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Application of CO_2 Immiscible Flooding Technology of Low-permeability Oil Fields in Northern Songliao Basin (ICCUSC2024)

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ABSTRACT

The oil reservoir in the peripheral oil fields of northern Songliao Basin is characterized by low permeability and complex structures. With the decreasing oil production, there is an urgent need to change the injection and production methods. Laboratory experiments is performed in order to study the application of CO_2 displacement technology. The results of laboratory experimental studies shows that CO_2 injection can significantly increase the fluidity of crude oil through dissolution, viscosity reduction, and gas-injection expansion. It indicates that CO_2 has good dissolution, viscosity reduction, and gas injection expansion effects, which can significantly increase the fluidity of crude oil. Based on the characteristics of the reservoir, it is believed that the low-permeability reservoir around northern Songliao Basin is suitable for CO_2 flooding. CO_2/water alternating injection increases oil recovery by 28.13 percentage points compared to water flooding.Production parameters are optimized by numerical simulation, the results show that the higher the level of formation pressure recovery, the better CO_2 flooding effect. The optimization result is to use a gas to water ratio of 3:1, with a water gas alternation cycle of 2 months of water injection and 2 months of gas injection.This method can increase oil recovery by 11 percentage points compared to water flooding,utilizing remaining oil effectively. The research has reference significance for CO_2 immiscible flooding in other low-permeability reservoirs.

Keywords:low permeability; CO_2 flooding;enhanced oil recovery; parameter optimization

1. INTRODUCTION

For an extended period in the future, oil and gas will remain irreplaceable in primary energy consumption. Petroleum companies must not only maintain stable crude oil production but also embark on the path of green and low-carbon development transformation [1]. Injecting CO_2 into the ground to enhance oil recovery (EOR) is an effective approach to achieving this dual objective. The Soviet Union pioneered the research on CO_2 EOR technology as early as 1952, with trials yielding notable improvements in development effectiveness, boosting crude oil recovery rates by an additional 15 percentage points compared to previous methods [2]. The United States leads the world in the application, experience, and technological maturity of CO_2 EOR, being the first nation to both research and implement CO_2-enhanced oil recovery (CO_2-EOR) techniques[3]. American CO_2 injection projects predominantly involve marine deposits, with 90% capable of achieving miscible flooding. These reservoirs exhibit relatively homogeneous properties, leading to superior oil displacement outcomes [4].In contrast, China's venture into CO_2 injection for EOR started later, initiating theoretical studies in the 1960s and conducting field trials at locations such as Shengli Oilfield and Jilin Oilfield [5]. While the country has made some strides in CO_2 EOR technology, the focus has largely been on CO_2 immiscible flooding, which remains in the pilot testing phase. Consequently, the resulting increments in recovery rates are relatively low, generally less than 5 percentage points [6]. In the northern Songliao Basin, oilfields are characterized by low porosity and permeability. Pilot tests conducted there have shown insignificant improvements in sweep efficiency post CO_2 injection, with ambiguous signs of effectiveness and limited production increases. Given the distinct reservoir characteristics, conventional control techniques prove inadequate for the low-permeability reservoirs in the region. Thus, there is an urgent need to develop CO_2 immiscible flooding technologies tailored to these challenging low-permeability oil reservoirs.

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2. GEOLOGICAL CHARACTERISTICS AND DEVELOPMENT INTRODUCTION

2.1 Reservoir and fluid characteristics

The reservoir extends from the northern Grape Flower structure to the south, dipping to form the nasal structure. This structure continues to develop southward, forming a north-south uplift zone defined by the -1150m structural line. The top surface has an elevation depth range of -1020m to -1100m, with a dip angle of 1° to 3° within the fault block. Overall, it exhibits a characteristic of higher elevation in the west and lower elevation in the east. The faults are well developed, with low-angle normal faults, generally dipping at an angle of 40° to 50°. The faults are intersecting and widely distributed, making the structure complex. The overlying layer is a thick layer of lacustrine sedimentary mudstone, with a thickness greater than 600m and good sealing capability. The main controlling fault cuts through the overlying layer, forming a Y-shaped profile with good vertical sealing capability and low leakage risk. The reservoir consists of hard, sandy feldspathic coarse-grained sandstone. The rock fragments include quartz and feldspar, with acidic volcanic rocks as the main component. The average porosity is 18.7%, and the average permeability is 40.9mD, indicating a low-porosity and low-permeability reservoir. The density of the crude oil at the surface is 0.8539g/cm3, and the viscosity is 14.1mPa.s. The chloride ion content in the formation water averages 4065.8mg/L, with an average salinity of 11430mg/L, indicating a NaHCO3-type water. The average formation depth is 1304m, the average formation temperature is 57.9°C, and the average geothermal gradient is 4.82°C/100m, indicating a relatively high geothermal gradient reservoir.

2.2 Development Overview

The test area was put into development in 1995. Initially, a reverse nine-spot water injection development method was used for the well pattern. The average daily liquid production per well was 1.9t/d, with an average daily oil production per well of 1.9t/d, excluding water. In 2006, the well pattern was expanded using a reverse nine-spot method. In 2017, the injection and production system was adjusted, transitioning to a linear water injection development method. As of June 2023, there is an average daily oil production per well of 0.6 t, with a comprehensive water cut of 81.9%. The oil production rate in the block is 0.48%, and the recovery factor is 23.46%, with a cumulative injection-production ratio of 2.09. The overall production in the test area has been declining year by year, with high water cut and low recovery factor. It is urgent to change the development method, improve development efficiency, and increase the recovery rate.

3. LABORATORY EXPERIMENTS

3.1 Properties of Formation Crude Oil

Selecting crude oil from the experimental area for total hydrocarbon chromatography analysis, the results are shown in Table 1. The natural gas samples were subjected to natural gas composition analysis, and the results of the degassed crude oil components are shown in figure 1. Through experiments, it was found that the density of formation crude oil is 0.7798g/m3, the density of degassed crude oil is 0.8376g/m3, the viscosity of formation crude oil is 2.98mPa. s, the gas oil ratio for single degassing is 33.8m3/m3, and the volume coefficient of formation crude oil is 1.119.

3.2 CO_2 Expansion Experiment

Studying the phase changes of crude oil systems through CO_2 expansion experiments is an important basis for studying oil displacement mechanisms and can

Fig. 1 Distribution of degassed crude oil components in the experimental area

Table.1 Analysis Results of Natural Gas Components

Component	CO_2	N_2	C_1	C_2	C_3	iC_4	nC_4	iC_5	nC_5	Total
Molar Composition（%）	0.48	1.4	75.69	7.28	6.03	2.42	3.68	1.52	1.5	100

Table 2. Results of Formation Crude Oil Gas Injection Expansion Experiment

Gas injection times	injection gas mole fraction(%)	gas oil ratio (m^3/m^3)	Volume coefficient	bubble point pressure (MPa)	density (g/cm^3)	viscosity (mPa•s)	Expansion coefficient
0	0	33.80	1.1189	7.39	0.7798	2.98	1
1	5.4	42.42	1.1362	8.24	0.7784	2.82	1.01
2	15.12	54.09	1.1670	9.27	0.7766	2.583	1.03
3	26.32	65.55	1.1988	10.24	0.7746	2.255	1.05
4	37.04	78.53	1.2275	11.36	0.7727	1.94	1.08
5	47.76	89.10	1.2574	12.09	0.77086	1.69	1.10
6	71.33	115.50	1.33	14.20	0.76716	1.27	1.15

also lay the foundation for writing development plans.[7] In order to study the changes in formation fluid parameters under different CO_2 injection conditions, gas injection expansion experiments were conducted. The experimental results are shown in Table 2. The experimental results show that as the amount of CO_2 injection increases, the gas oil ratio, saturation pressure, volume coefficient, and expansion coefficient increase, while viscosity and density decrease. CO_2 injection for oil recovery has good dissolution, viscosity reduction, and gas expansion effects, which can significantly increase the fluidity of crude oil.

4. NUMERICAL SIMULATION

4.1 Fluid Phase Behavior Fitting

The fitting of crude oil phase behavior is the basis for numerical simulation using a component model, directly affecting the accuracy and speed of the numerical simulation calculations.[8] For the convenience of numerical simulation calculations, the crude oil components were divided into 7 pseudo-components based on the principle of similar component properties. The relative errors of the main high-pressure physical parameters and the minimum miscibility pressure predicted by the component model for the formation crude oil are small, meeting the requirements of phase behavior simulation. Subsequently, gas injection expansion experiments and long core displacement experiment fitting were conducted, with a relative error of less than 1%, indicating good fitting results.

Table 3. Typical Oil Layer Fluid Phase Matching Parameters in the Experimental Area

parameter	Experimental value	Estimate value	Relative error(%)
Single degassing oil gas ratio(m^3/m^3)	33.8	34.35	1.64
Saturation pressure of formation crude oil (MPa)	7.39	7.38	0.08
Density of degassed crude oil(g/m^3)	0.84	0.83	0.61
Formation crude oil density(g/m^3)	0.78	0.79	1.03
Crude oil viscosity under formation pressure (mPa·s)	2.98	2.98	0
Volume coefficient under formation pressure (m^3/m^3)	1.12	1.11	0.69

4.2 Numerical Model Establishment

A multi-component numerical simulation model was established in the simulation area, with a grid number of 91 × 96 × 98 in the length,width and height directions. It was divided vertically into 18 layers. Based on the trajectory data, completion information, and measurement data of wells in the well area, a multi-component numerical simulation dynamic geological model of the Aonan Oilfield - Putaohua Oil Layer was established. The model's structural distribution, porosity, permeability, and oil saturation distribution are shown in Figure 2.

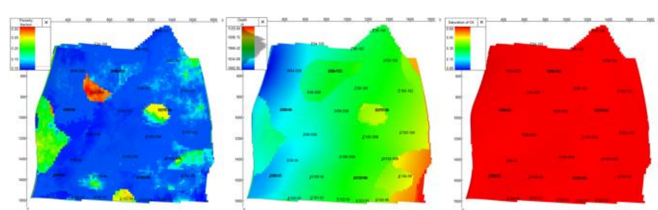

Fig. 2 Reservoir numerical simulation model

4.3 Block History Matching

In the simulation area, the cumulative oil production in February 2022 was 14.79 × 104t, and the simulated calculation value was 14.79 × 104t; The cumulative water production is 9.27 × 104m3, and the simulated calculation value was 9.27 × 104m3; The degree of crude oil extraction (actual production value) is 23.64%, and the simulated calculation value was 23.65%; The overall production history fit of the well area was good and successful(Figure 3).

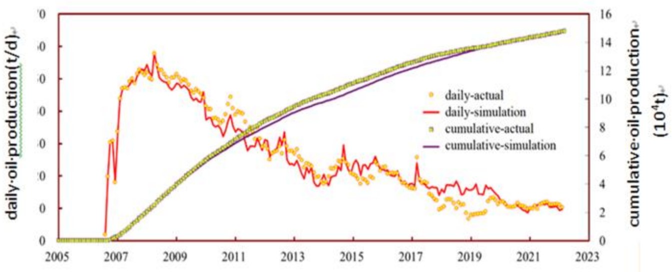

Fig.3 Simulation area production history matching

4.4 Optimization of Production Parameters and Scheme Design

Based on the historical fitting, the injection parameters were optimized. After the formation pressures reached 9MPa, 10MPa, 11MPa, and 12MPa respectively, gas injection begins. The development indicators under these conditions were predicted through numerical simulation (Table 4). The results showed that the higher the formation pressure recovery level, the higher the gas drive production. Therefore, all oil wells should shut down for pressure buildup during the initial stage of gas injection, and the wells should reopen when the formation pressure level recovered to over 80% .

Table 4. Prediction of Gas Drive Development Indicators at Different Pressure Levels

Formation pressure（MPa）	1st year			10th year			20th year		
	Daily oil production(t/d)	Gas oil ratio(m^3/m^3)	Accumulated oil production(10^4t)	Daily oil production(t/d)	Gas oil ratio(m^3/m^3)	Accumulated oil production(10^4t)	Daily oil production(t/d)	Gas oil ratio(m^3/m^3)	Accumulated oil production(10^4t)
9	1.4	32.3	33.7	17.9	169.5	43.1	10.4	399.9	52.0
10	1.4	32.3	32.1	19.2	248.5	43.7	10.7	405.7	53.0
11	1.4	32.3	33.3	17.1	191.5	45.5	9.4	478.8	54.0
12	1.4	32.3	32.7	19.2	255.6	48.0	10.1	601.8	55.1

The numerical simulation results showed that the larger the gas injection volume, the higher the initial oil production, but the gas oil ratio increased rapidly, resulting in a low oil replacement rate. Considering comprehensively, the initial annual gas injection volume was designed to be 0.12 HCPV. The numerical simulation results indicated that more frequent alternating cycles lead to better results. Considering the field operability, the water-gas alternating cycle was designed as 2 months of water injection and 2 months of gas injection. The numerical simulation showed that the larger the gas-water slug ratio, the higher the daily oil production, but the gas oil ratio also increased rapidly. Considering the pressure maintenance level, the rate of gas oil ratio increase, and the oil enhancement effect, the initial gas-water slug ratio was designed to be 3:1, gradually increasing the water slug and decreasing the gas slug as the gas oil ratio increased

5. CONCLUSION

(1)As the amount of CO_2 injection increases, the gas oil ratio, saturation pressure, volume coefficient, and expansion coefficient increase, while viscosity and density decrease.

(2)Advance gas injection is beneficial for pressure recovery, supplementing formation energy, and improving gas drive development efficiency.

(3)On the basis of production history fitting, production parameters were optimized through numerical simulation. The results indicate that a gas-water slug ratio of 3:1 and a water-gas alternation cycle of 2 months of water injection followed by 2 months of gas injection is suitable for the low-permeability reservoirs in the northern Songliao Basin. This approach can increase the recovery ratio by 11 percentage points compared to water drive, effectively utilizing the remaining oil.

DECLARATION OF INTEREST STATEMENT

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper. All authors read and approved the final manuscript.

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