المؤتمر العلمي الدولي الأول للهندسة و العلوم
The First Scientific International Conference in Engineering & Science

http://bwu.edu.ly/icse2022
Received 30/07/2022 Revised 30/12/2022 Published 05/01/2023
icse@bwu.edu.ly ترسل الورقات كاملة علي*

CO_2 INJECTION IN A CARBONATE RESERVOIR FOR EOR PROCESS

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ABSTRACT: CO_2 injection is a mode that is used for enhanced oil recovery (EOR). The residual oil volume is left in porous media after the secondary recovery method of waterflooding operation which can be considered a remarkable and recoverable amount that must be extracted. Therefore, the tertiary recovery mode such as CO_2 injection may be a reliable method for this mission. A carbonate core holder CO_2 flooding trial method has been conducted at reservoir condition to investigate the oil recovery factor. Consequently, three experiments have run in the laboratory with three CO_2 slug sizes that have been injected into the carbonate reservoir after conventional secondary recovery. The results illustrated that oil flow rate increased after each injected CO_2 slug. Firstly, CO_2 slug size of 0.25 PV injected into reservoir which gained a recovery factor of 58.52 % with incremental recovery of 6.78 % over waterflooding process. Secondly, CO_2 slug size of 0.5 PV injected after waterflooding, so, the recovery factor reached up to 61.88 % and the incremental oil recovery was 8.88 %. Finally, the result has shown a significant final oil recovery of 64.49 % and additional recovery factor of 10.75 % when the system carried out CO_2 slug size injection of 1 PV. This might be attributed to good sweep efficiency, capillary force reduction, interfacial tension reduction as well as wettability alteration effectiveness. Consequently, the findings demonstrated that CO_2 displacement process is a remarkable method for EOR project.

Keywords: CO_2 injection, Carbonate reservoir, Oil recovery factor

INTRODUCTION

The oil pools are candidate for enhanced oil recovery (EOR) technique. Too many methods are available for this process such chemical (Honarvar, et. al., 2017; Aluhwal, 2008; Mohr, et. at., 2015; Aluhwal, 2019), steam, microbial, etc. CO_2 is considered an effective agent for enhanced oil recovery. CO_2 single phase flooding mode (Tuzunoglu and Bagci, 2000) substantially enhance oil mainly as a result of the following mechanisms (Al-Abri and Amin, 2010): Firstly, CO_2 may diffuse into crude oil phase and decreases the its viscosity. Secondly, CO_2 diffuses into oil phase cause to increase oil volume (swelling effectiveness) as well as reduces interfacial tension (IFT) between oil and water (Li and yang, 2013; Enayati, 2008). Therefore, the swelling and viscosity reduction are important factors which basically induce the oil through porous media to be recovered in which other enhanced oil recovery techniques is not applicable. A previous research shown that CO_2 can miscible with oil and cause swelling, reduce IFT as well as reduce oil viscosity (Badamchi-Zadeh, et al., 2009; Enayati, 2008; Yazdani and Maini, 2007). The CO_2 injection whether secondary or tertiary recovery method has received substantial attention in the petroleum industry as a result of its remarkable displacement efficiency and relatively not expensive (Stakup, 1978). The main major control mechanisms of CO_2 injection which impact on incremental light as well as heavy oil recovery are swelling effect and oil viscosity reduction. This process discovered in 1930s and had a high evolvement level in 1970s. so, during thirty yeas production work, CO_2 injection became the one of the most important enhanced oil recovery techniques for all types of oil (light, medium, heavy). CO_2 flooding can prolong production period and might increase oil recovery factor up to 25 % of oil initially in place (OIIP) (Yongmao, *et. al.*, 2004). The previous experience of CO_2 flooding operations around oil fields in the world indicted that improved oil recovery by CO_2 gas injection might cause ranging extra oil from 7 to 15 % of original oil in place (OOIP) (Mathiassen, 2003; Enayati, 2008). Furthermore, previous study illustrated that CO_2 flooding technique may cause formation permeability improvement, solution gas flooding and oil and water density change (Enayati, 2008; Yongmao, et. al., 2004). Additionally, this flooding mode may be applicable for sandstone and carbonate formation with different properties of hydrocarbon carrying zone such as thicknesses and permeabilities. The essential factors limit the CO_2 injection are CO_2 availability as well as cost to provide pipelines to bring it to the oil fields (Jessen, et. al., 2001). Several Alberta pools were subjected to the CO_2 flooding. So, the incremental oil recovery reached up to 13 % from the reservoir experience of carbon dioxide injection (Shaw and Bachu 2002; Enayati, 2008). Huazhou Li and his colleagues have reported that CO_2 flooding may enhanced heavy oil recovery where it can swell heavy oil and decrease its viscosity in presence other gases such as C_3H_8 or n-C_4H_{10} (Li, et. al., 2013). CO_2 pure gas added to brine water flooding to improve oil recovery (Aluhwal, et. al., 2017; Fathollahi and Rostami, 2015; Gao, 2015; Aluhwal et. al., 2018). The CO_2 utilization for EOR methods can be CO_2 flooding, CO_2 huff and puff, and CO_2 – water alternating gas injection (WAG) (Zhao et. al., 2021).

1 TRIAL SETUP

1.1 Materials

The obtained grain dolomite rock sample from the laboratory originally contains calcium magnesium carbonate {Ca Mg $(CO_3)_2$} compound. The dolomite sample was packed into the core holder to simulate oil carbonate reservoir properties. In addition, the brine water was made from solution of sodium chloride (NaCl). The crude oil is available in the laboratory. The 99.99% purity of the analytical grade pressurized CO_2 gas was used for enhanced oil recovery process.

1.2 FLOODING SYSTEM

1.2.1 Apparatus

Injection pump: liquid (dual piston pump, model 12-6) is used to flow the mercury throughout stainless steel tubing to the accumulators of crude oil and saline water which are used for core holder injection trial at a particular flow injection rate.

Stainless steel core holder: The used column for injection system is made from grade 316 stainless steel with length of 34.5 cm and diameter of 3.8 cm.

Accumulators: The three accumulators withstand high pressure which one full of crude oil and another one full of saline water to saturate the carbonate reservoir core. The last one is full of CO_2 pure gas.

Backpressure regulator (BPR): The backpressure throughout injection trial regime is dominated by backpressure regulator (BPR) which is set up at outlet of the core holder. The backpressure regulator (BPR) may hold out high pressure till 4000 psi. Furthermore, all the accessories of fittings, BPR, stainless-steel tubes and valves have been purchased from Swagelok company. Figure 1 shows the trial set up assembly.

2 TRIAL METHODOLOGY

The core holder is set in the horizontal level in the oven to simulate oil recovery operations of secondary and tertiary recovery method. Initial oil and water saturations were performed firstly. Secondly, the water flooding method (secondary recovery) followed by the tertiary recovery method of CO_2 injection. Furthermore, the CO_2 injection with various slug sizes of 0.25, 0.5 and 1PV were injected into the core holder at reservoir pressure, temperature and salinity of 2500 psi, 140 °F and 35,000 ppm, respectively.

2.1 Column Preparation

Prior to improve oil recovery, the grain dolomite rock sample of 150 µm size cleaned and dried, the fine grain is quietly inserted and pressed into the core holder while the core holder is continuously shacked. Moreover, distilled water is poured on the grain from the top side of core holder while the vacuum pump is running to pull the water from bottom side of core holder. Additionally, the both core holder sides supported by filter cloth of 5 µm size to forbade grain dolomite migration during displacement process.

2.2 Porosity and Permeability

The completely dried core holder is weight, filled with deionized distilled water and weight again, the different weight is equal to the space volume between grains. According to this rule, the porosity might be determined as next:

Porosity equation estimation as following:

$$\text{Porosity} = \frac{\textbf{DIW volume}}{\textbf{Bulk volume}} \quad (1)$$

The permeability was measured by transport Darcy equation. It is evaluated by the pressure difference between inlet and outlet portions of the core holder at various effluent rates.

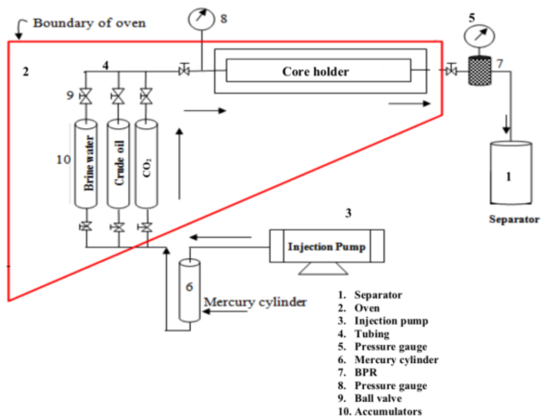

Fig. 1: Schematic diagram of injection system

$$\frac{Q\mu}{A} = K\,\frac{\Delta P}{L} \quad (2)$$

Where, Q is flow rate, µ is viscosity, A is area, ΔP is pressure difference and L is length. Consequently, $\frac{Q\mu}{A}$ is plotted versus $\frac{\Delta P}{L}$. The fitted line which passes the origin point is represent the data. Consequently, permeability constant of core holder is the slope of the straight line. Porosity and permeability data are shown in Table 1.

2.3 Saturation of Reservoir

The core holder is completely filled of artificial saline water, the crude oil is injected into the core holder in order to set up initial water saturation S_{wi} at high pressure and temperature of 2500 psi and 60 °C. The column was left to age at reservoir condition for 100 hours. The both valves at inlet and outlet portions have been completely shut off prolonged aging time.

Table 1. Fluid and grain rock properties

Brine water, viscosity, cp	0.70
38.5° API oil viscosity, cp	2.49
Grain dolomite, K, md	3221
Grain dolomite, Ø, %	40

3 RESULTS AND DISCUSSION

The impact of CO_2 injection on the oil flow rate was assessed at high pressure, temperature and NaCl salinity of 2500 psi, 60 °C and 35,000 ppm, respectively. The procured results shown that there is a substantially improving in cumulative oil production as a result of CO_2 displacement experiment. So, the oil recovery factor shown a remarkable increase during CO_2 injection compared to water flooding process for all CO_2 pore volume injection (Figure 2). Therefore, according to the processing data, the CO_2 slug size injection of 0.25 PV depicted a remarkable positive change in the recovery factor where it reached to 58.52 % with incremental recovery of 6.78 % over waterflooding. Similarly, the CO_2 slug size of 0.50 PV gained a substantial recovery factor of 61.88 % with incremental recovery of 8.88 %. Lastly, the productive of 1 PV CO_2 slug size injection illustrated a markedly recovery factor of 64.49 % and incremental recovery of 10.75 %. Moreover, the residual oil saturations after each experiment run were 32.45 %, 30.34 % and 25.85 % which were left by slug sizes of .25, 0.5 and 1 PV, respectively (Table 2). According to this analysis, the good CO_2 displacement process which reflects changes in rock wettability alteration, reduction of oil viscosity, reduction of interfacial tension (IFT) between oil and water, oil swelling, and appropriate CO_2 displacement efficiency. CO_2 gas can go through small pore space. It replaces the trapped oil and cause to oil flow towards production side. Therefore, all these parameters cause to reduce residual oil saturation. Figure 3 shows the various oil flow rates for all CO_2 slug sizes prolonged trials periods.

Table 2: RF of CO_2 inj. at inj. rate of .5 cc/min

Experiment No.	*1*		*2*		*3*	
Waterflooding	PV_{inj}	RF	PV_{inj}	RF	PV_{inj}	RF
	0.806	51.74	0.864	53	0.697	53.74
	PV_{inj}	RF	PV_{inj}	RF	PV_{inj}	RF
CO_2 flooding	0.25	2	0.50	3.42	1	5.61
Final waterflooding	0.989	4.78	1.308	9.40	1.295	5.14
Total	2.04	58.52	2.683	61.88	3	64.49
Incremental oil recovery	6.78		8.88		10.75	
S_{or}, %	32.45		30.34		25.85	

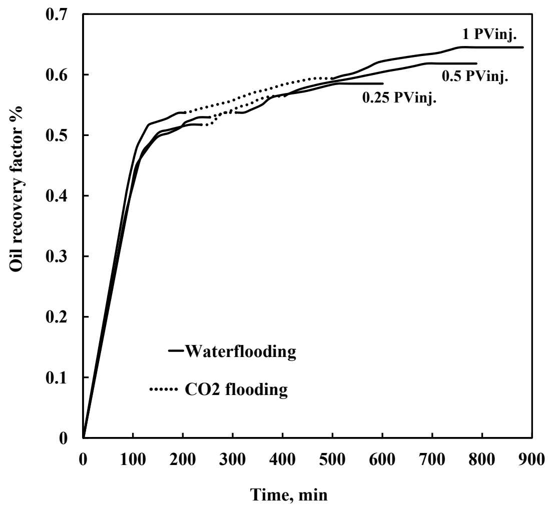

Fig. 2: CO_2 flood in carbonate reservoir

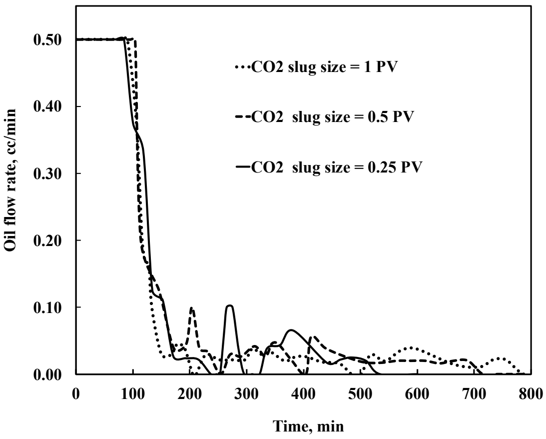

Fig. 3: Oil flow rate during CO_2 flood in carbonate reservoir

CONCLUSION

CO_2 injection can replace the trapped oil in the small pore space and displaces the oil towards production well. The large CO_2 slug size cause to high incremental oil recovery factor. Thus, this process shows a good outcome when the amount of CO_2 increases inside the rock formation.

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