Determination of minimum near-miscible pressure during CO_2 flooding in an offshore oilfield

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Abstract. CO_2 near-miscible flooding was proposed for the development of the newly discovered offshore Qinhuangdao oilfield. However, different with miscible flooding, the near-miscible flooding corresponds to a region instead of a point (MMP). This paper focuses on the determination of the lower and upper boundaries of the near-miscible area. Based on the data of PVT test, a compositional model was established and fitted. Then slim tube simulation and empirical equation were conducted to obtain the minimum near-miscible pressure (MNMP). The results can provide valuable guidance for the effective development of the targeted offshore oilfield.

1. Introduction

A new offshore oilfield of China was discovered recently. However, effective development was facing significant challenge considering the main characterizes of complex lithology and strong heterogeneity. Water flooding is regarded to be unsuitable due to the small pores and throats, and low infectivity. Thus, CO_2 flooding was proposed and the feasibility aroused increasingly attention in the past 3 years. CO_2 miscible flooding is the leading EOR processes, which is recognized as one of the most promising methods for enhancing oil recovery [1]. In view of the limitations of gas sources, continental sedimentary environments and poor crude oil characteristics, the application of miscible flooding is very difficult in China [2]. In 1994, Thomas et al. presents a new perspective that a degree of immiscibility, named "near-miscible", is equally adequate for field implementation in enhanced oil recovery processes. Also, because of an extensive research of indoor experiments and field tests, the reason for some floods being very successful while others being miserable is closely related to the measurements used to evaluate the miscibility degree. In fact, as Thomas et al (1994) provided, the MMP associated with slim tube test would normally be expected to be overestimated compared with the results of multi-contact testing [3].

Many laboratory tests and some filed implementations have indicated that near-miscible injection can obtain a comparable performance as miscible flooding. Based on the experimental results, Shyeh-Yung et al (1991). claimed that for a certain pressure range below MMP, the tertiary gas flooding recoveries do not decrease as sharply as that of slim tube tests. It was concluded that CO_2 mobility decrease as pressure decrease which provides possible mobility control benefits during near-miscible

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injection [4]. Based on core flooding tests and numerical simulations, Schechter et al (1998). obtained similar results when pressure reduces from above the MMP to near the MMP [5]. By extensive experimental test of tertiary gas injection, Grigg et al (1997). verified that oil recovery of gas injection can still be very high when pressures reduce but near the MMP [6].

Obviously, near-miscible flooding sounds very attractive. Besides, from both economic and operational standpoints, with the decrease of injection pressure, lower inject ant density and lower costs in compression is needed. However, to our knowledge, how to define a near-miscible region near MMP is one of the key questions. Theoretically, near-miscible flooding refers to gas injection that does not quite develop complete miscibility with the oil, but come close [7].

In this paper, both crude oil and solution gas samples from QHD 29-2 offshore oilfield were taken as an example, PVT tests were conducted first to obtain the physical characteristics of the oil-gas system. On this basis, a compositional model was built and fitted with the experimental data. Then both empirical equations and slim tube simulation were conducted to forecast the MMP. Meanwhile, the relationship of displacement efficiency, IFT and injection pressure were obtained. A new pressure region was divided and named near-miscible interval through the analysis of the denser test points.

2. Methodology

2.1. Experimental
The oil and gas samples are collected from the well 29-2E-4 in QHD 29-2 offshore reservoir. Table 1 and Table 2 are the physical properties of crude oil and composition of oil-solvent system, respectively. The live oil was recombined using RUSKA-2730 high pressure high temperature visual PVT apparatus produced by Ruska Company (Houston, Texas, USA). More details of the operation procedure to conduct PVT test can be found in previous publications [8].

Table 1. Physical properties of crude oil.

	Parameters	Value	Units
Reservoir condition	Pressure	36.53	MPa
	Temperature	122.5	℃
Fluid properties	Saturation pressure	11.11	MPa
	Gas/oil ratio	64.0	m^3/m^3
	Volume coefficient of the oil	1.224	m^3/m^3
	Oil density (reservoir condition)	0.7352	g/cm^3
	Oil viscosity (reservoir condition)	0.67	mPa.s
	Died oil density	0.8329	g/cm^3
Composition of Well-flow content	C_1+N_2	26.10	%
	$CO_2+C_2\sim C_{10}$	37.92	%

2.2. Simulation
A compositional model was established by component lumping technique using PVT i, Eclipse 300. EOS parameters were adjusted to fit the PVT data. Molecular weight of the plus fraction was adjusted to match the oil density. Coefficients of Pedersen viscosity components were adjusted to match the oil viscosity. Binary interaction coefficients between CO_2 and hydrocarbon components as well as CO_2 volume shift factor were adjusted to match saturation pressure. With the model, slim tube simulation was conducted and parameters of displacement efficiency and IFT can be obtained.

2.3. Empirical Formulas
Several empirical formulas for predicting MMP of CO_2 and oil systems based on the specific conditions of crude oil and gases were summarized in Table 3. On this basis, according to the

compositions of crude oil, solution gas, and injection gas, MMP can be calculated and compared with the results of slim tube simulation.

Table 2. Composition of oil-solvent system.

Component	Oil composition, mo l%	Solvent, mo l%	Well stream composition, mo l%
CO_2	0.00	2.01	0.77
N_2	0.00	2.44	0.93
C_1	0.12	65.8	25.17
C_2	0.20	11.36	3.67
C_3	0.78	9.3	4.57
iC_4	0.43	10.73	1.19
nC_4	1.47	2.43	2.76
iC_5	1.24	4.84	1.25
nC_5	1.83	1.27	1.48
C_6	6.94	0.92	4.38
C_7	7.10	0.24	4.40
C_8	7.14	0.02	4.42
C_9	7.77	0.00	4.81
C_{10}	6.81	0.00	4.22
C_{11+}	58.17	0.00	35.98
sum	100	100	100

Table 3. Empirical formulas.

	Empirical formulas
Cronquist (1978)	$MMP = 12.6472 + 0.015531 \times (1.8T_R + 32) + 1.24192 \times 10^{-4} \times (1.8T_R + 32)^2 - 716.9427 / (1.8T_R + 32)$
Yelling and Metcalfe (1980)	$MMP = 0.11027 \times (1.8T_R + 32)^Y$ $Y = 0.744206 + 0.0011038 \times MW_{C5+} + 0.0015279 \times V_{ol}$
Alston et al (1985)	$MMP = 6.056 \times 10^{-6} \times (1.8T_R + 32)^{1.06} \times (MW_{C5+})^{1.78} \times (Vol / Int)^{0.136}$ $P_b < 0.345MPa, MMP = 6.056 \times 10^{-6} \times (1.8T_R + 32)^{0.106} \times (MW_{C5+})^{1.78}$
Glaso (1985)	$F_R > 18mol\%; MMP = 5.58657 - 0.02347739 \times MW_{C7+} + (1.1725 \times 10^{-11} \times MW_{C7+}{}^{3.73} \times e^{786.8 \times MW_{C7+}{}^{-1.058}}) \times (1.8T_R + 32)$ $F_R < 18mol\%; MMP = 20.33 - 0.02347739 \times MW_{C7+} + (1.1725 \times 10^{-11} \times MW_{C7+}{}^{3.73} \times e^{786.8 \times MW_{C7+}{}^{-1.058}}) \times (1.8T_R + 32) - 0.836 \times F_R$
Alston et al (1985)	$F_{impure} = \left(\frac{87.8}{1,8T_{cm} + 32}\right)^{\frac{1.935 \times 87.8}{1.8T_{cm} + 32}}, T_{cm} = \sum w_i T_{ci}$
Sebastian et al. (1985)	$F_{impure} = 1 - 2.13 \times 10^{-2}(T_{cM} - 304.2) + 2.51 \times 10^{-4} \times (T_{cM} - 304.2)^2 - 2.35 \times 10^{-7} \times (T_{cM} - 304.2)^3, T_{cM} = x_i T_{ci}$
Yuan et al. (2004)	$\frac{MMP_{impure}}{MMP_{CO_2}} = 1 + m(x_{co_2} - 100), m = a_1 + a_2 MW_{C7+} + a_3 F_R + (a_4 + a_5 MW_{C7+} + a_6 \frac{F_R}{MW_{C7+}}) T_R + (a_7 + a_8 MW_{C7+}{}^2 + a_{10} F_R) T_R{}^2$

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3. Results and discussion

3.1. Compositional model based on PVT test

Based on component chopping technique, 7 pseudo components were divided. Parameters such as the saturation pressure, liquid density, liquid viscosity and gas oil ratio (GOR) are matched with the experimental data. Thus, a compositional model based on the PVT test was established to represent the real oil and gas system of the targeted well. Also, according to vaporizing gas drive mechanism, MMP of the reservoir fluids with CO_2 can be roughly estimated. For the targeted oil and gas sample, the forecasted MMP is 30.99 MP a. It should be noted that this estimation depends on the IFT value, which is strictly set to be zero according to the miscibility definition.

3.2. Slim tube simulation

Compared with the conventional slim tube test, simulation study can provide more data such as oil and gas production, GOR, IFT, and viscosity, density and saturation of both oil and gas phases. According to the definition of miscibility, 100% of displacement efficiency can be obtained with the development of a zero IFT. However, the criterion of slim tube test is to determine the discontinuity on a displacement and pressure plot. Obviously, it is only a convention instead of an indication of miscibility. Similarly, a threshold IFT value of 0.001mN/m was regarded as miscibility [9]. It is totally different from the physical definition of miscibility but has great engineering significance. As is shown in Fig.1, the MNMP and MMP can be estimated as 25.18 MP a and 30.57 MP a, respectively. While the IFT in Fig.2 reduces sharply first but then decrease much slower. The breakpoint is not easy to be distinguished. Thus, semilog coordinate is used and a distinct breakpoint of 24.81 MP a can be determined clearly. Hence, the pressure region of near-miscible flooding determined by displacement efficiency and IFT are [25.18-30.57] MP a and [24.81-29.11] MP a, respectively. Obviously, the results are very close. And the ratio of MNMP to MMP is about 0.85.

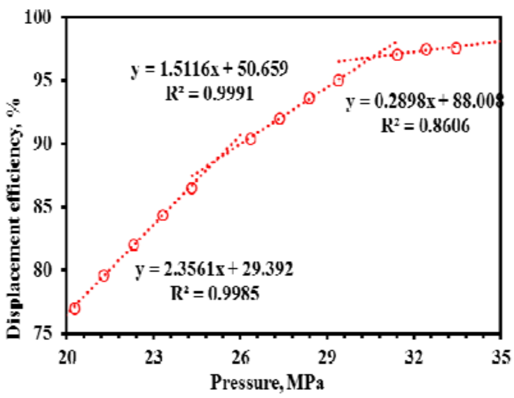

Fig. 1 displacement efficiency VS Pressure

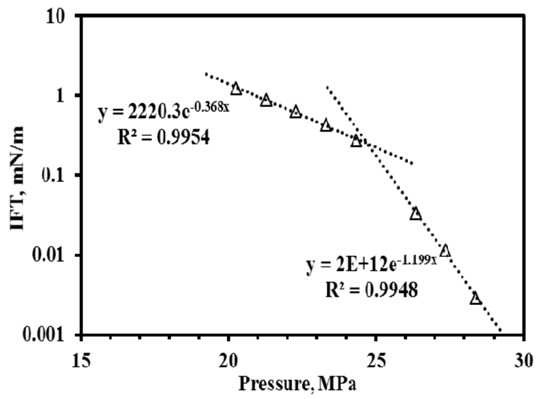

Fig. 2 IFT VS Pressure

3.3. Empirical formulas

Empirical correlation is also one of the methods to determine MMP of oil and gas systems, especially for the initial screening of gas flooding. Reservoir temperature is considered to one of the main factors that affect MMP. Besides, the molecular weight of a plus fraction, and the mole fraction of a light component in the reservoir oil, are also important factors. It is obvious that the relative errors compared with the simulation results are not very satisfactory. Two main reasons are regarded for this big deviation. For one thing, most of the correlations are built based on specific reservoirs with very limited data. For another, thermodynamic properties are less predictable near critical region, a slight deviation of the reservoir conditions, fluid properties or composition may cause big difference.

4. Conclusion

Comparatively, MMPs determined by vaporizing gas drive during the establishment of compositional model are highest. A main reason is that MMP is estimated strictly according to the definition where the corresponding IFT declined to zero. Based on the change of displacement efficiency and IFT with injection pressure, the pressure interval for near-miscible flooding of the well QHD 29-2E-4 in QHD offshore oilfield was determined from an engineering point of view. With more pressure points, the trend of both displacement efficiency and IFT with injection pressure can be clearly identified. Thus, near MMP, the interval which deviates the linear relationship of the data away from the MMP in both miscible and immiscible regions, can be divided and defined. It is found that the ratio of NMMP to MMP is between 0.80 and 0.86 in the targeted well, which means some reservoirs cannot achieving miscible flooding, or cannot keeping the required pressures, can also obtain satisfactory recovery by near-miscible flooding. Displacement efficiency of (88-96%) and IFT of (0.05 to 0.001) mN/m are regarded as the typical indexes for near-miscible flooding from the view of engineering significance.

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