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Experimental Study on Phase Characteristics of CO_2 Injection in BZ13-2 Strong Volatile Oil Reservoir in Bohai Sea Buried Hills

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Abstract

BZ13-2 oil field is a deep submerged strongly volatile reservoir in Bohai Sea. This oil reservoir has the characteristics of high gas oil ratio and small difference in formation pressure and saturation point pressure. It usually adopts gas injection development to avoid crude oil degassing and fast decreasing production capacity. However, the phase characteristics and miscibility mechanism of this high-temperature and high-pressure fluid after gas injection are not clear. Therefore, it is necessary to study the feasibility of CO_2 injection to improve oil recovery in near critical volatile oil reservoirs through CO_2 injection experiments. In the early stage of the depletion experiment, the content of heavy components in the remaining oil increased significantly, so the depletion method is not conducive to the development of such reservoirs. With the increase of CO_2 injection, the volumetric expansion coefficient of formation crude oil increases significantly, while the saturation pressure and formation crude oil viscosity remain basically unchanged. The minimum miscible pressure experiment shows that CO_2 injection under formation pressure conditions can achieve multiphase miscibility. Based on experimental research results, the BZ13-2 oilfield is suitable for early gas injection development and can significantly improve recovery.

Keywords

Bohai Buried Hills, Strongly Volatile Reservoir, Gas Injection and Development, Phase Characteristics, Fine Tube Experiment

1. Introduction

CO_2 injection recovery enhancement technology has a wide application prospect in the world, which can effectively improve the recovery of crude oil [1] [2] [3].

CO_2 injection drive is a dynamic process, and the physical properties of the crude oil in the CO_2 formation crude oil system continuously change over time. As the dissolution of CO_2, the viscosity of crude oil decreases and the expansion coefficient increases [4]. In addition, due to the mass transfer effect of CO_2 and crude oil, the interfacial tension between gas and oil gradually decreases or even disappears, and oil gas miscible can effectively improve oil displacement efficiency [5] [6]. Simultaneously injecting CO_2 is of great significance for achieving carbon neutrality as soon as possible [7] [8] [9].

BZ13-2 oil field is a deep submerged strongly volatile reservoir in Bohai Sea. This oil reservoir has the characteristics of fracture development, high gas oil ratio and small difference in formation pressure and saturation point pressure. It's usually using gas injection development to avoid crude oil degassing and fast decreasing production capacity [10] [11]. However, the BZ13-2 oilfield has high-temperature and high-pressure conditions, and the phase characteristics and miscible mechanism of the fluid after gas injection are not clear. In order to explore the feasibility of CO_2 injection to improve the recovery rate of the near-critical state volatile reservoir, it is necessary to systematically carry out CO_2 injection experiment to study the effect of CO_2 injection on the phase characteristics and the miscible mechanism. Based on experimental research, provide reliable basis for efficient development and optimization plans of similar oil fields.

2. Oilfield Overview

The BZ13-2 oilfield is located at the central sea area of the Bohai Sea. Structurally, it appears as a semi anticline structure that is complicated by strike slip faults and their derivative faults. The oil-bearing series of the oilfield is the Archaean metamorphic granite buried hill, with a burial depth of −4200 - −5000 m. The reservoir lithology is mainly Gneiss with diorite porphyrite. The porosity of the reservoir is 3% - 6.5%, the average porosity is 4.25%. The permeability is 1.3 - 2.76 mD, the average permeability is 2.11 mD. The fracture density is 1.39/m - 4.8/m, the average is 2.5/m. The original formation temperature is 175.1˚C, the formation pressure is 46 MPa, normal temperature and pressure system. The density of surface crude oil is 0.812 g/cm^3, the viscosity of surface crude oil is 2.3 mPa·s, the sulfur content is 0.02%, the wax content is 19.4%, the freezing point is +21˚C, with the characteristics of low density, low viscosity, low sulfur content, high wax content and high freezing point.

3. Phase Characteristics of the Formation Fluid at High Pressure

3.1. Analysis of the Original Formation Fluid High Pressure Physical Properties

In the composition of the original formation fluid in BZ13-2 oilfield, the C1 + N2 content accounts for 64.791%; C2 - C6 + CO_2 content accounts for 21.869%;

C7+ content accounts for 13.34%. Compared with the composition of volatile oil in other domestic oilfields, the formation fluid in BZ13-2 oilfield belongs to the volatile oil system with high methane content, medium to high intermediate hydrocarbon content and heavy hydrocarbon content. The single degasification experiment gas-oil ratio is 682 m^3/m^3, which is a high dissolved gas formation fluid with sufficient elastic energy. The volume coefficient of formation crude oil is 3.0548, the contraction rate of formation crude oil is 67.26%, and the dissolved gas extraction and oil drive effect is good. The density of formation crude oil is 0.4229 g/cm^3, and the viscosity of formation crude oil is 0.0871 mPa·s, which is a light volatile oil fluid. According to the original formation fluid P-T phase diagram, the critical temperature is 179˚C, the critical pressure is 45.13 MPa, the saturation pressure is 45.52 MPa, and the difference between formation pressure and saturation pressure is 0.48 MPa (see **Figure 1**). Due to the very small difference between formation pressure and saturation pressure, the oil field is easy to degas after production to affect the recovery rate, so it is recommended to take gas injection development.

3.2. Residual Oil Components at Different Depletion Pressures

As the depletion pressure decreases, the proportion of each component in the remaining oil changes significantly. Overall, the content of light components gradually decreases while the content of heavy components gradually increases (see **Figure 2**), and the oil quality becomes worse and worse. The P-T phase diagram gradually shifts to the lower left, and the two-phase area changes from wide and short to narrow and long, but it is still in the volatile oil system. As the pressure drops to 40 MPa, the C1 component content decreases from 64.63% to 56.96%, a decrease of 11.9%, and the C11+ component content increases from 6.46% to 16.39%, an increase of 153.7%. It indicates that the degree of heavy

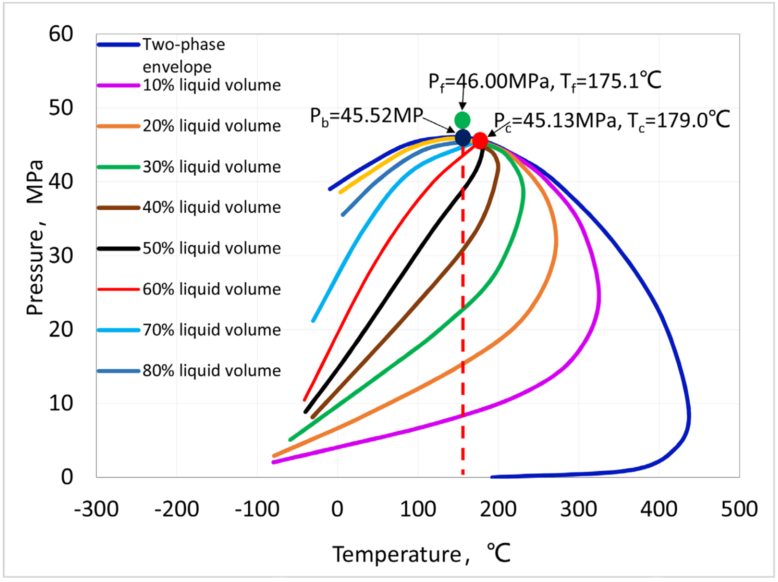

Figure 1. P-T phase diagram of the formation fluid.

components in the remaining oil is higher. Therefore, it is recommended to use gas injection development to avoid formation degassing.

4. Experimental Study of Phase Change of Formation Fluid Injection CO_2

4.1. Effect of CO Injection$_2$ on the Saturation Pressure of Formation Oil

After the injection of CO_2, the saturation pressure of formation crude oil showed an overall increasing trend while the increase was limited (see **Figure 3**). The saturation pressure of CO_2 - formation crude oil system increased from 45.51 MPa to 45.53 MPa when CO_2 injection is 20 mol%, and the saturation pressure of CO_2 - formation crude oil system increased to 45.68 MPa when CO_2 injection is 50 mol%.

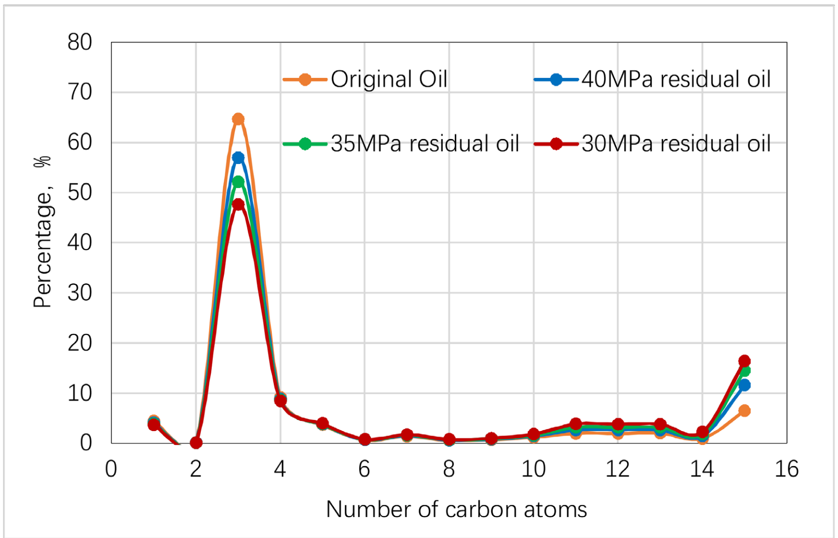

Figure 2. Content of each component under different pressure.

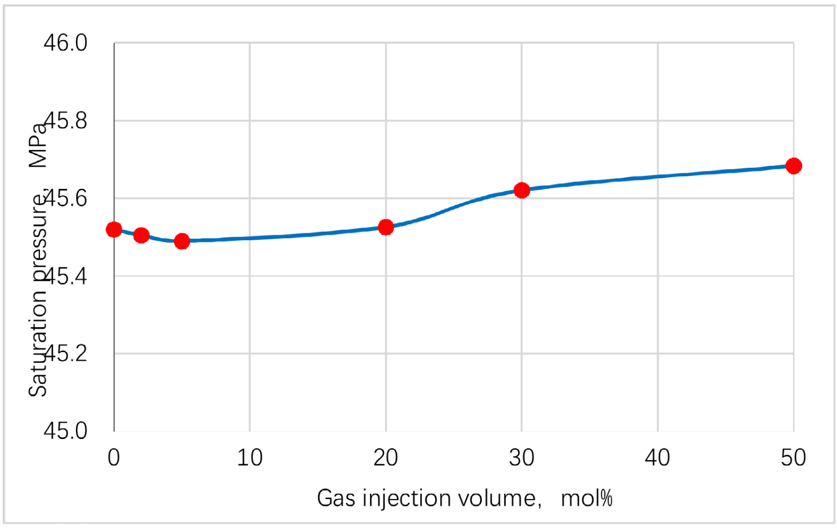

Figure 3. Saturation pressure versus gas injection volume curve.

4.2. Effect of CO_2 Injection on the Volume Factor of Formation Oil

The volume expansion factor refers to the ratio of the volume of crude oil injected with CO_2 to the volume of crude oil under saturation pressure conditions. This parameter reflects the impact of CO_2 injection on the volume of crude oil. When the CO_2 injection is 20 mol%, the volume expansion factor of CO_2 - formation crude oil system increases from 1.0 to 1.195, with a change of 20% (see **Figure 4**), indicating that the CO_2 injection has a significant impact on the volume expansion of volatile oil reservoirs.

4.3. Effect of CO_2 Injection on the Viscosity of Formation Oil

After the injection of CO_2, the formation oil viscosity decreases with the increase of CO_2 dissolved amount in the formation oil while the effect is not significant. When the CO_2 injection is 50 mol%, the formation crude oil viscosity decreases from 0.0885 mPa·s to 0.0873 mPa·s, and the decrease is only 1.4%.

4.4. Effect of CO_2 Injection on the Percentage of Liquid Content of Formation Oil

With the increase of CO_2 injection amount, the percent of the liquid content of CO_2 - formation crude oil system changed significantly (see **Figure 5**). At a CO_2 injection is 2 mol%, when the pressure is formation pressure, all of CO_2 is dissolved in the formation crude oil, and all of CO_2 - formation crude oil system is petroleum liquid with 100% liquid content. When the pressure drops to the bubble point pressure, the liquid content percentage drops rapidly to 53%, and then decreases slowly and linearly. When the pressure drops to the 15 MPa, the liquid content percentage is 18%. At a CO_2 injection is 5 mol%, when the pressure is formation pressure, CO_2 - formation crude oil system quickly reverses the phase, all condensate gas system, containing 0% liquid percentage. When the pressure drops to the dew point pressure, condensate rapidly precipitates,

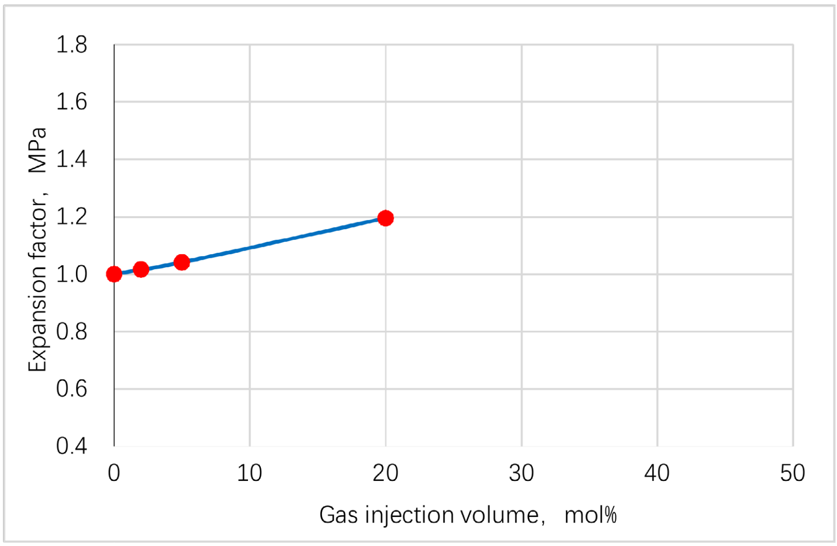

Figure 4. Expansion factor versus gas injection volume curve.

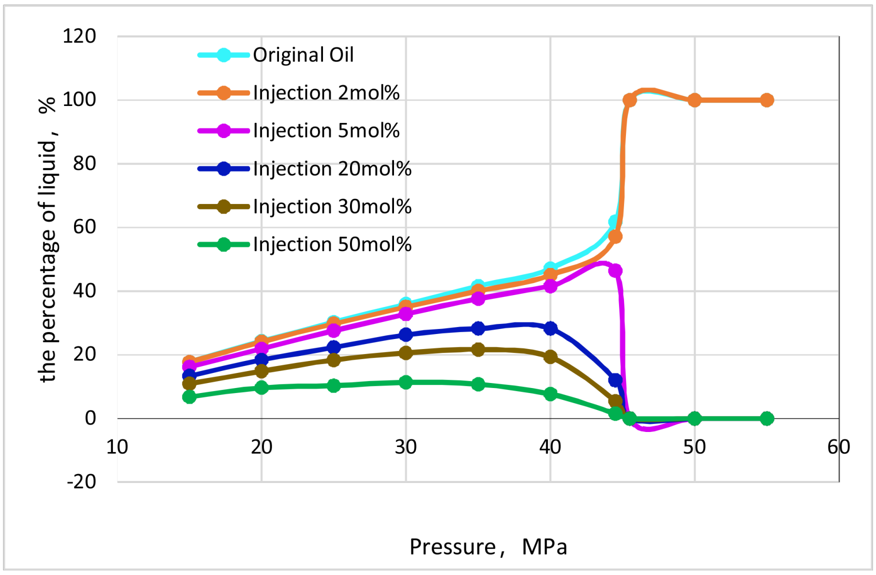

Figure 5. Liquid percentage versus pressure curve under different gas injection.

containing 48% liquid percentage, and then slowly linearly decreases. When the pressure of 15MPa, containing 17% liquid percentage. Therefore, injecting CO_2 can turn volatile oil into condensate gas, which is beneficial for the recovery of formation fluids.

5. The Minimum Miscibility Pressure by Fine Tube Experiment

5.1. Experimental Setup

The experimental equipment mainly consists of displacement system, thermostat box, intermediate vessel, fine tube model, high pressure observation window, back-pressure regulator, separation device, oil and gas measurement device (see Figure 6). Among them, the repulsion system is RUSKA fully automatic pump, the maximum working pressure of 70 MPa, flow rate accuracy 0.001 ml/s. The maximum temperature of the thermostat box 200˚C, temperature control accuracy 0.1˚C. The thin tube model 15 m, the inner diameter of 3.8 mm, the maximum pressure of 70 MPa, the maximum temperature of 180˚C.

5.2. Experimental Samples

The sample of saturated crude oil in the fine tube is a sample of formation crude oil formed by degasified oil and associated gas from well BZ-5 provided under actual reservoir temperature and pressure conditions (175.1˚C, 45.54 MPa), with 99.96% purity of injected fluid CO_2.

5.3. Experimental Process

1) Cleaning of the fine tube model. The fine tube model was cleaned before the experiment, injected with nitrogen or aviation kerosene, and constant to the experimental temperature and pressure.

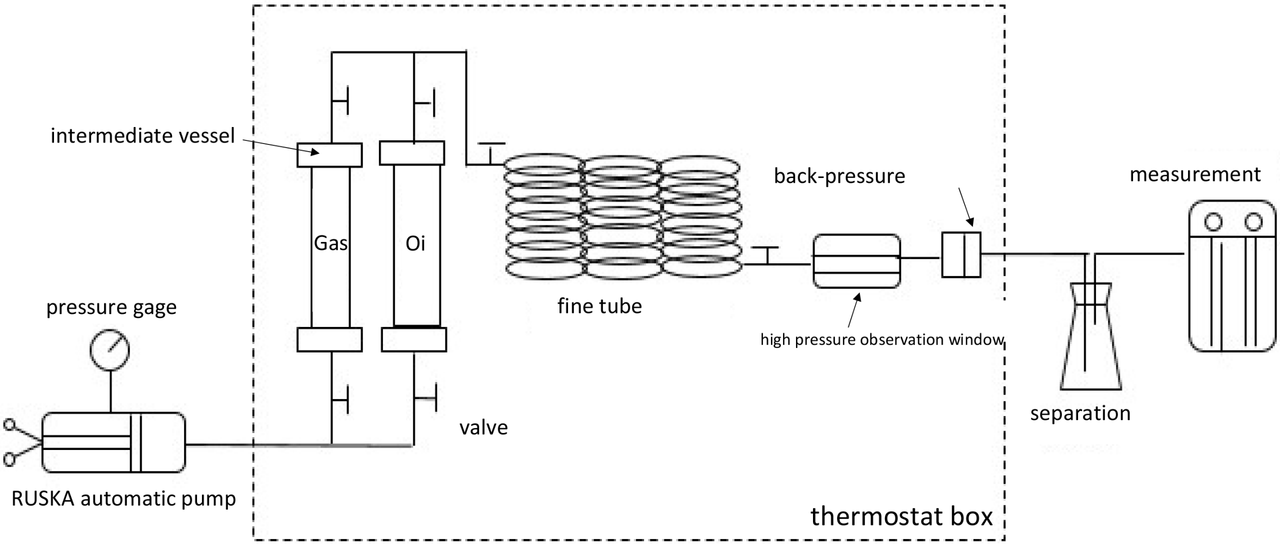

Figure 6. Flow chart of the fine tube experiment.

2) Saturated crude oil sample. Repel the nitrogen or aviation kerosene in the fine tube with the sample of formation crude oil at a rate of 60 cml/h - 90 ml/h. After repelling to 2.0 times the pore volume, measure the output sample components and gas-oil ratio, and stop repelling when it is consistent with the sample of formation crude oil.

3) Gas injection displacement experiment. Fill the intermediate vessel with injection gas at the experimental temperature and pressure and keep the equilibrium. Inject the gas into the fine tube to repel the crude oil at 0.05 - 0.1 MPa above the experimental pressure, the repulsion rate is 0.125 ml/min, and stop the repulsion after injecting 1.2 PV gas.

4) Experimental data processing. After each injection of 0.1 - 0.15 PV gas, the output oil and gas volume, pump flow, injection pressure and back-pressure were recorded once. The changes of the extracted gas components were analyzed by gas chromatograph. The collected data were collated and the minimum miscibility pressure was calculated after the experiment.

5.4. The Analysis of CO_2 Injection in Fine Tube Experiment

The injection CO_2 miscible-phase drive mechanism is mainly dissolution to reduce the viscosity of crude oil, improve the volume expansion coefficient of crude oil, increase the formation elastic energy, eliminate the oil-gas interfacial tension, form a mixed single-phase fluid, avoid the Jamin effect, and significantly improve the degree of recovery [12]. With the increase of injected gas, the gas-oil ratio breakthrough time is later and the crude oil recovery rate is higher than 90%. In the fine tube replacement experiment, the 3rd, 4th and 5th injection pressures were 45.54 MPa, 46 MPa and 49 MPa. From the curves of different injection PV numbers and gas-oil ratio (see **Figure 7**), it shows that the breakthrough time of gas injection was relatively late in all three experiments, and the breakthrough time was after the injection of 1.1 PV (CO_2 injection volume was

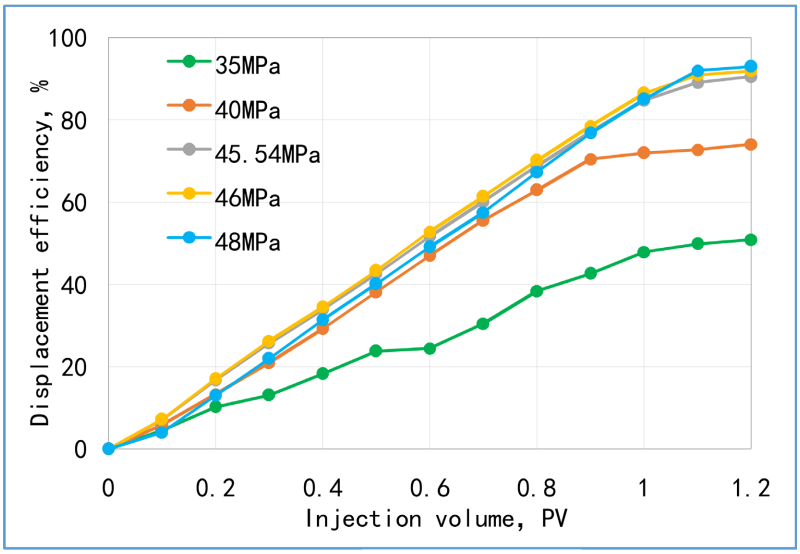

Figure 7. Oil displacement efficiency versus injection volume curve under different pressures.

1.1 times of pore volume). The recovery of three experiments were 90.62%, 91.96% and 93.07%, respectively. All of them are higher than 90%, while the fluid in the observation window also shows mixed-phase fluid characteristics.

The injection CO_2 non-miscible-phase drive mechanism is mainly dissolution to reduce crude oil viscosity, increase crude oil volume expansion coefficient, increase formation elastic energy, reduce oil-gas interfacial tension and enhance crude oil flow ability [13]. In contrast to miscible-phase drive, with the increase of PV number of injected gas, the injected gas breakthrough is earlier and the recovery increases limitedly after the gas breakthrough, generally below 90%. In the fine tube displacement experiment, the injection pressures used in the first and second drives were 35 MPa and 40 MPa, respectively. The curves of different injection volume and gas-oil ratios showed that the gas breakthrough time was relatively early, at 0.70 and 0.80 PV, respectively (see **Figure 7**). The oil recovery was 50.9% and 74.1%, which were lower than 90%. The fluid in the observation window also showed the characteristics of non-mixed-phase fluid.

According to the relationship curve between the experimental pressure and the degree of recovery, it shows that the oil recovery increases continuously with the increase of the pressure. There is a turning point in the increase characteristic at 43.2 MPa (see **Figure 8**). When the pressure is less than 43.2 MPa, the oil recovery increases significantly with the experimental pressure while all of them are less than 90%. When the pressure is higher than 43.2 MPa, the oil recovery increases unsignificant and all the oil recovery is higher than 90%. According to the experimental data of different stages, the trend lines of miscible-phase drive and non-miscible-phase drive were regressed separately, and the minimum miscible pressure of CO_2 injection in BZ13-2 oilfield was calculated to be 43.2 MPa. Under the current formation temperature and pressure conditions in the bz13-2 oilfield, injecting CO_2 can achieve miscible flooding.

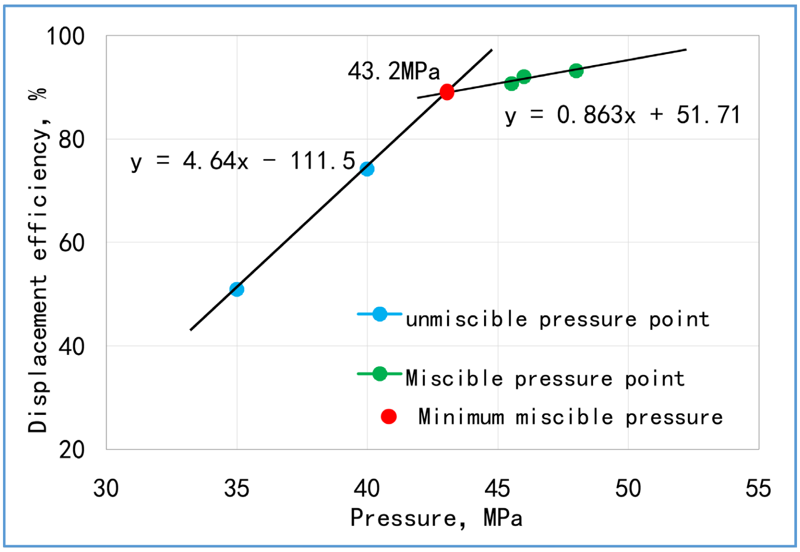

Figure 8. Oil displacement efficiency versus pressure curve.

6. Conclusions and Recommendations

1) The formation fluid of BZ13-2 oilfield is volatile oil with high methane content, medium to high intermediate hydrocarbons and heavy hydrocarbons. It needs to be developed with gas injection because of the small difference between formation pressure and saturation pressure, high gas-oil ratio.

2) The volume of crude oil expands significantly after CO_2 injection. The saturation pressure and oil viscosity remain basically unchanged. The CO_2 - formation crude oil system undergoes phase inversion soon after gas injection, which is conducive to improving the recovery rate.

3) The minimum miscible pressure experiments in long thin tubes were conducted to clarify the displacement characteristics corresponding to different experimental pressures. By regressing the trend lines of different characteristics, the minimum miscible pressure is calculated to be 43.2 MPa. Under the current formation temperature and pressure conditions in the bz13-2 oilfield, injecting CO_2 can achieve miscible flooding.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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