary pressure in different CO₂-flooding modes is not consistent in low-permeability reservoirs; furthermore, capillary pressure is a driving force in the process of flooding and is a resistance force in the CO₂-flooding process after pressure recovery. When considering CO₂ dissolution in different flooding modes, its function was shown to be inconsistent in low-permeability reservoirs compared with CO₂ flooding without considering CO₂ dissolution; oil recovery is reduced in the CO₂-flooding process, but oil recovery increases in the CO₂-flooding process after pressure recovery. Therefore, in order to promote the rational and effective development of low-permeability reservoirs, it is necessary to understand the functions of capillary pressure and CO₂ dissolution clearly in the process of CO₂ flooding.

Keywords Dissolution · Capillary pressure · Low-permeability reservoir · CO₂ displacement · Pressure recovery

Introduction

Because CO₂ has good effects on injection and oil displacement (Ghasemi et al. 2018; Huang et al. 2016; Di et al. 2011), CO₂ flooding has become one of the most effective methods for improving oil recovery in low-permeability reservoirs (Li et al. 2018; Zhou et al. 2018; Shen and James 2018). But research on the CO₂-flooding effect in low-permeability reservoirs has been specific to the influencing factors that are easily observable, such as injection speed, injection pressure, number of injected pore volumes (PVs), oil production speed, different components, and various

injection modes (Zhao et al. 2018; Chen et al. 2010; Cerasi et al. 2016; Huang et al. 2019; Cui et al. 2018; Zhou et al. 2016). However, for the influencing factors that are difficult to observe, research usually has not included specific analysis (Huang et al. 2018; Tang et al. 2016; Zhou et al. 2017; Wang et al. 2015; Huang et al. 2017), has been less detailed, or has neglected to include capillary pressure and CO₂ dissolution.

Capillary pressure shows different functionalities (Abbasi et al. 2018; Shams et al. 2015; Hashmet et al. 2012; Carpenter 2015) under different reservoir properties and displacement modes in the process of CO₂ flooding in low-permeability reservoirs. It is generally believed that capillary pressure is powered when the wetting phase drives the non-wetting phase and is resistance when the nonwetting phase drives the wetting phase. However, in the development of CO₂ flooding for a low-permeability reservoir, the wetting and nonwetting phases do not drive one another, so the function of capillary pressure is difficult to confirm in the process

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of CO₂ flooding. However, because of the threshold pressure gradient in the seepage of low-permeability reservoirs, the seepage law for this reservoir type is different from conventional and high-permeability reservoirs (Shams et al. 2015; Hashmet et al. 2012). At the same time, production is influenced by capillary pressure during the development of a low-permeability reservoir. Presently, CO₂ flooding has various methods (Li et al. 2018; Zhou et al. 2018; Shen and James 2018; Zhao et al. 2018), and there are limited research studies on (or research studies have ignored) the function of capillary pressure in the reservoir development process.

Secondly, because of the physical properties of CO₂, its dissolution ability in water is far greater than conventional hydrocarbon. There is always some water or aquifer in low-permeability reservoirs, existing as irreducible water, coexisting water in formation, edge water, or bottom water, and generally the water volume is much larger than the oil volume. There may be a high amount of CO₂ dissolving in formation water when CO₂ is injected into the reservoir, which then impacts the effect of the flooding. At present, scholars have performed plenty of research on CO₂ dissolved in many kinds of fluids during the process of flooding (Dara et al. 2017; Zhou et al. 2018, 2019, 2020a, b; Nanta et al. 2017; Tsakiroglou et al. 2013; Shimokawara et al. 2017; Tham 2015; Feser and Gupta 2018), including the following: (1) the solubility of CO₂ in formation water increases with increasing pressure and decreases with increasing temperature. The solubility of CO₂ is slightly affected by pressure and temperature when it reaches certain temperature and pressure conditions. (2) Relative permeability is influenced by dissolution in the process of CO₂ flooding. The oil flow is useful as CO₂ properties, with results including enhanced oil-phase flow and reduced water flow, which reduce residual oil saturation and enhance oil recovery. (3) Factors exist that influence the flooding effect when considering CO₂ dissolution in fluids. The higher the water saturation, the greater the influence on oil flooding. All previous research has shown that CO₂ dissolution impacts flooding effect, but specific studies on the degree of influence of CO₂ dissolution and different flooding modes are few, and it has not been made clear how the oil displacement effect impacts CO₂ dissolution under different flooding modes.

Therefore, based on different CO₂-flooding modes in long-core laboratory experiments, the research object of this paper is the functions of capillary pressure and CO₂ dissolution in the CO₂-flooding process in low-permeability reservoirs, and the research method combines laboratory experimentation with numerical simulation to analyze the results. Firstly, the authors carried out long-core laboratory experiments in different CO₂-flooding modes. Secondly, researchers established a one-dimensional (1D) numerical simulation model for CO₂ flooding based on laboratory experiments and analysis and matching of the production

process to determine the related properties. Then, the functions of capillary pressure and CO₂ dissolution were analyzed in different flooding modes by numerical simulation. The results show that the functions of capillary pressure and CO₂ dissolution in different flooding modes are inconsistent in low-permeability reservoirs: (1) Capillary pressure is a driving force in the process of CO₂ flooding and serves as a resistance force in the CO₂-flooding process after pressure recovery. (2) Compared with not considering CO₂ dissolution in CO₂ flooding, oil recovery is reduced in the CO₂-flooding process and is increased in the CO₂-flooding process after pressure recovery.

Experiment

Experimental materials and setup

Using long-core laboratory experiments to perform CO₂-flooding experiments, 22 cores were selected from a low-permeability reservoir, with a total length of 973.44 mm, a harmonic average permeability of 2.261 mD, an average diameter of 25.39 mm, and a total pore volume of 45.01 cm³. Each core was arranged according to the BRA law. The fluid composition used in the experiment is shown in Table 1, with a gas–oil ratio of 67.2 m³/t, a degassing oil molecular weight of 294.92 g/mol, and a degassing oil density of 0.858 g/mL at 20 °C. The experimental equipment mainly included a corrosion-resistant core clamp, high-pressure physical apparatus, high-pressure matching device,

Table 1 Fluid composition of experiment

Component	Associated gas composition mol%	Degassed oil composition		Fluid composition mol%
		g%	mol%	
N ₂	0.02	–	–	0
CO ₂	1.74	–	–	0.817
CH ₄	42.37	–	–	19.897
C ₂ H ₆	17.72	–	–	8.318
C ₃ H ₈	23.90	–	–	11.218
<i>i</i> -C ₄ H ₁₀	2.58	–	–	1.211
<i>n</i> -C ₄ H ₁₀	8.33	–	–	3.910
<i>i</i> -C ₅ H ₁₂	1.49	–	–	0.699
<i>n</i> -C ₅ H ₁₂	1.87	–	–	0.878
C ₆ H ₁₄	–	0.7	2.401	1.2735
C ₇ H ₁₆	–	1.6	4.719	2.503
C ₈ H ₁₈	–	1.7	4.398	2.333
C ₉ H ₂₀	–	3.0	6.912	3.667
C ₁₀ H ₂₂	–	3.3	6.854	3.636
C ₁₁ ⁺	–	89.7	74.717	39.638
Sum	100.000		100.000	100.000

high-pressure metering pump, constant-temperature box, oil–gas separator, gas flowmeter, high-pressure drop ball viscometer, etc. (the temperature range was 20 to 200 °C with an accuracy of 0.1 °C, and the pressure range was 0.1 to 70 MPa with an accuracy of 0.01 MPa). The experimental process is shown in Fig. 1.

Experimental procedure

1. Firstly, the cores were installed according to the core sequence, the core system was vacuumed, and the saturated core was injected into the formation water. The saturation time was determined by the difference between the saturation volume and the pore volume. The saturation was recorded at the experimental temperature, and the pressure was steadied when the cores were fully saturated.
2. Because of the high viscosity of saturated crude oil, low viscosity of water, and low formation permeability, in order to establish the distribution of the initial oil and water in the formation, the saturated oil was used in the experiment to flood water in the long core.
3. The long-core flooding experiments were carried out under the conditions of formation temperature and pressure.

4. During the experiment, the displacement time, pump reading, injection pressure, injection speed, ring pressure, and back pressure were recorded, and the oil, gas, and water were monitored after separating. In order to test the start-up pressure of low-permeability reservoirs, the PV was recorded starting with the first drop of oil.
5. The cores were cleaned after each experiment, first with petroleum ether and then anhydrous alcohol. Then, the core was blown with nitrogen and dried.
6. Steps 1 and 2 were repeated to carry on the next group experiments after the formation of the original state.

Experimental scheme

Two groups of experiments were set up; the core parameters are shown in Table 2. Experiment 1 was a flooding experiment, with an injection gas pressure of 12.9 MPa, an injection gas of CO₂, and an injection speed of 0.5 mL/min; the output end maintained the open state during the experiment. Experiment 2 was a pressure-recovery flooding experiment. The core was injected with CO₂ at a certain gas injection rate until the core was pressed to 20 MPa before the experiment, and then the CO₂ injection rate of 0.5 mL/min was injected into the core, and the oil recovery process was carried out by CO₂ flooding.

Fig. 1 CO₂-flooding experimental device

Table 2 Core parameters of experiment

Experimental scheme	Saturated water volume in core (mL)	Saturated oil volume in core (mL)	Oil saturation (%)	Irreducible water saturation (%)
Flooding experiment (1)	49.5	32.1 (27.54 g)	64.85	35.15
Flooding experiment after pressure recovery (2)	48.20	31.90 (27.37 g)	66.18	33.82

Fig. 2 Production rate and cumulative oil production curves in the CO₂-flooding experiment

Analysis of experimental results

Experiment 1

In the CO₂-flooding experiment, the injection well was injected with CO₂ gas into the core at a speed of 0.5 mL/min, and the oil production rate curve and cumulative oil production curve were produced (see Fig. 2). Oil production rate rose rapidly in the early stage of gas injection and hit a peak of 0.293 g/min when the experiment time was at 55 min. At the experiment time of 240 min, the oil production rate fell to less than 0.001 g/min; the experiment showed negligible increase in oil production. After 600 min, the oil production rate was basically 0 g/min. The accumulation of oil production tended to be constant; cumulative oil production was 10.73 g, and recovery degree was 38.96% at 600 min. Finally, cumulative oil production was 10.85 g and recovery degree was 39.41%. Generally, oil production was mainly concentrated in the early stage in the CO₂-flooding experiment.

Experiment 2

In the pressure-recovery flooding experiment, the core pressure was restored to 20 MPa in the pressure-recovery stage, the injection well was injected with CO₂ gas into the core at a speed of 0.5 mL/min, and the bottom pressure of the production well was maintained at 20 MPa; Fig. 3 shows the oil production rate curve and the cumulative oil production curve. The experimental results showed the following: (1) at 442 min into the pressure-recovery process, the model pressure rose to 20 MPa. (2) After the production well opened, CO₂ gas slowly advanced to the bottom of the production well at the beginning of the 50-min point because the difference in production pressure had not been established; the production well did not have oil, and after the well was

Fig. 3 Production rate and cumulative oil production curves in the CO₂ pressure-recovery flooding experiment

open for 50 min, the difference in production pressure was established between the injection and the production wells, at which point oil was the product in the production well. (3) Because of the CO₂ gas being saturated in the fluid of the core in the pressure-recovery process, the oil production rate reached its peak (0.382 g/min) immediately after the well went into oil production. (4) After the CO₂ gas broke through the injection and production wells, the oil production rate curve rapidly decreased without a change in trend because the oil production mainly came from a condensate of hydrocarbon components brought out by CO₂; cumulative oil production was 13.161 g, and recovery degree was 48.09%. Finally, the cumulative oil production was 13.64 g, and recovery degree was 49.85%. In general, during the CO₂ pressure-recovery flooding experiment, oil production was mainly concentrated in the early stage of the production well opening after pressure recovery.

Analysis of the functions of capillary pressure and dissolution in different CO₂-flooding modes

Numerical simulation model

Based on the two groups of long-core experiments, a 1D three-phase (oil/gas/water) component model was established in numerical simulation, and the component model in the reservoir simulation software was brought into the simulation. Each core was divided into five grids on average, and the 1D models had 110 grids in numerical simulation. Among them, the injection well was located in the first grid to represent the injection port, and the production well was located in the 110th grid to represent the production port.

Fig. 4 Cumulative production match curves in CO₂-flooding experiment

Fig. 5 Cumulative production match curves in CO₂-flooding experiment after pressure recovery

Firstly, the two groups of experiments were matched (see Figs. 4, 5). Meanwhile, a numerical simulation model was established considering CO₂ dissolution, and then calculation and analysis were carried out to obtain the oil displacement effect under the different conditions of capillary pressure and CO₂ dissolution.

Analysis of the function of capillary pressure in different CO₂-flooding modes

The function of capillary pressure in the CO₂-flooding process

Based on the good match and the other physical parameters remaining unchanged in the experiment, two conditions were found with which to analyze the function of capillary pressure in the CO₂-flooding process through numerical simulation: increase in capillary pressure and decrease in capillary

Fig. 6 Capillary pressure curve for different schemes (experiment 1)

Table 3 Capillary pressure function parameters in the CO₂-flooding process

Project	Peak pressure (MPa)	Peak production rate (g/min)	Cumulative oil production (g)	Recovery degree (%)
Initial	13.78	0.300	10.85	39.41
2 times	13.61	0.235	11.18	40.59
0.25 times	14.27	0.249	10.60	38.49

pressure (see Fig. 6). The results showed that the higher the capillary pressure, the higher the cumulative oil production and recovery degree—the capillary pressure being a driving force in the process of CO₂ flooding.

The capillary pressure increased two times, and the valve pressure of the core changed slightly, but the peak pressure decreased from 13.77 to 13.61 MPa, and the corresponding peak time of arrival decreased from 81 to 71 min (see Table 3 and Fig. 7). The time to oil production decreased, and the peak time decreased from 67 to 55 min, increasing cumulative oil production and recovery degree (see Table 2 and Fig. 8). Increasing the capillary pressure decreased the resistance of CO₂ into the core, decreased the pressure peak, and decreased the energy loss, leading to increased injection power of CO₂, increased contact area and degree of dissolution between CO₂ and oil, increased flooding speed in the core, and increased displacement efficiency. In general, capillary pressure showed a significant impact in this experiment.

The capillary pressure decreased 0.25 times, the valve pressure of the core increased from 13.28 to 13.35 MPa, the peak pressure increased from 13.77 to 14.27 MPa, and the corresponding time-of-arrival peak increased from 81 to 100 min (see Table 2 and Fig. 7). The time to oil production increased, the peak production rate decreased from 0.30 to 0.249 g/min in

Fig. 7 Injection pressure curve under different capillary pressures (experiment 1)

Fig. 8 Oil production rate curve under different capillary pressures (experiment 1)

the production process, and the peak time increased from 67 to 90 min (see Table 2 and Fig. 8). Decreasing the capillary pressure increased the resistance of CO_2 into the core, increased the valve pressure, increased the pressure peak, and increased the energy loss, leading to decreased injection power of CO_2 and decreased contact area and degree of dissolution. As for the relationship between CO_2 and oil, wave area decreased, as did displacement efficiency, cumulative oil production, and recovery degree. Capillary pressure was further proved to be a driving force in this experiment.

The function of capillary pressure in the CO_2 pressure-recovery flooding process

Based on the good match and the other physical parameters remaining unchanged in the experiment, two conditions

were found with which to analyze the function of capillary pressure in the CO_2 pressure-recovery flooding process through numerical simulation: increase in capillary pressure and decrease in capillary pressure (see Fig. 9). The results showed that the higher the capillary pressure, the lower the cumulative oil production and recovery degree; the capillary pressure was shown to resist the process of CO_2 pressure-recovery flooding.

The capillary pressure increased five times, the effect was low on production and injection pressure, the peak time remained basically the same, and the cumulative oil production and recovery degree decreased slightly (see Table 3, Figs. 10, 11). Increasing the capillary pressure increased energy loss, leading to decreased CO_2 injection power, decreased contact area and degree of dissolution between CO_2 and oil, decreased wave area, and decreased displacement efficiency. In general, capillary pressure expressed resistance in this experiment.

The capillary pressure decreased 0.25 times, there was low effect on production and injection pressure, and cumulative oil production and recovery degree rose slightly (see Table 4, Figs. 10, 11). Capillary pressure was further proved to be resistant in this experiment.

Analysis of the function of dissolution in different CO_2 -flooding modes

The function of dissolution in the CO_2 -flooding process

Based on the good match and the other physical parameters remaining unchanged in the experiment, two conditions were found with which to analyze the function of dissolution in the CO_2 -flooding process through numerical simulation: considering CO_2 dissolution and not considering

Fig. 9 Capillary pressure curve for different schemes (experiment 2)

Fig. 10 Injection pressure curve under different capillary pressures (experiment 2)

Fig. 11 Oil production rate curve under different capillary pressures (experiment 2)

Table 4 Capillary pressure function parameters in the CO₂ pressure-recovery flooding process

Project	Peak pressure (MPa)	Peak production rate (g/min)	Cumulative oil production (g)	Recovery degree (%)
Initial	22.09	0.390	13.64	49.85
5 times	21.98	0.361	12.99	47.46
0.25 times	22.12	0.391	13.73	50.16

CO₂ dissolution (see Table 5 and Figs. 12, 13, 14). The results showed that when comparing consideration and nonconsideration of CO₂ dissolution, the peak production rate decreased from 0.30 to 0.265 g/min, and the peak time slowed slightly. The peak pressure decreased from 13.78 to 13.61 MPa, cumulative oil production decreased from 10.85 to 10.38 g, and recovery degree decreased from

Table 5 Dissolution function parameters in the CO₂-flooding process

Project	Peak pressure (MPa)	Peak production rate (g/min)	Cumulative oil production (g)	Recovery degree (%)
No dissolution	13.78	0.300	10.85	39.41
Dissolution	13.61	0.265	10.38	37.72

Fig. 12 Oil production rate curve contrasting dissolution and no dissolution (experiment 1)

Fig. 13 Injection pressure curve contrasting dissolution and no dissolution (experiment 1)

39.41 to 37.72%. When CO₂ dissolution was considered during the flooding process, CO₂ gas was used to saturate fluids in the model at the start, thus delaying the flooding process, reducing the production pressure difference, expanding the breakthrough time, and decreasing the peak production rate, leading to reduced efficiency of displacement crude oil in this experiment.

Fig. 14 Cumulative oil production curve contrasting dissolution and no dissolution (experiment 1)

Table 6 Dissolution function parameters in the CO₂ pressure-recovery flooding process

Project	Peak pressure (MPa)	Peak production rate (g/min)	Cumulative oil production (g)	Recovery degree (%)
No dissolution	22.09	0.390	13.64	49.85
Dissolution	22.19	0.415	14.07	51.40

The function of dissolution in the CO₂ pressure-recovery flooding process

Based on the good match and the other physical parameters remaining unchanged in the experiment, two conditions were found with which to analyze the function of dissolution in the CO₂ pressure-recovery flooding process through numerical simulation: considering CO₂ dissolution and not considering CO₂ dissolution (see Table 6 and Figs. 15, 16, 17). The results showed that when comparing the consideration and nonconsideration of CO₂ dissolution, peak production rate increased from 0.390 to 0.415 g/min, peak pressure increased from 22.09 to 22.19 MPa, cumulative oil production increased from 13.64 to 14.07 g, and recovery degree increased from 49.85 to 51.40%. When CO₂ dissolution was considered during the pressure-recovery flooding process, the fluid was saturated with CO₂ in the model at the stage of pressure recovery, and CO₂ gas was completely used for displacement at the stage of flooding. At the same time, when the pressure dropped, CO₂ precipitated from the saturated fluid and took part in the flooding, increasing the production pressure difference and the oil production rate, leading to increased efficiency of displacement crude oil in this experiment.

Fig. 15 Oil production rate curve contrasting dissolution and no dissolution (experiment 2)

Fig. 16 Injection pressure curve contrasting dissolution and no dissolution (experiment 2)

Fig. 17 Cumulative oil production curve contrasting dissolution and no dissolution (experiment 2)

Conclusions

1. In the CO₂-flooding experiments, the effect of pressure-recovery flooding was shown to be better than direct flooding, with recovery increasing from 39.41 to 49.85%, an increase of 10.445%. The main reason behind this result is that pressure rise is limited during flooding experimentation. Meanwhile, pressure is higher in the process of pressure recovery, close to the minimum miscibility pressure and near-miscible drive.
2. In low-permeability reservoirs, capillary pressure is a driving force in the process of CO₂ flooding. When capillary pressure is reduced 0.25 times, recovery is reduced by 0.92%. Capillary pressure is resistant in the CO₂-flooding process after pressure recovery. When capillary pressure is reduced 0.25 times, recovery is increased by 0.31%.
3. In low-permeability reservoirs, dissolution leads to decreased displacement efficiency in the CO₂-flooding process, with recovery reduced by 1.69%. Dissolution leads to increased displacement efficiency in the CO₂ pressure-recovery flooding process, with recovery increased by 1.55%.
4. Capillary pressure and dissolution affect the production of low-permeability reservoirs and cannot be ignored in field development, as shown by the only theoretical response of capillary pressure and dissolution in the numerical simulation presented in this study. Later studies could suggest the microscopic functions of capillary pressure and dissolution by physical experimentation to demonstrate the mechanism of action and to establish the related models.

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