



# Evaluation of Carbon Dioxide Flooding in Reservoir of Extra Low Permeability— Case Study in Wangyao Chang6 Reservoir of Ansai Oil-Field

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**Abstract.** The Triassic Chang6 extra-low permeability reservoir in Ansai Oilfield has entered the period of medium to high water cut, and the contradiction of water flooding development is increasingly prominent. The single water flooding development has limited space to improve the output of a single well, and CO<sub>2</sub> can reduce the interfacial tension and capillary resistance between the injected medium and the formation crude oil, thus effectively improving the oil displacement efficiency. For a good quality of the oil in Ansai Oilfield, the characteristics of the reservoir structure stability, to explore a new mode to enhance oil recovery of CO<sub>2</sub> and has conducted the related evaluation and numerical simulation of indoor carbon dioxide scheme optimization, The suitable CO<sub>2</sub> injection process and reasonable injection parameters were optimized. On the basis of the experimental area of CO<sub>2</sub> injection, forecast the oil displacement effect of water alternating injection method is higher than pure gas displacement amplitude increase recovery efficiency, The increase of slug quantity prolongs the breakthrough time of CO<sub>2</sub>. The identified alternative development scheme for carbon dioxide flooding can improve recovery by more than 10% compared with water flooding.

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**Keywords:** Ansai Oil-field · Extra low permeability · Carbon dioxide flooding · Enhanced oil recovery

## 1 Introduction

Carbon dioxide injection to improve oil recovery has been paid much attention due to its unique properties. In recent years, many scholars have conducted relevant studies on using carbon dioxide to improve oil recovery and geological storage, and have made certain achievements and understandings [1–5]. Due to low CO<sub>2</sub> injection pressure, large injection capacity, fast pressure conduction, and easy to dissolve in crude oil, the viscosity of crude oil is greatly reduced, thus improving oil displacement efficiency [6–10]. In addition, a large amount of CO<sub>2</sub> can be obtained from the by-products of chemical industry or power plants, which also have environmental value [11–13]. The feasibility of carbon dioxide flooding in chang 6 reservoir of wangyao district of Ansai Oilfield was studied by laboratory study and numerical simulation, and the scheme was optimized and forecasted, providing some reference for field test.

## 2 Basic Information

The study area is located in the west of Ansai Oilfield and is structurally located in the middle of Shanbei Slope. The main producing layers is chang 6, and the sedimentary microfacies are dominated by the delta leading edge estuary dam and estuarine dam - underwater distributary channel deposition. The channel deposition scale in chang 6<sub>1-2</sub> period reaches the maximum, and the multi-stage channel sedimentary sand bodies are superposed and joined together. In chang 6<sub>1-1</sub> period, the channel deposition scale decreases. The buried depth is 1100–1300 m, and the average effective thickness of the reservoir is 13.3 m. The lithology is fine - grained hard arkose with good grain separation, high structural maturity and low mineral maturity. The total cementing content of chang6 reservoir is 14.78%, among which calcite is 0.14%, Water mica is 0.57%, chlorite is 5.28%, ferrodolomite and ferrocalcite are 0.91%, and laumontite is 2.56%. Due to strong diagenesis, the pore structure is complex, mainly small pore throat, the throat radius is 0.15–0.35 μm, the separation coefficient is 2.4, the pore volume connected by throat below 0.1 μm accounts for 40%, the pore volume connected by throat above 0.81 μm accounts for 22%. The reservoir has poor physical properties, with average effective porosity of 11%–15%, permeability of  $1 \times 10^{-3}$ – $3 \times 10^{-3}$  μm<sup>2</sup>, basically bottomless water, average original oil saturation of 55.6%, original formation pressure of chang6 reservoir in wangyao district of 9.13 MPa, pressure coefficient of 0.7, which is a typical ultra-low permeability reservoir.

As of the end of December 2018, the water driving and control rates are 76.7% and 92.6% respectively. The comprehensive water content is 70.5%, and the recovery

degree is 18.87%. At present, the formation pressure is 10.7 MPa, maintaining the level of 111.49% of the original formation pressure, and the plane distribution is relatively balanced.

### 3 Fluid Properties and Fitting

Chang 6 fluid in ansai oilfield has good properties, density of crude oil is 0.84–0.85 g/cm<sup>3</sup>, viscosity 4.8–7 MPa S. freezing point 19–22 °C, The saturation pressure of crude oil is 4.65–6.79 MPa, the gas-oil ratio is 54–79 m<sup>3</sup>/t, and the volume coefficient is 1.15–1.21. The average molecular weight of crude oil obtained from the original gas component and original oil component provided by the oilfield is 164.7885. The original gas-oil ratio in this area was 79.1 m<sup>3</sup>/t, and the density of degassed crude oil was 0.8403 g/cm<sup>3</sup>, as per the standard. The volume of 1 mol gas in the quasi-state is 22.4 L, and the fluid composition and content of chang6 wangyao reservoir can be calculated (see Table 1).

**Table 1.** Fluid composition and content in chang6 wangyao reservoir

Component	Mole fraction (%)	Component	Mole fraction (%)	Component	Mole fraction (%)
N <sub>2</sub>	0.97	C <sub>11</sub>	1.7	C <sub>23</sub>	0.95
CO <sub>2</sub>	0.07	C <sub>12</sub>	1.47	C <sub>24</sub>	0.85
C <sub>1</sub>	22.08	C <sub>13</sub>	1.31	C <sub>25</sub>	0.87
C <sub>2</sub>	5.7	C <sub>14</sub>	1.15	C <sub>26</sub>	0.94
C <sub>3</sub>	11.99	C <sub>15</sub>	0.9	C <sub>27</sub>	1.37
C <sub>4</sub>	10.76	C <sub>16</sub>	0.92	C <sub>28</sub>	1.57
C <sub>5</sub>	7.58	C <sub>17</sub>	1.22	C <sub>29</sub>	1.71
C <sub>6</sub>	4.94	C <sub>18</sub>	1.15	C <sub>30</sub>	1.14
C <sub>7</sub>	3.75	C <sub>19</sub>	1.09	C <sub>31</sub>	0.72
C <sub>8</sub>	2.83	C <sub>20</sub>	1.12	C <sub>32</sub>	0.39
C <sub>9</sub>	2.24	C <sub>21</sub>	1.17	C <sub>33</sub>	0.25
C <sub>10</sub>	2.05	C <sub>22</sub>	1	C <sub>34+</sub>	0.11
				Sum	100

Through fitting the bubble point pressure, dissolved gas-oil ratio, crude oil viscosity and volume coefficient of the fluid in wangyao chang6 reservoir, the pseudo-components that conform to the characteristics of the fluid phase state of the reservoir are obtained, and the parameters of the equation of state are obtained (Table 2).

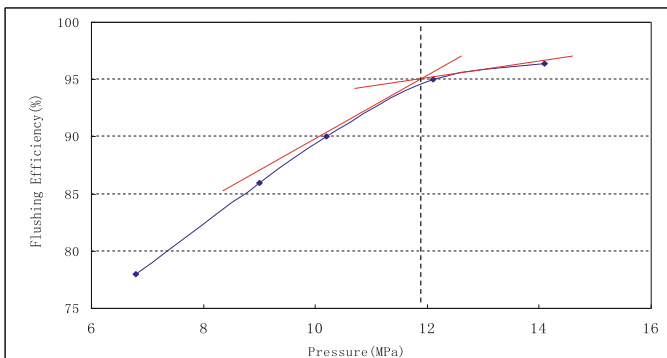
**Table 2.** Critical characteristic parameters of quasi-component fluid in chang6 wangyao reservoir

Component	Mole fraction	Critical pressure (bar)	Critical temperature (K)	Omega A	Omega B	Acentric factor	Parachor	Critical volume	Critical Z factor
N <sub>2</sub>	28.01	33.94	126.2	0.457	0.078	0.04	41	0.09	0.29
CO <sub>2</sub>	44.01	73.87	304.7	0.457	0.078	0.23	78	0.09	0.27
C <sub>1</sub>	16.04	46.04	190.6	0.457	0.078	0.01	77	0.1	0.28
C <sub>2</sub>	30.07	48.84	305.43	0.457	0.078	0.1	108	0.15	0.28
C <sub>3</sub>	44.1	42.46	369.8	0.595	0.078	0.15	150.3	0.2	0.27
C <sub>4</sub>	58.12	37.47	419.5	0.671	0.078	0.2	187.2	0.26	0.28
C <sub>5</sub>	72.15	33.59	465.9	0.686	0.078	0.24	228.9	0.31	0.29
C <sub>6</sub>	84	30.1	507.5	0.686	0.078	0.3	271	0.35	0.25
C <sub>7+</sub>	236.74	18.68	726.44	0.229	0.063	0.59	620.69	0.85	0.26

### 4 Minimum Miscible Pressure Test

Thin pipe simulation is a one-dimensional model formed by simplifying the reservoir to the maximum extent. Its function is to provide a continuous contact environment for the oil and injected gas in the porous medium, and to eliminate the influence of unfavorable mobility ratio, viscous fingering, gravity separation, lithological heterogeneity and other factors as far as possible. The minimum miscible pressure obtained can represent the measured oil and gas system. According to the actual gas-oil ratio, the formation oil was allocated. After the 1.2pv injected gas (volume under injection pressure) was injected into the thin tube experiment, the displacement was stopped, and the minimum miscible pressure of CO<sub>2</sub> injection in this area was 11.8 MPa (Fig. 1).

The mechanism model was established based on the average physical parameters of the wangyao experimental area, and the oil displacement efficiency of CO<sub>2</sub> injection was calculated by numerical simulation method. The minimum miscible pressure of CO<sub>2</sub> flooding in this area was predicted to be 12 MPa, with an error of 1.69% compared with the experimental results.



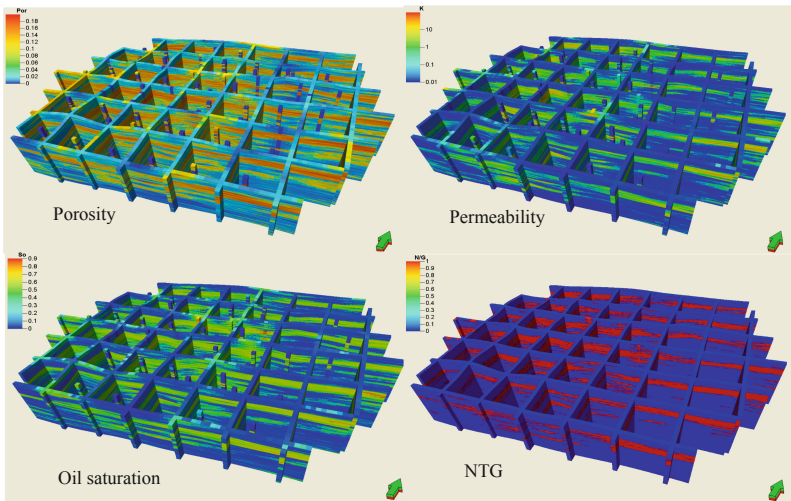
**Fig. 1.** Miscible pressure diagram of carbon dioxide injection in thin tube experiment in Ansai Oilfield

At present, the average formation pressure in the study area is less than the minimum miscibility pressure, and the condition of miscibility cannot be reached.

## 5 History Matching

The research area is located in the west of wangyao area, with an area of 4.22 km<sup>2</sup>. There are 50 production wells and 19 injection wells. The well pattern in the gas injection test area is based on the primary well pattern. There are 5 gas injection wells (W20-08, W22-05, W20-06, W21-05, W22-03) and 32 oil Wells. The injection well pattern around the test area is complete.

Based on the interpretation of well logging parameters, a three-dimensional geological model was established by comparing five small layers of chang 6 reservoir with the random modeling method. The angular point grid of 30 m × 30 m × 0.5 m was used to build the model grid of chang6 reservoir in wangyao research area: 98 × 69 × 232 = 1,568,784. The main layer is chang6<sub>1</sub><sup>1-2</sup> sand body with continuous development, good connectivity and poor other layers. After coarsening, the basic grid step length of chang6 reservoir is 30 m × 30 m, which is vertically coarsened into 9 small layers according to the development layer system (see Fig. 2). The numerical simulation model of chang 6 reservoir is divided into 87 units in plane I direction, 67 units in J direction, and 9 units in Z direction. The total number of grids is 87 67 9 = 52461.



**Fig. 2.** Grid diagram of the attribute model in the research area

After adjustment, the geological reserves of the modeling area are  $265.3 \times 10^4$  t, of which the experimental area is  $83.4 \times 10^4$  t, accounting for 31.43% of the geological reserves of the modeling area.

In order to achieve the fitting of formation pressure, fluid production and water cut, as well as oil production, liquid production and water cut of a single well, the uncertain factors, such as phase permeability, local permeability, directional permeability and conductivity, were modified in the fitting process, and the fitting effect was good. The fitting coincidence rate of a single well was over 90%.

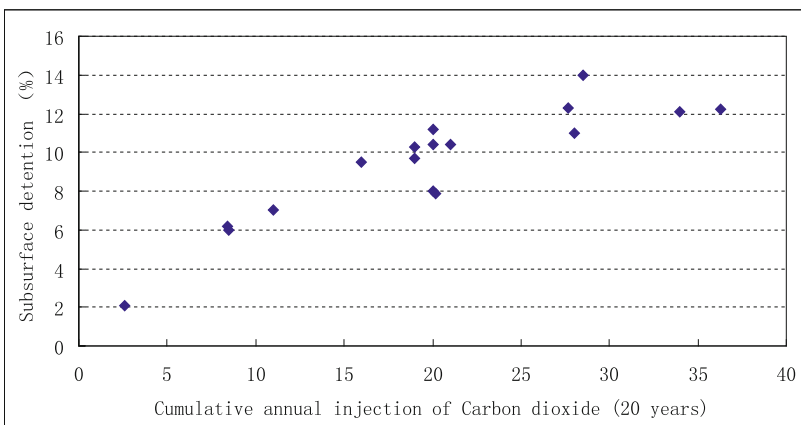
## 6 Program Optimization and Prediction

Application of reservoir numerical simulation method, the research block component model is established, through the design of different CO<sub>2</sub> displacement solution, optimized to determine the total injection volume, formation pressure, level, production speed, shut-in gas oil ratio, water alternating process parameters such as frequency and time, get the best gas injection process parameters of CO<sub>2</sub> flooding, provide the basis for the scheme in the CO<sub>2</sub> flooding to improve oil recovery technology. Where, the 20-year oil increment is the difference between the accumulative oil production in the 20-year stage of each scheme and that in the 20-year stage of water injection scheme.

### 6.1 Total Gas Injection

Retention volume of CO<sub>2</sub> in formation is proportional to sweep volume. The larger the CO<sub>2</sub> sweep volume, the higher the CO<sub>2</sub> retention, and the larger the enhanced recovery rate (compared with water injection), Adequate gas injection is the key to increase sweep volume. CO<sub>2</sub> sweep volume is mainly affected by cumulative gas injection.

When the cumulative gas injection volume is higher than  $20 \times 10^4$  t, the sweep volume increases slowly (see Fig. 3), and other parameters had little influence on the retention volume. The reason is that the ultimate swept volume is mainly affected by reservoir heterogeneity, well spacing, fracturing system and oil-gas flow ratio.



**Fig. 3.** Relationship between CO<sub>2</sub> injection amount and retention amount under different injection amount schemes

The recommended reasonable total gas injection volume: under the current well pattern condition, the reasonable total gas injection volume of the target layer is  $20 \times 10^4$ – $25 \times 10^4$  t. Add 10%–20% on this basis, taking into account the interlayer suction.

## 6.2 Formation Pressure

According to the simulation results under different formation pressures, high formation pressure has the following advantages: miscible flooding range is larger, recoverable reserves increase more; High production pressure difference and high oil recovery speed. Disadvantages of high formation pressure: large gas injection; Formation pressure is higher than 15 MPa, and due to the low viscosity of the gas, there is an increased risk of sudden gas flow due to the communication between natural and artificial fractures. A reasonable pressure level of 12–13 MPa is recommended.

## 6.3 Oil Recovery Rate

In order to study the influence of oil recovery rate on the effect of water injection and gas injection, the following four contrast schemes are designed:

- (1) water injection development, daily oil production of 54 m<sup>3</sup>/d in the test area;
- (2) water injection development, daily oil production of 78 m<sup>3</sup>/d in the test area
- (3) gas injection development, daily oil production of 54 m<sup>3</sup>/d in test area;
- (4) gas injection development, daily oil production of 78 m<sup>3</sup>/d in test area.

During waterflood development, after the daily production of oil in the test area increased from 54 m<sup>3</sup>/d to 78 m<sup>3</sup>/d, the formation pressure was difficult to be stable, and the recovery degree increased by 2.04%. With the alternation of water and gas, after the daily production of oil in the test area increased from 54 m<sup>3</sup>/d to 78 m<sup>3</sup>/d, the formation pressure was stable and the recovery degree increased by 16.41%.

Under the condition of maintaining formation pressure and ensuring sufficient gas injection, the higher the oil recovery rate is, the higher the degree of oil recovery is in the 20-year stage. However, excessively high oil recovery rate will lead to a rapid rise in gas-oil ratio and a substantial increase in the total gas injection required. From the comprehensive consideration of recovery degree, total gas injection and oil exchange rate, the test area produces 78 m<sup>3</sup>/d oil per day with the best development effect. Due to the effect of miscible flooding to increase recoverable reserves, compared with the scheme of water injection foundation, after the increase of oil recovery speed, the degree of water-gas alternation mode increased greatly, while the degree of water injection development increased little.

## 6.4 Shut-in Gas-Oil Ratio

In order to obtain reasonable shut-in gas-oil ratio in the research block, four WAG (6:6) displacement schemes with shut-in gas-oil ratio of 500 m<sup>3</sup>/m<sup>3</sup>, 1000 m<sup>3</sup>/m<sup>3</sup>, 3000 m<sup>3</sup>/m<sup>3</sup> and 5000 m<sup>3</sup>/m<sup>3</sup> were designed respectively.

When the formation pressure remains around 13 MPa, the influence of shut-in gas-oil ratio on the development effect is calculated by comparison (see Table 3): as the formation pressure shut-in gas-oil ratio increases, the degree of production increases slightly, but the total gas injection increases greatly, and the gas injection utilization rate decreases and the oil exchange rate decreases. However, too low shut-in gas-oil ratio will lead to early shut-in of production Wells, decline of production speed and decline of production degree within the predicted time. Considering the production degree, total gas injection and oil exchange rate in the test area, the shut-in gas-oil ratio of 1000 m<sup>3</sup>/m<sup>3</sup> is more reasonable.

**Table 3.** Results of different shut-in gas-oil ratio simulation schemes

Alternate way	Formation pressure (MPa)	Oil production (m <sup>3</sup> /d)	Shut-in gas-oil ratio (m <sup>3</sup> /m <sup>3</sup> )	Recovery degree (%)	The total injection volume (10 <sup>4</sup> t)	Retention volume (10 <sup>4</sup> t)	Oil change rate (f)
WAG(6:6)	13	54	500	35	8.6	6.2	0.491
WAG(6:6)	13	54	1000	38.9	15.8	9.4	0.45
WAG(6:6)	13	54	3000	42.1	27.7	11	0.38
WAG(6:6)	13	54	5000	43.8	36.5	12.5	0.33

## 6.5 Alternation Time

Different alternation time of water and gas, that is, different size of water and gas slug, not only affect the control of gasoline ratio, but also directly affect the degree of difficulty of mine operation. The displacement simulation experiments of WAG(1:1), WAG(3:3) and WAG(6:6) with the same total injection amount were designed. This indicates that the more the number of alternate slugs is, the better the gas-oil ratio control will be. The effect may be more pronounced at low shut-in gas-oil ratios (Table 4).

By comparing the development indexes of 18 WAG schemes, the influence degree of each gas injection process parameter on the development effect is analyzed. The research shows that the influence degree of each factor on the development effect of WAG is ranked as:

A. Total gas injection; B. Formation pressure; C. Oil recovery rate; D. Shut-in gas-oil ratio; E. alternation time of water and air. The results of gas injection parameters in the WPZ under current well pattern conditions can be obtained:

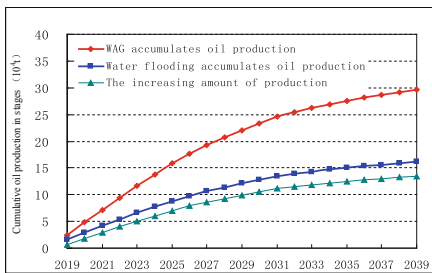
- (1) Formation pressure: 12–13 MPa;
- (2) Total gas injection:  $20 \times 10^4$ – $25 \times 10^4$  t (20 years);
- (3) Speed up production: daily oil production is 78 m<sup>3</sup>/d (65 t/d);
- (4) Shut-in gas-oil ratio: 1000 m<sup>3</sup>/m<sup>3</sup>; Cycle of alternation of water and gas; 1 month water injection, 1 month gas injection.
- (5) Water and gas alternation time: water and gas injection ratio is 1:1.



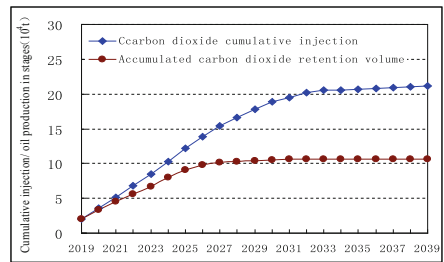
**Table 4.** Development index prediction of 18 WAG flooding schemes in CO<sub>2</sub> test area

Alternate node (W/G)	Formation pressure (MPa)	Oil production rate (m <sup>3</sup> /d)	Gas-oil ratio m <sup>3</sup> /m <sup>3</sup>	Stage production/injection (20 years)					Recovery ratio (%)	Recovery increment (%)
				Water injection (10 <sup>4</sup> m <sup>3</sup> )	CO <sub>2</sub> injection (10 <sup>4</sup> t <sup>3</sup> )	Oil producing (10 <sup>4</sup> t <sup>3</sup> )	Water producing (10 <sup>4</sup> m <sup>3</sup> )	Oil increment (10 <sup>4</sup> t)		
6:6	13.0	54.0	1000	206.0	15.8	34.9	159.4	7.1	38.9	10.3
6:6	13.0	78.0	1000	211.4	21.2	40.8	158.9	13.0	45.0	16.4
6:6	13.0	78.0	3000	232.6	34	43.9	178.1	16.1	48.3	19.8
6:6	13.0	54.0	500	187.5	8.6	32.0	141.0	4.2	35.0	6.4
6:6	13.0	54.0	3000	227.2	27.7	38.3	177.1	10.6	42.1	13.5
6:6	13.0	54.0	5000	230.7	36.5	39.7	181.0	11.9	43.8	15.2
6:6	15.0	97.0	1000	205.4	28.7	42.2	150.7	14.4	48.1	19.5
6:6	10.5	54.0	1000	210.8	2.8	28.7	167.7	1.0	29.6	1.0
6:6	13.0	54.0	1000	211.9	27	42.7	161	14.9	45.1	16.6
9:3	13.0	54.0	1000	202.8	8.8	31.4	164	3.7	34.9	6.4
8:4	13.0	54.0	1000	196.5	10.7	32.0	157.6	4.3	36.1	7.6
4:8	13.0	54.0	1000	198.0	19.3	36.6	149.4	8.9	40.1	11.5
3:9	13.0	54.0	1000	193.6	19.2	36.1	146.1	8.4	39.2	10.6
6:6	13.0	54.0	1000	178.5	20	34.9	139.8	7.2	39.5	11.0
6:6	13.0	54.0	3000	235.5	20	35.0	188.4	7.3	37.0	8.5
1:1	13.0	54.0	3000	242.5	20.3	34.9	196.3	7.2	36.8	8.3
3:3	12.8–11.3	54.0	3000	244.9	20.1	35.0	198.0	7.2	36.8	8.2
3:3	12.6–11.3	54.0	1000	237.1	20.1	36.5	187.7	8.8	39.1	10.5

The prediction of stimulation effect of the recommended scheme shows that the cumulative oil increase of  $13.5 \times 10^4$  t over 20 years can be obtained by WAG CO<sub>2</sub> injection compared with water injection (Fig. 4). After 10 years of gas injection, due to the large number of shut-in Wells and the slow increase of cumulative oil increase, gas injection can be stopped and water injection can be transferred to development. Cumulative CO<sub>2</sub> injection for 20 years totaled  $21.1 \times 10^4$  t, and cumulative CO<sub>2</sub> retention was  $10.6 \times 10^4$  t, with a cumulative retention rate of about 0.5 (see Fig. 5).



**Fig. 4.** Comparison curves of oil increase in different displacement modes



**Fig. 5.** Curve of cumulative injection and retention of CO<sub>2</sub> flooding

## 7 Conclusion

1. According to the laboratory fine tube test and numerical simulation, the minimum miscible pressure of wangyao CO<sub>2</sub> flooding is about 12 MPa. At present, the formation pressure of main strata in this area is 10.7 MPa, which is close to the minimum miscible pressure.
2. In order to supplement the formation energy and increase the formation pressure to achieve miscibility flooding as soon as possible, a large injection amount is needed to increase the formation pressure to 12–13 MPa to achieve miscibility.
3. Optimization results of gas injection parameters in the current well pattern condition gas injection test area in wangyao district of Ansai Oilfield: The total injection volume; Formation pressure; Production speed; Shut-in gas-oil ratio; Ater and gas alternation time.
4. The method of alternate injection of water and gas improves the recovery rate by a higher margin than the simple gas flooding, and increasing the number of slugs is conducive to extending the breakthrough time of carbon dioxide. The CO<sub>2</sub> flooding development program determined after optimization of gas injection parameters can improve oil recovery by more than 15% compared with water flooding, and the cumulative oil increase is  $13.5 \times 10^4$  t in 20 years in the study area.

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