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ARTICLE

Study of CO_2 Flooding to Improve Development Effect in Conglomerate Reservoirs

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ABSTRACT

For low permeability sandstone reservoirs, CO_2 flooding has been proved to be an effective method to enhance oil recovery. Reservoir A is a typical conglomerate reservoir in Xinjiang oilfield. The reservoir has strong water sensitivity, and the injection pressure continues to rise. Furthermore the oil well pressure continues to drop. According to the screening conditions of CO_2 flooding, the reservoir A can easily achieve CO_2 miscible flooding with moderate temperature. And the reservoir has the advantage of being close to the gas source. Firstly, the relationship curve between CO_2 oil displacement efficiency and oil displacement pressure was obtained by changing the oil displacement pressure using the fine-tube experimental model, and the minimum miscible pressure of CO_2 oil displacement was determined. The minimum miscible pressure of reservoir A was 24.1 MPa. The change of oil phase state after CO_2 injection was further studied by CO_2 gas expansion experiment. The results show that the saturation pressure of formation oil increases significantly after CO_2 injection, and the more CO_2 injection, the higher the saturation pressure of formation oil. When the CO_2 content in the injected crude oil is 55.29 mol%, the saturation pressure of the CO_2 formation crude oil system reaches 31.60 MPa. Then, in order to better simulate the real reservoir conditions of conglomerate reservoir, the 2D visualization model of the outcrop was processed to analyze the microscopic oil displacement mechanism of CO_2. The experimental results show that the remaining oil after water flooding mainly exists in the form of cluster, film, column and blind end, and the remaining oil after gas flooding exists in the form of island, cluster and film, and there is an obvious gravity overlay phenomenon. CO_2 flooding after water flooding significantly improved sweep efficiency and enhanced recovery. Finally, through the analysis of CO_2 field injection effect in reservoir A, it is shown that CO_2 absorption capacity of single well is significantly higher than water absorption capacity. The equilibrium degree of production profile in gas injection stage is better than that in water flooding stage. Injecting carbon dioxide quickly restores formation pressure. The oil recovery effect after gas injection in the trial production stage is obviously improved compared with that in the water flooding stage. The research results of this paper provide a reference for the field application of CO_2 flooding enhanced oil recovery technology in Xinjiang conglomerate reservoir.

KEYWORDS

CO_2 flooding; physical simulation; miscible pressure; enhanced oil recovery

1 Introduction

With the increasingly complex development of new oil fields, new problems in the development of oil fields in Xinjiang are becoming more and more prominent [1]. The growth of new proven reserves continues to be strong [2,3], but mainly low permeability and extra-low permeability reserves. And it is urgent to explore new development methods [3,4]. Low permeability and ultra-low permeability reservoirs account for increasing proportion of thin oil production, and there are some problems such as injection-production contradiction [5,6], low reservoir pressure and poor water drive development effect make it difficult to achieve standard recovery [7]. The developed oilfields in Xinjiang oilfield are generally in the middle and late stage of high water cut, high decline, low oil production rate and low efficiency. So it is necessary to study new development methods including CCUS to further improve oil recovery [8–10].

The development of CO_2 oil flooding technology in the United States was relatively early, with basic research carried out in 1950 [11,12], the first patent application for CO_2 oil flooding technology in 1952, and the commercialization and promotion of the technology [13,14], which took 30 years. It has gone through four stages: basic research, technology research, industrial testing and commercial promotion, and has formed a series of supporting technologies [15,16]. In the industrial test stage, it has been verified that CO_2 mixed-phase flooding can significantly improve the recovery rate [17,18], and has developed dynamic monitoring technology of CO_2 oil flooding [19], CO_2 oil flooding adjustment technology represented by water-gas alternation and economic evaluation technology of CO_2 oil flooding engineering system [20,21]. In the commercial promotion stage, it has developed integrated technology of large PV injection CO_2 oil flooding and burial [22,23], chemically assisted mixing reduction and flow control technology [24], output gas recycling technology and gravity stabilization flooding technology and gravity stabilization flooding technology [25].

Since the commercial promotion in the 1980s, with the development and progress of technology, the annual oil production of CO_2 flooding has been increasing [26], and the current annual oil production is above 13 million tons [27]; the magnitude of recovery enhancement has also increased greatly compared with 20 years ago, and the average recovery enhancement abroad is 10%–20%, with the highest value reaching 30% [28].

So far, relevant data show that CCUS and its application have been carried out worldwide and achieved remarkable results [29]. CCUS pilot tests or industrial tests have been carried out in Jilin oilfield and Daqing oilfield of CNPC, and certain results have been achieved, but no relevant studies have been carried out for conglomerate reservoirs with strong inhomogeneity, especially for strongly water-sensitive low-permeability conglomerate reservoirs. Therefore, the objectives of this study are to explore cost-effective methods to improve the recovery rate of developed conglomerate reservoirs and to explore ways to effectively utilize the new proven low-permeability reserves. Firstly, the minimum miscible pressure of CO_2 flooding was determined by using the thin tube experiment model, and then the change of oil phase state after CO_2 injection was further studied by CO_2 gas expansion experiment. Then, in order to better simulate the real reservoir conditions of conglomerate reservoir, a two-dimensional plane visualization model is used to analyze the microscopic oil displacement mechanism of CO_2. Finally, the development effect of CO_2 flooding was evaluated according to the development dynamics of CO_2 test injection well group in reservoir A.

2 Selection of CO_2 Flooding Test Area for Conglomerate Reservoirs

2.1 Selection of Test Area

The selection principle of CO_2 flooding test area of conglomerate reservoir in Junggar basin is as follows. (1) The pilot area is representative. (2) The CO_2 flooding test area has great potential of remaining oil after water flooding. (3) There should be sufficient CO_2 gas source near the CO_2 flooding test area. (4) The well condition of injection production well pattern in CO_2 flooding test area remains good.

The selected reservoir has obvious characteristics of low permeability, strong water sensitivity, strong velocity sensitivity and strong salt sensitivity. There are prominent contradictions such as continuous rise of injection pressure of water injection wells, serious shortage of water injection, continuous decline of oil well pressure, insufficient liquid supply and so on. In order to improve reservoir recovery, it is urgent to change the oil displacement mode. According to the screening conditions of CO_2 miscible flooding, the reservoir has moderate temperature and large oil saturation pressure difference, which is easy to meet the conditions of CO_2 miscible flooding. At the same time, the reservoir has the advantage of being close to CO_2 gas source. After the successful test, the conditions for popularizing CCUS test project are met. Therefore, it is decided to conduct CCUS pilot test for this reservoir.

2.2 Overview of Reservoir in Test Area

The structural form of the target area is simple, which is a southeast inclined monoclinic layer. The internal faults are not developed, and the dip angle of the stratum is only 2°–5°. The buried depth of the test area is 2530.0~2677.5 m, the average buried depth is 2617.0 m, the stratum thickness is 147.5~206.0 m, and the average stratum thickness is 173.7 m, of which the stratum thickness of main layer S7 is 118.2~129.2 m, and the average stratum thickness is 123.6 m. The target area is fan delta facies, and the provenance direction is NW.

According to the analysis of core data, the reservoir porosity range in the target area is 2.71%~20.31%, with an average of 10.32%, and the reservoir permeability range is 0.02~1576.27 mD, with an average of 2.11 mD.

The test area has been put into operation since 1996. From 2011 to 2012, the reverse seven point well pattern was adopted to enter the comprehensive development stage. The injection production well spacing is 200 m. A total of 58 wells were put into operation, including 43 oil wells and 15 water wells. As of January 2019, the current daily water injection is 67.55 m^3, and the cumulative water injection is 36.21×10^4 m^3. The daily oil production is 12.23 t, and the cumulative oil production is 20.87×10^4 t, cumulative liquid production is 45×10^4 t, the comprehensive water cut of the reservoir is 63.97%, the recovery degree of the reservoir is 10.83%, the monthly injection production ratio of the reservoir is 1.55, the cumulative injection production ratio is 0.59, and the cumulative deficit volume is 24.91×10^4 m^3.

2.3 Residual Oil Potential in the Target Area

Based on the current well network, the water-flooding recovery rate of the test area was calibrated at 13.4% using the decreasing method, the degree of recovery *vs.* water content method, and the numerical model method. The gas-flooding recovery rate is predicted to be 40% using the numerical model method.

The remaining oil in the test area contains high oil saturation, with an average remaining geological reserve of 3.8×10^4 t in a single well and an average remaining recoverable reserve of

1.22×10^4 t (gas flooding) in a single well, which is greater than the limit cumulative oil production of 1.04×10^4 t and has the potential for gas flooding adjustment. In the plane, the remaining oil is mainly concentrated in the middle of the test area; in the longitudinal direction, it is mainly concentrated in S_7^4 (Table 1).

Table 1: Statistics of remaining oil in target area

Oil bearing series	Oil bearing area (km^2)	Geologic reserves (10^4 t)	Cumulative oil production (10^4 t)	Recovery degree of crude oil (%)	Remaining geology reserves (10^4 t)	Abundance of remaining geological reserves (10^4 t/km^2)	Proportion (%)
S_7^3	2.37	31.43	2.5	7.95	28.93	12.21	16.31
S_7^4	2.6	113.79	12.03	10.57	101.76	39.14	59.05
S_7^5	2.6	43.32	7.79	17.98	35.53	13.67	22.48
Total	2.6	192.71	22.32	12.17	170.39	65.53	-

The numerical simulation results show that the oil saturation of the remaining oil in the test area is high (Fig. 1), and the oil saturation of the remaining oil near most of the wells is greater than 45%, which exceeds the lower reservoir limit for water flooding.

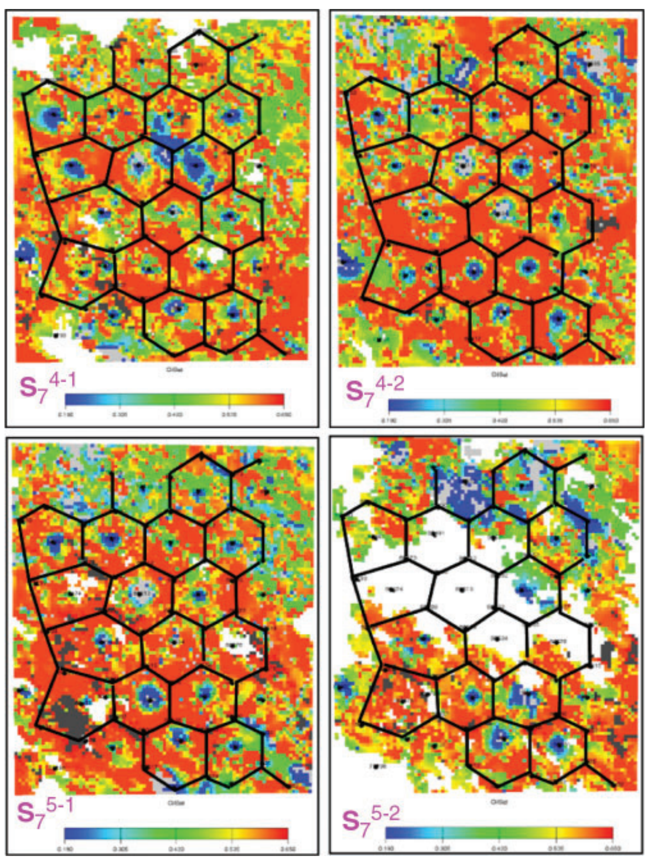


Figure 1: Distribution of remaining oil in each oil-bearing sublayer in the study area

3 Laboratory Experimental Evaluation of CO_2 Flooding

3.1 Experiment on Miscibility of CO_2 Flooding

3.1.1 Determination Method of Minimum Miscible Pressure

The experiments used the fine tube model to determine the minimum mixing pressure for CO_2 flooding by varying the repulsion pressure and obtaining the CO_2 flooding efficiency *vs.* repulsion pressure curve. The fine tube experimental method determines the multiple contact minimum mixing pressure.

3.1.2 Experimental Device and Samples

The thin-tube experimental setup used in this study was self-assembled, and the flow chart of the thin-tube experiment is shown in Fig. 2. And the main parameters of the key component of the thin-tube model are shown in Table 2.

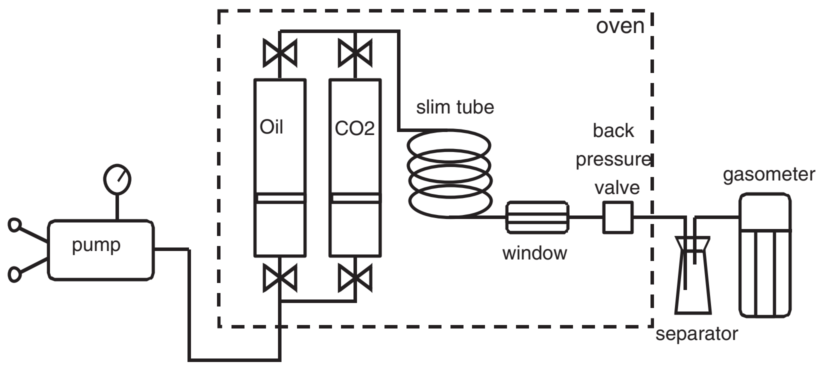


Figure 2: Flow chart of the fine tube experiment

Table 2: Basic parameters of the fine tube model

Main parameter items	Parameter value
Highest temperature	150°C
Maximum pressure	55 MPa
Length	18.3 m
Inner diameter	3.86 mm
External diameter	6.35 mm
Filler (Quartz sand)	170–325 mesh
Porosity	39%
Gas permeability	3.2 mD

The experimental samples were stratigraphic oil samples from the test area, laboratory compounding of degassed oil samples from the surface wellhead of well 80553 and natural gas. The purity of injected CO_2 is 99.95 mol%.

3.1.3 Results of the Fine Tube Experiment

Five CO_2 gas flooding thin-tube model displacement experiments were conducted at the formation temperature (65.4°C) in the test area. The displacement pressures of the five experiments were 21.2, 23.0, 25.0, 27.0 and 31.6 MPa, respectively. And the 31.6 MPa is the original formation pressure of the reservoir.

When the volume of CO_2 injected into the fine tube is 1.2 PV, the crude oil recovery degree of five thin pipe experiments in the test area is shown in Table 3. The relationship curve between recovery degree and displacement pressure is shown in Fig. 3.

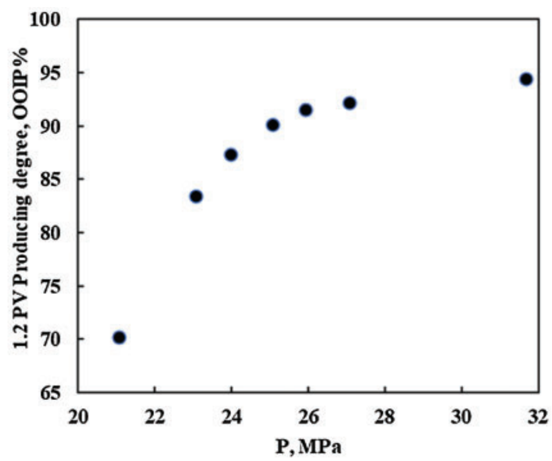


Figure 3: Relationship between the degree of CO_2 recovery from the fine tube experiment and the displacement pressure

Table 3: Results of CO_2 injection fine tube displacement experiments (experimental temperature is 65.4°C)

Serial number	Experimental pressure (MPa)	Recovery degree after injection of 1.2 PV (%)	Status
1	21.20	70.28	Immiscible phase
2	23.00	83.57	Near miscible phase
3	25.00	90.23	Miscible phase
4	27.00	92.35	Miscible phase
5	31.60	94.63	Miscible phase

The pressure corresponding to the intersection of the miscible segment and the miscible segment curve in the figure is 24.1 MPa. The degree of recovery is relatively low when the replacement pressure is less than 24.1 MPa and increases significantly with the increase of the replacement pressure, which is a non-mixed-phase replacement process; the degree of recovery is high (>95%) when the replacement pressure is greater than 24.1 MPa, and there is only a small increase in the degree of recovery when the replacement pressure continues to increase. The flooding mechanism has changed to miscible displacement. Based on the experimental data of fine tube displacement, it can be determined that the minimum miscible pressure for the crude oil to reach the mixed-phase in the reservoir of the test area is 24.1 MPa.

3.2 Formation oil Expansion Experiment with CO_2 Injection

The phase change of the crude oil in the formation in the test area after CO_2 injection was investigated by CO_2 plus gas expansion experiment. The experimental oil samples were laboratory compounded from degassed oil samples from the surface wellhead of well 80553 and natural gas. The purity of the CO_2 gas samples was 99.95 mol%. A total of seven gas expansion experiments were conducted at formation temperature.

The experimental results showed that the saturation pressure of the formation crude oil increased significantly after the injection of CO_2, and the more CO_2 was injected, the higher the saturation pressure was. When the content of injected CO_2 in formation crude oil was 55.29 mol%, the saturation pressure of CO_2-formation crude oil system reached 31.60 MPa, as is shown in Table 4.

Table 4: Experiment data of saturation pressure and phase behavior of CO_2-formation crude oil system

Filling times (s)	CO_2 mole fraction (mol%)	Saturation pressure (MPa)	Coefficient of expansion at formation pressure	Coefficient of expansion at saturation pressure	Density at formation pressure (g/cm^3)	Density at saturation pressure (g/cm^3)	Viscosity at formation pressure (mPa·s)	Viscosity at saturation pressure (mPa·s)
0	0	20.31	1	1	0.7675	0.7581	3.81	3.16
1	16.71	22.1	1.0713	1.0959	0.7541	0.7465	3.08	2.79
2	27.06	23.91	1.121	1.1468	0.7458	0.7401	2.79	2.57
3	45.4	28.28	1.2211	1.2436	0.7335	0.7319	2.42	2.41
4	55.29	31.6	1.3214	1.3214	0.7278	0.7278	2.23	2.23
5	65.4	36.57		1.4267		0.7249		2.17
6	75.9	42.96		1.5976		0.721		2.04
7	81	47.46		1.7216		0.72		1.99

The experimental results show that CO_2 has strong ability to expand and dissolve the formation oil in the test area, as well as a good viscosity reduction effect. Increasing the injection pressure, the ability of CO_2 to expand the volume of crude oil and reduce the viscosity of crude oil was enhanced, which was beneficial to improve the recovery of crude oil (Figs. 4–7).

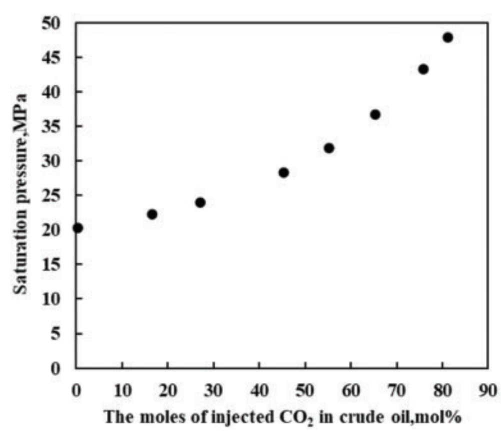


Figure 4: P-X diagram of crude oil from CO_2-injected strata

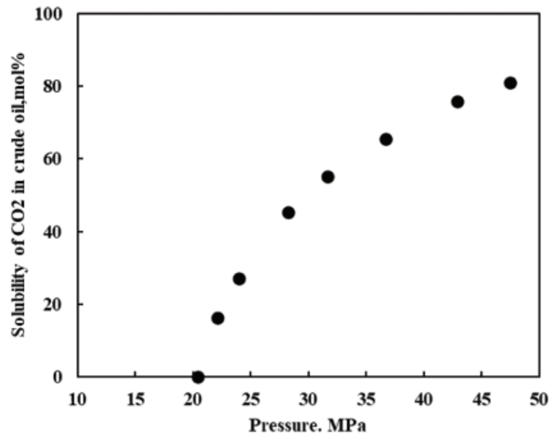


Figure 5: Solubility curve of CO_2-formation crude oil

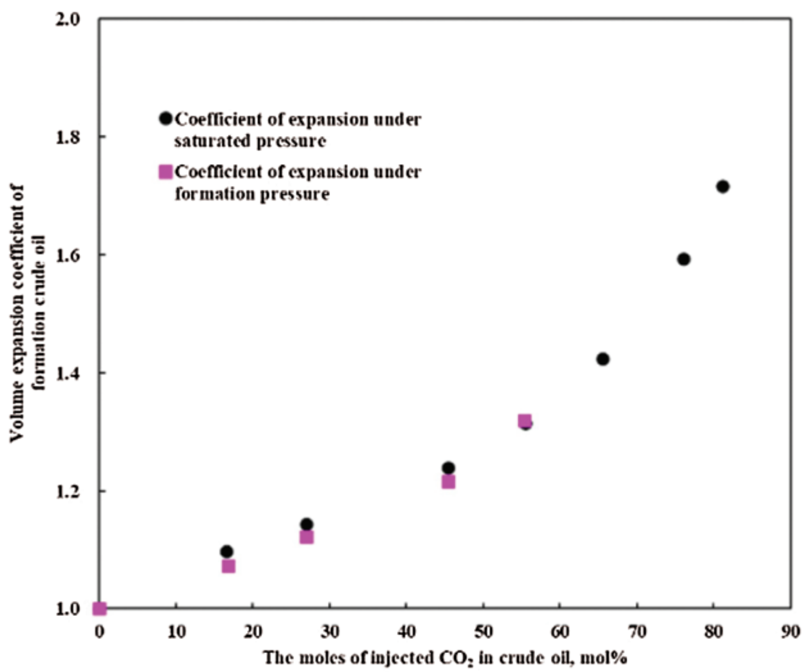


Figure 6: Volume expansion curve of CO_2-formation crude oil

3.3 Experiment of CO_2 Miscible Flooding

We selected natural cores for CO_2 oil displacement experiment, set back pressure of 24 MPa and gas injection rate of 0.3 ml/min. The experimental results showed that the water injection during water flooding broke through after about 0.64 PV, and the recovery rate was 43.42% at the breakthrough, and the water content rate increased rapidly after the breakthrough. The water content reached 100% when the water flooding reached 1.0 PV, and the water flooding recovery rate was 51.11%. After the completion of water flooding, it is transferred to gas flooding. When the gas injection is 0.4 PV, the CO_2 breakthrough occurs. At this time, the recovery factor is 52.74%. When the gas injection volume reaches 1.5 PV, gas channeling is serious, and the gas oil ratio is 2010. At this time, the recovery rate basically does not change, and the final recovery rate is 70.37%, as shown in Fig. 8.

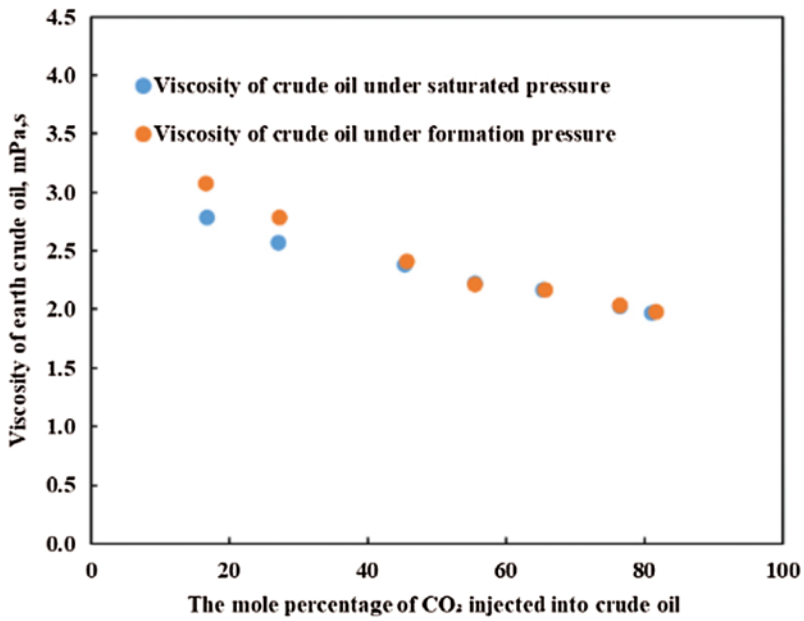


Figure 7: Viscosity curve of CO_2-formation crude oil

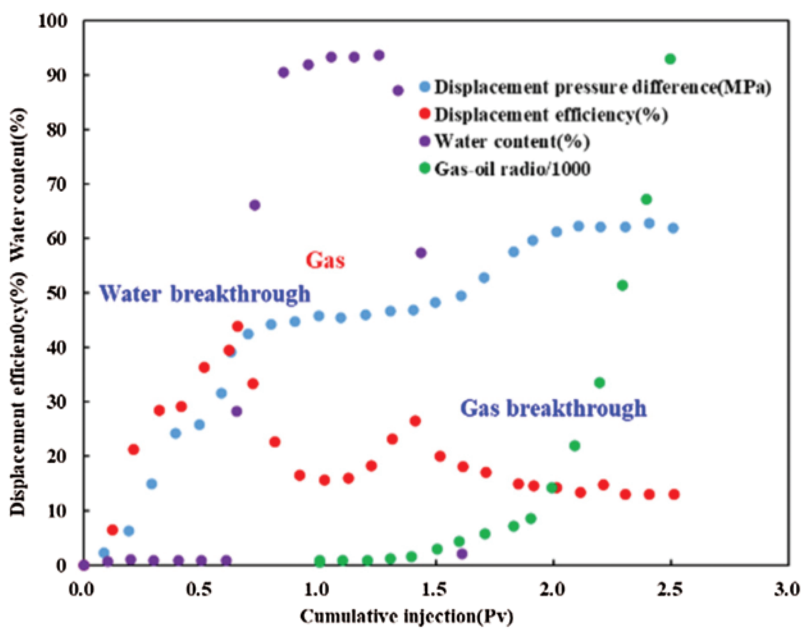
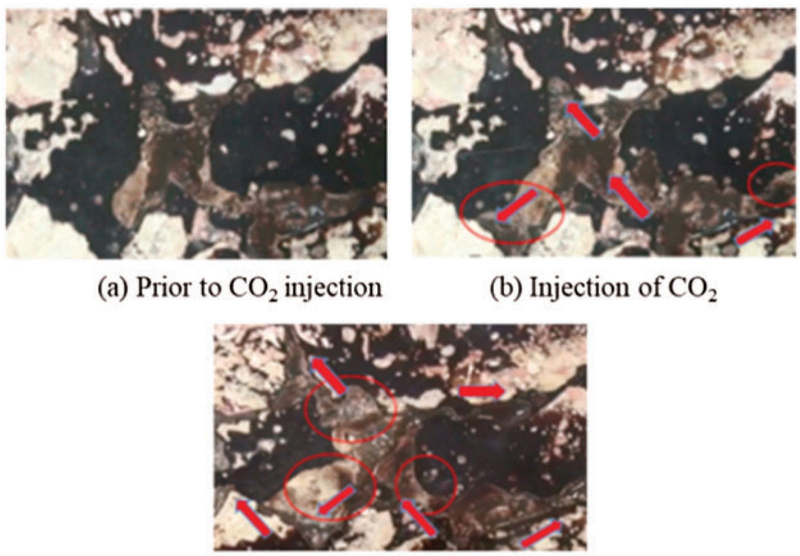


Figure 8: Water and gas flooding dynamic data (The core permeability is 9.23 mD)

In order to better simulate the real reservoir conditions of conglomerate reservoir, the outcrop is drilled from the field for processing, and a two-dimensional plane visual model is made to further analyze the micro oil displacement mechanism of CO_2.

After water flooding, the model was subjected to continuous CO_2 injection gas flooding experiment. The gas injection rate was 0.3 ml/min, and the experimental temperature was maintained at 67°C. The experimental data of gas flooding were recorded and the experimental process was observed. The results of gas drive experiment show that after CO_2 enters the model, it displaces crude oil from three directions, respectively. During the experiment, it can be clearly found that the area used in this area is becoming larger and larger. In the final stage of gas flooding, gas channeling is serious, and there is basically no oil at the outlet. After gas flooding, the oil displacement effect is greatly improved compared with water flooding, the swept area is significantly expanded, and the recovery degree is increased, as shown in Fig. 9.



(a) Prior to CO_2 injection (b) Injection of CO_2

(c) After the injection of CO_2

Figure 9: CO_2 flooding experiment process

Experimental results show that in the stage of water flooding, most of the oil phase in the large pore is driven away, while there is still a large amount of remaining oil in the small pore. In the late stage of water flooding, there is an obvious channeling channel. After CO_2 flooding, it can be found that the remaining oil is significantly reduced, and the area occupied by the remaining oil cluster is much reduced, and the gas channeling is obvious in the late stage of CO_2 flooding. The experimental results show that CO_2 flooding in conglomerate reservoir has good oil-increasing potential, but gas injection parameters should be optimized to prevent premature gas channeling from affecting its development effect.

4 Effect Analysis of CO_2 Injection Test in Well Group

In order to evaluate the reservoir suction capacity and formation pressure recovery level, and provide geological and engineering parameters for the preparation of reservoir development plan, two well groups are selected in the test area for injection test.

4.1 Basic Information on CO_2 Injection Test

Through the screening of several indicators such as well condition, cementing quality and water breakthrough effect of oil wells, well 80513 which can inject water normally and well 80534 which cannot inject water are finally selected as CO_2 injection test well group. On August 11, 2017, the two well groups started the on-site trial injection of CO_2, and the trial injection was completed in mid November, with a cumulative injection of 3789.8 t CO_2. At the same time, in order to quickly restore formation pressure and delay gas channeling, the oil well is shut in during test injection.

4.2 Development Performance Analysis of Well Group after CO_2 Injection

4.2.1 Substantial Increase in CO_2 Absorption Capacity of Single Wells Compared to Water Absorption Capacity

The injection pressure of well 80534 was 23.17 MPa at the late stage of water injection and no water could be injected; when it was changed to CO_2 injection, the injection pressure dropped to 19.5 MPa and the daily CO_2 injection volume could be maintained at about 30 t.

By comparing the water and gas injection volumes of well 80513 at the same injection pressure, it can be seen that at an injection pressure of 20 MPa, the daily water injection volume is between 12 and 20 t, and the daily CO_2 injection volume is between 50 and 60 t. The CO_2 injection capacity is about 2.5 to 3.7 times of the water injection capacity. Comparing the effective permeability of the formation before and after 80513 injection, it can be seen that there is a substantial increase in the effective permeability of the formation after CO_2 injection, from 1.88 to 6.35 mD.

4.2.2 The Profile Production Degree in Gas Injection Stage is Better Than That in Water Drive Stage

In the early stage of water injection development, the overall mobilization of well 80513 was relatively uniform, and the later suction levels were mainly concentrated in $S_7^{4\text{-}2}$ and $S_7^{5\text{-}1}$, which have better physical properties; after the CO_2 injection was changed, the initial suction profile continued the characteristics of the water-floodingn stage, with $S_7^{4\text{-}2}$ and $S_7^{5\text{-}1}$ mainly suctioned, and later, influenced by the water section plug and gas injection rate, the upper part of the reservoir with poorer physical properties was mainly suctioned.

Well 80492 had uneven profile mobilization at the early stage of water injection development, mainly dominated by $S_7^{4\text{-}1}$ fluid production. After CO_2 injection, the profile mobilization was more uniform than water flooding and the degree of mobilization increased from 76.9% to 100% in the water flooding stage, with a large variation in the later stage due to reservoir inhomogeneity.

4.2.3 Rapid Recovery of Formation Pressure after CO_2 Injection

The average formation pressure of production wells before injection test is 17.67 MPa. After 45 days of CO_2 injection, the average formation pressure of single well is 25.67 MPa, and the average formation pressure of production wells tested in the first half of 2018 is 23.54 MPa, which is higher than the average formation pressure before trial injection, as shown in Fig. 10. At the same time, from the perspective of wellhead oil pressure, in the 10 oil production wells, the oil pressure rises rapidly in 4 wells, rises slowly in 2 wells, remains stable in 2 wells and fluctuates in 2 wells. Among them, the oil wells in well group 80513 are mainly rising rapidly, while the pressure of oil wells in well group 80534 varies greatly.

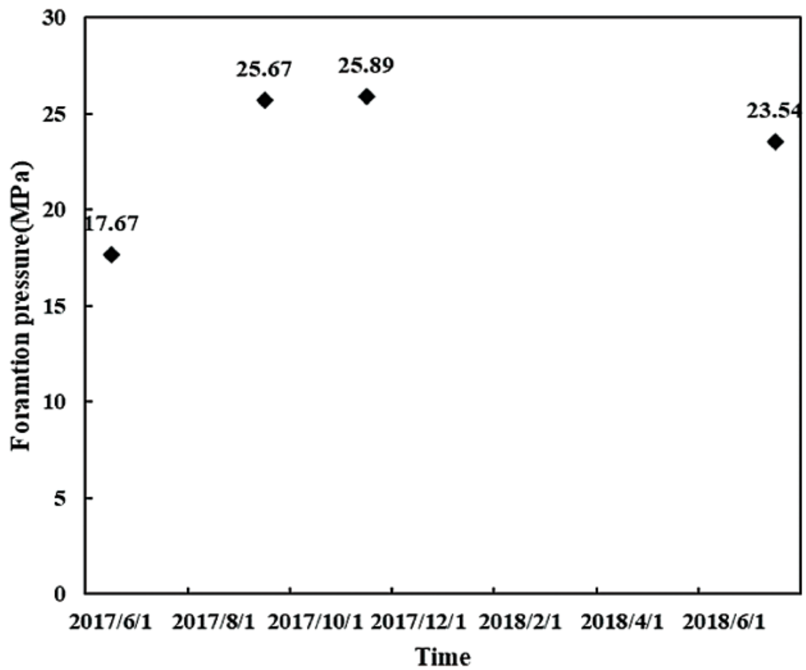


Figure 10: Formation pressure variation curve in well 80492

4.2.4 The Daily oil Production after CO_2 Injection is Significantly Higher Than That in Water Flooding Stage

Only 4 of the 10 oil wells in the well group before CO_2 test injection adopt the mode of interleaved production. After the test injection, 9 oil wells are opened for production, and 5 wells have good results, with an efficiency of 50%, as shown in Table 5.

Table 5: Comparison of production before and after injection of well group 80513 and 80534

Number	Pre-test injection			First month of test mining			Currently				Whether effective
	Daily liquid production (t)	Daily oil production (t)	Water cut (%)	Daily liquid production (t)	Daily oil production (t)	Water cut (%)	Daily liquid production (t)	Daily oil production (t)	Water cut (%)	Cumulative oil production (t)	
80532	Low energy shutdown			1.5	0.2	86.7	Low energy shutdown			86	No
80514	Low energy does not come out			Airlock			4.11	1.09	73.48	235	Yes
80512	Low energy shutdown			10.3	4.6	55.3	7.29	2.01	72.43	1203	Yes
80206	1.7	0.6	66.7	3.5	0.5	85.2	1.92	0.48	75.00	54	Deny
80492	3.8	0.5	87.8	16.3	3.9	75.9	7.13	2.71	61.99	576	Yes
80555	Low energy shutdown			3.7	1.4	62.5	Low energy shutdown			234	Yes
80533	2.3	0.84	62.8	2.9	1.0	66.4	Low energy shutdown			212	Yes
80515	2	0.88	56.9	2.5	0.9	64.8	Low energy shutdown			132	No
80535	Low energy shutdown			0.4	0.01	97.5	4.67	0	99	4	No

(Continued)

Table 5 (continued)

Number	Pre-test injection			First month of test mining			Currently				Whether effective
	Daily liquid produc-tion (t)	Daily oil produc-tion (t)	Water cut (%)	Daily liquid produc-tion (t)	Daily oil produc-tion (t)	Water cut (%)	Daily liquid produc-tion (t)	Daily oil produc-tion (t)	Water cut (%)	Cumulative oil pro-duction (t)	
80556	Low energy shutdown			2.8	0.1	95.2	3.57	0	99	5	No
Average	2.1	0.6	71.4	4.9	1.4	71.4	4.78	1.05	80.15	2741	-

Through the analysis of field injection effect, it can be seen that the factors affecting the development effect of CO_2 flooding are complicated, and not all oil Wells can be effective. The effectiveness of oil well is closely related to formation physical properties, inter-well connectivity, water content, etc. It is necessary to carry out a fine anatomy in the next step and optimize gas injection parameters, so as to further improve CO_2 flooding development effect of conglomerate reservoir.

5 Summary and Conclusions

(1) Through the evaluation of the production dynamics and remaining oil in the test area, the residual oil saturation is high, indicating that the test area has a large residual oil potential.

(2) The minimum CO_2/crude oil miscible pressure was determined to be 24.1 MPa by fine tube experiments.

(3) The experimental results of CO_2 aerated expansion showed that the saturation pressure of formation crude oil increased significantly after the injection of CO_2, and the more CO_2 was injected, the higher the saturation pressure was. When the content of injected CO_2 in formation crude oil was 55.29 mol%, the saturation pressure of CO_2-formation crude oil system reached 31.60 MPa.

(4) Two-dimensional planar visualization model experiments show that the remaining oil after water flooding mainly exists in the form of clusters, membranes, columns and blind ends, and some remaining oil after gas flooding still exists in the form of islands, clusters and membranes and there is obvious gravity overtopping phenomenon. By carrying out CO_2 flooding on the basis of water flooding, the wave efficiency is significantly improved. The analysis of the field trial injection effect shows that: the single well CO_2 absorption capacity is significantly increased compared with the water absorption capacity; the profile activation degree in the gas injection stage is better than that in the water flooding stage; the CO_2 injection restores the formation pressure quickly; the oil production after gas injection in the trial recovery effect is significantly increased compared with that in the water flooding stage.

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Conflicts of Interest: The authors declare that they have no conflicts of interest to report regarding the present study.

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