



Determination and controlling of gas channel in CO₂ immiscible flooding



Xianggang Duan ^{a, b, c}, Jirui Hou ^{a, b, c, *}, Fenglan Zhao ^{a, b, c}, Yunfei Ma ^{a, b, c},
Zongxun Zhang ^{a, b, c}

^a Research Institute of EOR, China University of Petroleum, Beijing 102249, PR China

^b Key Laboratory of Enhanced Oil Recovery, CNPC, Beijing 102249, PR China

^c Key Laboratory of Petroleum Engineering (Ministry of Education), Beijing 102249, PR China

ARTICLE INFO

Article history:

Received 5 December 2014

Received in revised form

16 January 2015

Accepted 19 January 2015

Available online 23 January 2015

Keywords:

CO₂ immiscible flooding

Dissolution and diffusion

Gas flow law

Breakthrough

Channeling

ABSTRACT

In order to study the effect of gas channel on CO₂ flooding in porous medium, the gas flow velocity is divided into two parts: gas breakthrough stage and gas channeling stage. The breakthrough velocity has an exponential relationship with concentration in the frontal zone of gas area, while the channeling velocity has a linear relationship with injection pressure drop. A new method is proposed to determine the gas channeling time by using the trend line of gas–oil ratio in gas breakthrough and gas channeling stage. The production characteristics in CO₂ flooding show that recovery greatly improves after the gas breakthrough at the outlet of core sample, and most of the oil displaces before gas channeling. Thus, the extension of the stage between gas breakthrough and gas channeling becomes a key factor to improve CO₂ recovery efficiency. Improving the injection pressure drop increases the dissolved gas diffusion, which will improve the oil displacement efficiency of simultaneous oil and gas production stage, but it also increases gas channeling velocity, which will increase the gas/oil ratio sharply and result in ineffective gas injection. An optimal displacement pressure can control the diffusion rate, the channeling rate and improve the recovery of CO₂ flooding effectively. Keeping a constant pressure drop, increasing of injection pressure can not only increase the diffusion rate, but also reduce the gas channeling velocity. The achievement of a lower gas channeling velocity is advisable for extending the stage of gas–liquid production, and improving the immiscible CO₂ recovery significantly.

© 2015 Energy Institute. Published by Elsevier Ltd. All rights reserved.

1. Introduction

In recent years, with the development of greenhouse gas CO₂ capture and geological storage (CCS) technology, CO₂ enhance oil recovery (EOR) projects increase significantly [12]. CO₂ flooding technology has become one of the most attractive methods to improve overall oil recovery efficiency [5,6,8,22]. Moreover, CO₂ flooding technology has been further promoted by some new CO₂ technologies, recently researched and applied, such as CO₂ gas membrane separation technology, immiscible gas assisted gravity drainage (GAGD) [23,26,28] and CO₂ corrosion resistance technology (Cr alloy steel) [3]. The United States and some other countries are developing their own CO₂ miscible flooding technology to improve oil recovery [13]. In China, CO₂ flooding oil-displacement experiments in Daqing Changyuan oilfield and JiLin Fuyu oilfield demonstrated that the CO₂ flooding technology is an effective method for developing oil recovery in low permeability reservoirs [2,24,26,28].

However, in most oilfields in China CO₂ miscible flooding is hard to achieve due to the limitation of formation condition and crude oil properties [31]. For example, the stratum of YanChang oilfield belongs to low porosity (average value: 11.2%) and low permeability (average value: $1.49 \times 10^{-3} \mu\text{m}^2$) reservoir. The initial formation pressure is 12 MPa, current formation pressure is 9 MPa, and the fracturing pressure in formations is 20 MPa. Since the minimum miscible pressure of crude oil and CO₂ is 22.15 MPa, it is difficult to carry out CO₂ miscible flooding to enhance oil recovery [21,34,35]. However, compared to CO₂ miscible flooding, CO₂ immiscible flooding has encountered serious problems in current laboratory experiments and oilfield applications, such as gas breakthrough and low sweep efficiency [15,26,28]. The

* Corresponding author. Research Institute of EOR, China University of Petroleum, Beijing 102249, PR China.

E-mail address: Houjirui@126.com (J. Hou).

disadvantage of mobility rate results in the low EOR effects, and the CO₂ flooding usually cannot reach the expected effect [9]. Thus, the gas flow control and breakthrough in the porous media became a critical problem that needs to be solved in CO₂ immiscible flooding [10,18,20].

Literatures discussed several methods to control the gas mobility and reduce the gas breakthrough time, such as water alternative gas injection (WAG) [25], simultaneous water alternative gas injection (SWAG), surfactant water alternative gas (SAG), foam assistant water alternative gas injection (FAWAG), and profile improvement of CO₂ flooding [7,14,34,35]. However, many researchers focus their studies on the flowing property of CO₂ miscible flooding rather than immiscible flooding [16,19]. Moreover, there are few studies on the gas flow law of CO₂ in porous media [11,29,30]. This paper deals with the flowing process of CO₂ immiscible flooding in porous medium, and investigates the influence of injection pressure and injection pressure drop on the gas breakthrough and gas channel. The paper also discusses methods for CO₂ gas channeling control and the improvement of oil displacement efficiency in CO₂ immiscible flooding.

2. Materials and methods

2.1. Materials

Experiments have been carried out using natural outcrop sandstone core sample as a porous media. Its porosity is 20%–23%, permeability is $1.4\text{--}1.7 \times 10^{-3} \mu\text{m}^2$, and its size is $4.5 \text{ cm} \times 4.5 \text{ cm} \times 30 \text{ cm}$. The brine used in all tests is the formation water taken from YanChang oilfield. Brine salinity equals 80.06 g/L. The water type of brine is CaCl₂, and following Table 1 shows the brine ion composition. The crude oil (density 0.8579 g/cm³, degassing viscosity 11.54 mPa s at 45 °C) also came from YanChang oilfield; Table 2 shows the oil composition. In order to simulate the underground viscosity, kerosene with degassed oil has been mixed, obtaining an oil viscosity of 4.87 mPa s (45 °C). The gas phase used in all tests is CO₂ (purity: 99.99%).

2.2. Test equipment and experimental apparatus

Flowing properties and EOR effect in CO₂ flooding have been evaluated using a home-made flooding testing apparatus. Fig. 1 depicts the schematic flow diagram of the flooding testing equipment.

As shown in Fig. 1, a high-precision HSR pump kept the inlet pressure at a constant value (error less than 0.1%) during CO₂ flooding. The gas flow rate was controlled and monitored by gas mass flow controller (flow rate 0–500 mL/min, error < 0.1%) both in the inlet and outlet of core sample holder. A pressure regulator regulated the outlet pressure. The compressed gas controlled the backpressure to make sure that the outlet pressure fluctuations did not exceed 1%. Pressure sensors connected to a computer recorded pressure drop and collected data were stored. All the experiments were conducted in the thermo tank at 45 °C.

2.3. Experimental procedure

The core sample was put into the core holder, and then the tightness of flooding system was checked. A liquid pump has been run for 2 hours to make vacuum, then, the formation water was injected at 0.3 mL/min to fully saturate the core and determine its porosity. When the core was 100% saturated with formation water, the core absolute permeability of water was obtained. To prepare the experiments, oil was injected to the core sample at different injection speeds (0.1 mL/min, 0.3 mL/min, and 0.5 mL/min respectively) to displace the formation water until no traces of water were found in the effluent. Then, one pore volume (PV) of oil was injected to make sure the core sample was fully saturated. To determine the irreducible water saturation and initial oil saturation the cumulative volume of the water was measured. The oil-saturated core sample was placed in the thermo tank for 48 hours, to fully contact the oil with the core porous surface.

Then, the CO₂ gas was continuously injected in the core sample at the constant pressure, and the pressure pump made the pressure at the target value. Moreover, the backpressure was controlled at the design value. The effluent including gas and liquid was collected and separated into oil and gas. Both of them were measured through liquid container and gas flow mass controller, respectively. During the displacement process, the gas breakthrough time and channeling time were recorded. The oil and gas production were also measured to calculate the gas/liquid ratio and oil recovery. The experiments terminated when the gas/liquid ratio at the outlet was more than 3000 m³/m³. Several tests were performed for different injection pressures and pressure drops.

3. Results and discussions

3.1. Gas flowing characteristics

The transport velocity of CO₂ gas in porous media is divided into two parts: transport velocity of gas–liquid two-phase zone frontier (V_d) and transport velocity of gas phase zone frontier (V_g) (Fig. 2). When the gas–liquid two-phase zone frontier is transport to the outlet, the gas

Table 1
Brine ion composition.

Ion	Mass concentration mg/l
Na ⁺ K ⁺	25315.18
Mg ²⁺	496.13
Ca ²⁺	4905.79
Cl [−]	48838.75
SO ₄ ^{2−}	122.47
HCO ₃ [−]	384.81
Total	80063.14

Download English Version:

<https://daneshyari.com/en/article/1747591>

Download Persian Version:

<https://daneshyari.com/article/1747591>

[Daneshyari.com](https://daneshyari.com)