Feasibility of Gas Drive in Fang-48 Fault Block Oil Reservoir

Cui Lining^{1,2}, Hou Jirui^{1,2} and Yin Xiangwen^{1,2}

(1. Key Laboratory of Petroleum Engineering under Ministry of Education, China University of Petroleum, Beijing 102249, China)

(2. Enhanced Oil Recovery Center, China University of Petroleum, Beijing 102249, China)

Abstract: The Fang-48 fault block oil reservoir is an extremely low permeability reservoir, and it is difficult to produce such a reservoir by waterflooding. Laboratory analysis of reservoir oil shows that the minimum miscibility pressure for CO₂ drive in Fang-48 fault block oil reservoir is 29 MPa, lower than the formation fracture pressure of 34 MPa, so the displacement mechanism is miscible drive. The threshold pressure gradient for gas injection is less than that for waterflooding, and the recovery by gas drive is higher than waterflooding. Furthermore, the threshold pressure gradient for carbon dioxide injection is smaller than that for hydrocarbon gas, and the oil recovery by carbon dioxide drive is higher than that by hydrocarbon gas displacement, so carbon dioxide drive is recommended for the development of the Fang-48 fault block oil reservoir.

Key words: Low permeability reservoir, gas drive, feasibility, laboratory analysis, numerical simulation

1. Introduction

Fang-48 fault block oil reservoir is located in the southeastern part of the Songfangtun reservoir, and is in the Zhaozhou structural nose, Sanzhao Sag in the northern part of the Songliao Basin. The parameters of this block are summarized as follows: Initial formation pressure 22.64 MPa, formation fracture pressure 34 MPa, formation oil density 0.8030 g/cm³, formation oil viscosity 3.3 mPa·s, porosity 14.5%, and permeability $1.4 \times 10^{-3} \mu\text{m}^2$.

Fang-48 fault block oil reservoir is an extremely low permeability reservoir, and it is difficult to produce such a reservoir by waterflooding. Gas drive is a mature method for enhancing oil recovery and field tests in some oilfields in China demonstrated that it is worthwhile to implement gas injection to improve the recovery of low permeability reservoirs. Accurate laboratory analysis of reservoir oil and numerical simulation were made in this work to study the feasibility of gas drive in the Fang-48 fault block oil reservoir.

2. Laboratory analysis of reservoir oil

Oil samples used in all tests were taken from Well 184-124 in the Songfangtun Oilfield and its viscosity was adjusted to 3.3 mPa·s, the initial reservoir oil viscosity. The gases added were CO₂, N₂ and natural gas. Table 1 lists the natural gas composition.

Table 1 Composition of natural gas

Component	N ₂	CO ₂	CH ₄	C ₂ H ₆	C ₃ H ₈	C ₄ H ₁₀	Total
Mole fraction %	0.54	1.43	92.11	3.58	1.93	0.41	100

2.1 Separator test and swelling test

A GF-731 high pressure/high temperature apparatus is capable of measuring physical properties of crude oil/natural gas systems, including viscosity, density, oil formation volume factor and vapor/liquid ratios under reservoir conditions, then the swelling capacity and gas-dissolving capacity of oil could be determined. The major components of GF-731 PVT apparatus include a phase behavior cell, high pressure dosing pump, thermostatic control system, pressure display and gas measuring system, high-pressure ball viscometer, capillary viscometer and electronic balance.

Separator test 1) Simulated formation oil was prepared in the PVT cell. 2) Some oil was separated from the PVT cell under reservoir conditions into a multistage gas/oil separator system to perform separator test. Separator test data are shown in Tables 2 and 3.

Table 2 Oil properties data

Pressure, MPa	Formation volume factor	Density, g/cm ³
22.64	1.0566	0.7657
20.48	1.0579	0.7648
18.31	1.0592	0.7638
16.15	1.0606	0.7628
13.98	1.0620	0.7618
11.82	1.0635	0.7608
9.66	1.0650	0.7597
7.49	1.0666	0.7585
6.55	1.0673	0.7580

Table 3 Variation in oil properties in the process of multistage separation

Pressure MPa	Viscosity mPa·s	GOR	Density g/cm ³	Formation volume factor
22.64	3.314	18	0.805	1.0538
5.20	2.859	18	0.784	1.0818
3.50	2.998	14	0.793	1.0665
1.70	3.211	7	0.801	1.0486
0.10	3.463	0	0.833	1.0383

Table 2 shows that the oil from the Fuyu Formation is heavy oil with a small formation volume factor. Oil formation volume factor varies slightly with pressure, in a range of 1.0566–1.0673. This indicates that there is limited energy of volumetric expansion in the Fang-48 fault block oil reservoir, thus elastic drive is not suitable.

Multistage separator tests (Table 3) indicate that the viscosity and density of crude oil increase with decreasing pressure, while the gas/oil ratio (GOR) and oil formation volume factor decrease (Table 3), indicating that the oil has moderate density, higher

viscosity, limited expandability and limited compressibility and the gas liberated from oil is characterized by low density.

Swelling test 1) The pressure in the PVT cell was increased above the bubble point pressure, and then gas was injected into the PVT cell. 2) After gas injection, the pressure in the PVT cell was increased to the formation pressure and then the physical properties of the gas-containing oil were measured; 3) Injection was continued and the above processes were repeated.

After injecting the gas produced from Well Fangshen-6, Well Shengqi-1-4 and carbon dioxide, the phase behavior data of oil/gas system are shown in Table 4. Experimental data indicate that the injected gases had evident influence on the physical properties of oils. The bubble point pressure, gas/oil ratio, formation volume factor and swell factor increased with increasing injection of gas, while the density and viscosity of oil/gas system decreased. This is helpful in enhancing oil recovery. However, the physical properties of oil cannot be changed by waterflooding, so gas drive is better than waterflooding in low permeability reservoirs.

Table 4 Influence of gas injected on oil physical properties

Injection gas	Mole of gas injected mol	Bubble point pressure p_b MPa	Density g/cm ³	Oil formation volume factor		GOR m ³ /m ³	Swell factor	Viscosity, mPa·s	
				p_b	40 MPa			p_b	40 MPa
Gas from Well Fangshen-6	0	5.2	0.8088	1.122	1.055	18	1	2.86	-
	0.040	6.4	0.8075	1.138	1.094	22	1.0125	2.50	3.78
	0.123	9.0	0.8041	1.167	1.108	31	1.0401	2.19	3.36
	0.245	13.3	0.7945	1.207	1.137	45	1.0758	1.95	2.60
	0.344	17.0	0.7828	1.252	1.170	60	1.1159	1.80	2.27
	0.429	22.5	0.7747	1.293	1.199	75	1.1524	1.82	2.08
Gas from Well Sheng-1-4	0	5.2	0.8088	1.122	1.055	18	1	2.86	-
	0.102	8.6	0.8031	1.142	1.105	27	1.0178	2.45	3.40
	0.187	12.0	0.7996	1.162	1.121	37	1.0357	2.27	3.10
	0.259	16.3	0.7910	1.185	1.142	46	1.0562	1.87	2.46
	0.325	20.5	0.7872	1.208	1.161	57	1.0769	1.89	2.28
	0.377	26.5	0.7809	1.232	1.183	70	1.0980	1.80	2.00
CO ₂	0	5.3	0.8088	1.081	1.055	16	1.0547	2.86	-
	0.167	8.6	0.8056	1.158	1.113	38	1.1128	2.67	3.68
	0.253	10.1	0.8021	1.203	1.155	50	1.1543	2.35	3.11
	0.361	16.9	0.8071	1.356	1.332	112	1.3317	2.01	2.77

2.2 Slim-tube displacement test

The slim-tube displacement experimental apparatus can be used to conduct miscibility experiments and identify minimum miscibility pressures (MMP). By drawing a comparison between the reservoir pressure

and MMP, the displacement pattern and ultimate recovery can be determined for the gas drive.

The schematic diagram of slim-tube experiment is shown in Fig. 1. The slim tube, 12 m long, 6 mm in outside diameter and 1 mm in wall thickness, is packed with 160–200 mesh fine sand.

The experimental procedure was as follows: 1) The sand-packed slim-tube was saturated with oil. 2) Gas injection. The Ruska pump was turned on and gas pressure in the gas injection cell was raised to a pressure, 1-3 MPa lower than the designed displacement pressure. The hand pump was adjusted to raise the backpressure to the designed displacement pressure. The exit valve of the slim tube was opened and gas pressure was adjusted to the displacement pressure or a little higher. The room temperature, atmospheric pressure, and the initial readings of gas flowmeter and Ruska pump were recorded. Displacement began at a given pump rate. 3)

During displacement, the volume of oil and gas displaced and the readings of the pump were monitored regularly. The injection volume of gas, the cumulative volume of outlet oil and the cumulative volume of outlet gas were recorded when gas breakthrough occurred. 4) The pump was turned off when the cumulative injection volume of gas was more than 1.2 PV. 5) The oil recovery was calculated at this displacement pressure. 6) The slim tube was cleaned and the above-mentioned procedure was repeated at another designed displacement pressure (Li, *et al.*, 2001; Liu, *et al.*, 2002; Yang, *et al.*, 2004; Hao, *et al.*, 2005).

Fig. 1 Schematic diagram of slim-tube experiment

1-Pressure gauge, 2-Digital display, 3-Back pressure controller, 4-Gas cylinder, 5-Intermediate container, 6-Forward displacement device, 7-Gas flowmeter, 8-Separator, 9-Ruska pump, 10-Capillary sight glass, 11-Gas injection cell, 12-Sand packed slim tube, 13-High pressure PVT analyzer

The plot of percentage oil recovery versus displacement pressure for CO₂ drive is shown in Fig. 2. As the pressure increased, the oil recovery when the cumulative injection volume of gas was 1.2 PV increased and reached a plateau above 29 MPa. Thus MMP for this oil was about 29 MPa for CO₂ displacement, which was less than those corresponding to hydrocarbon gas displacement (37 MPa) and nitrogen gas displacement (44 MPa). Since the formation fracture pressure is 34 MPa, the displacement mechanism is miscible drive in this block reservoir.

Fig. 2 Oil recovery versus displacement pressure
(gas injection volume 1.2 PV)

The effect of the proportion of CO₂ in the displacing agent on oil recovery was also investigated.

The compositions of the displacing agents are listed in Table 5.

Table 5 Compositions of displacing agents

Displacing agent	Mol.%										Total
	CO ₂	N ₂	C ₁	C ₂	C ₃	iC ₄	nC ₄	iC ₅	nC ₅	C ₆ ⁺	
Gas from Well Sheng-1-4	0.02	3.35	94.71	1.60	0.21	0	0.04	0	0	0.07	100
Gas from Well Fang-6	12.46	1.10	83.58	1.15	0.24	0	0.03	0	0	0.84	100
Hydrocarbon gas I	41.32	1.34	56.36	0.83	0.15	0	0	0	0	0	100
Hydrocarbon gas II	53.42	1.18	44.55	0.72	0.13	0	0	0	0	0	100
Pure CO ₂	100	0	0	0	0	0	0	0	0	0	100

Fig. 3 shows that oil recovery increased with increasing CO₂ proportion and the recovery by pure CO₂ displacement was 69.35%.

Fig. 3 Relationship between oil recovery and CO₂ proportion (gas injection volume 1.2 PV)

2.3 Core displacement test

Core displacement tests were performed to measure the threshold pressure and the threshold pressure gradient (Huang, 1998), so as to determine the feasibility of gas injection. The schematic diagram of core displacement test is shown in Fig. 4.

Fig. 4 Schematic diagram of core displacement tests

1-Micro pump, 2-Intermediate container, 3-Pressure gauge, 4-Valve, 5-Core holder, 6-Ruska pump, 7-Container, 8-Gas cylinder, 9-Thermostat

The oil sample used in all core displacement tests

was prepared with the crude oil from Well 184-124 in the Songfangtun Oilfield, and its viscosity was adjusted to 3.3 mPa·s (formation oil viscosity). The simulated formation water was prepared according to the salinity of formation water (7,158 mg/L). The gases used in the core tests were pure CO₂ and natural gas (its composition is shown in Table 1). The core samples used were natural cores obtained from Well Fang-188-138, except 2-1, 6-1, 11-1 and 15-1 which were from other oilfields, and their physical parameters are listed in Table 6.

Table 6 Characteristics of cores used

No.	Length cm	Diameter cm	Permeability 10 ⁻³ μm ²	Porosity %
1-1	7.62	2.52	0.38	10.96
1-2	7.16	2.52	4.12	15.06
2-1	6.80	2.52	7.28	16.97
2-2	6.71	2.52	4.36	16.91
6-1	7.34	2.52	13.42	17.20
10-1	7.40	2.52	0.39	6.18
10-2	7.44	2.52	0.55	8.31
11-1	6.76	2.52	6.54	18.95
12-1	7.85	2.52	5.25	17.00
12-2	7.67	2.52	5.02	16.58
14-1	6.96	2.52	1.24	12.48
15-1	7.23	2.52	12.68	16.68
15-2	7.33	2.52	3.74	15.74

1) The core sample was saturated with simulated formation water. 2) The water in core was displaced by oil till there was no water flowing out of the exit of core, ensuring that the oil and water saturations on core samples were similar to those under reservoir conditions. 3) Gas displacement. Pressure was applied to the core entrance and the pressure was gradually increased by using the measuring pump. After pressurization, the displacement pressure was recorded until the first drop of oil flowed out of the core exit. This pressure was

considered the threshold pressure.

The core displacement results (Table 7) indicate that the average threshold pressure gradients were 0.728 MPa/m for CO₂ displacement, 1.150 MPa/m for natural gas displacement, and 2.384 MPa/m for waterflooding. Hence, it is easier to implement gas displacement than

waterflooding in the Fang-48 fault block oil reservoir. Moreover, injecting the mixture of CO₂ and gaseous hydrocarbon is easier than injecting natural gas, and CO₂ injection is the easiest. In a word, it is feasible to implement gas displacement, especially CO₂ displacement in Fang-48 fault block oil reservoir.

Table 7 Core displacement test data

Core sample	Permeability 10 ⁻³ μm ²	Natural gas displacement		CO ₂ displacement		Waterflooding	
		Threshold pressure	Threshold pressure gradient	Threshold pressure	Threshold pressure gradient	Threshold pressure	Threshold pressure gradient
		MPa	MPa/m	MPa	MPa/m	MPa	MPa/m
1-1	0.380	0.215	4.71	0.150	3.28	0.280	6.13
10-1	0.387	0.150	3.84	0.065	1.66	0.250	6.39
10-2	0.551	0.150	2.06	0.059	1.57	0.220	5.84
14-1	1.243	0.062	0.89	0.050	0.72	0.155	2.23
15-2	3.736	0.039	0.53	0.016	0.22	0.095	1.30
1-2	4.115	0.015	0.44	0.007	0.20	0.080	2.32
2-2	4.364	0.048	0.72	0.032	0.48	0.011	1.64
12-2	5.018	0.019	0.43	0.015	0.20	0.040	0.52
12-1	5.252	0.050	0.64	0.049	0.62	0.040	0.51
11-1	6.541	0.012	0.18	0.011	0.16	0.034	0.50
2-1	7.279	0.013	0.19	0.010	0.15	0.048	0.71
15-1	12.681	0.008	0.11	0.007	0.10	0.025	0.35
6-1	13.419	0.006	0.08	0.005	0.07	0.014	0.19

3. Numerical simulation

ECLIPS software and CMG software were used to predict the main development indices of waterflooding

and gas displacement respectively at different injection pressures and volumes. Table 8 lists various development schemes with a simulation end time of Dec. 31, 2020.

Table 8 Development schemes

Scheme		Description	Maximum BHFP, MPa	Number of producers	Number of Injectors
1	Maintaining the present well pattern	Elastic drive BHFP in production well: 5.3 MPa	-	4	0
2	One additional water injector	BHFP in production well: 5.3 MPa Shut in when individual well water cut >95%	42	4	1
3	One additional gas injector Gas injected: gas from Well Shengqi-1-4	BHFP in production well: 5.3 MPa Shut in when individual well G/O> 1000 m ³ /m ³	36	4	1
4	One additional gas injector Gas injected: gas from Well Fangshen-6	BHFP in production well: 5.3 MPa Shut in when individual well G/O> 1000m ³ /m ³	36	4	1
5	One additional gas injector Gas injected: 41%CO ₂ +hydrocarbon	BHFP in production well: 5.3 MPa Shut in when individual well G/O> 1000 m ³ /m ³	36	4	1
6	One additional gas injector Gas injected: 53%CO ₂ +hydrocarbon	BHFP in production well: 5.3 MPa Shut in when individual well G/O> 1000 m ³ /m ³	36	4	1
7	One additional gas injector Gas injected: 100%CO ₂	BHFP in production well: 5.3 MPa Shut in when individual well G/O> 1000 m ³ /m ³	36	4	1

Notes: BHFP-bottom hole flowing pressure

The physical parameters of oil used in this model were obtained from the above-mentioned experiments. The simulation results (Table 9) illustrate that a higher oil recovery can be obtained by gas displacement. The average oil recovery by gas displacement is 10% higher than that by waterflooding. Furthermore, carbon dioxide displacement is better than hydrocarbon gas displacement, with a 15.32% improved recovery.

Table 9 Results of numerical simulation

Scheme	Maximum recovery, %	Incremental recovery, %	Increment versus waterflooding, %
1	2.61	-	-
2	11.87	9.26	-
3	19.79	17.18	7.92
4	21.88	19.27	10.01
5	24.02	21.41	12.15
6	24.84	22.23	12.97
7	27.19	24.58	15.32

4. Conclusions

1) The injection of both hydrocarbon gas and carbon dioxide can lead to an increase in oil formation volume factor and a decrease in density and viscosity, as well as an increase in saturation pressure. Moreover, the injection of carbon dioxide can lead to a much higher increase in oil formation volume factor.

2) Carbon dioxide has a lower MMP and higher displacement efficiency.

3) The MMP of CO₂ displacement is lower than the formation fracture pressure, thus CO₂ displacement mechanism in the Fang-48 block is miscible drive.

4) Core displacement tests show that the threshold pressure gradient of gas injection in the Fang-48 fault block oil reservoir is lower than that of waterflooding. So, it is easier to implement gas displacement than waterflooding.

5) Laboratory analysis and numerical simulation indicate that a higher oil recovery can be achieved by gas displacement than by waterflooding, and carbon dioxide displacement can obtain a higher oil recovery than hydrocarbon gas displacement. Carbon dioxide displacement is recommended for the development of the Fang-48 fault block oil reservoir.

References

- Hao Y. M., Chen Y. M. and Yu H. L. (2005) Determination and prediction of minimum miscibility pressure in CO₂ flooding. *Petroleum Geology and Recovery Efficiency*, 12(6), 64-66 (in Chinese)
- Huang Y. Z. (1998) *Fluid Flow Mechanism in Low-Permeability Reservoir*. Beijing: Petroleum Industry Press, 59-99 (in Chinese)
- Li S. L., Zhang Z. Q. and Ran Q. Q. (2001) *Gas Injection Technique for EOR*. Chengdu: Technology Press of Sichuan, 22-24 (in Chinese)
- Liu B. G., Zhu P., Yong Z. Q. and Lü L. H. (2002) Pilot test on miscible CO₂ flooding in Jiangsu Oilfield. *Acta Petrolei Sinica*, 23(4), 56-60 (in Chinese)
- Yang X. F., Guo P., Du Z. M. and Chen J. L. (2004) Influence factors appraisal of slim-tube simulation to determine the minimum miscibility pressure. *Journal of Southwest Petroleum Institute*, 26(3), 4-44 (in Chinese)

About the first author

Cui Lining was born in 1982 and received her bachelor degree from Daqing Petroleum Institute in 2004. Now she is studying for her master's degree in China University of Petroleum (Beijing), with her main interests in EOR engineering and oilfield chemistry.

E-mail: clnyydd@126.com

(Received July 24, 2006)

(Edited by Sun Yanhua)