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Performance evaluation of injectivity for water-alternating-CO_2 processes in tight oil formations

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HIGHLIGHTS

- Performance of water-alternating-CO_2 process in tight oil formations is evaluated.
- Fluid injectivity can be improved if CO_2 slug is injected first.
- Displacement experiments in tight oil formations are well history matched.
- Effects of operational parameters on fluid injectivity are examined.

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ABSTRACT

Techniques have been developed to experimentally and numerically evaluate fluid injectivity and oil recovery of water-alternating-CO_2 processes in tight oil formations. Experimentally, core samples collected from tight formations are utilized to conduct a series of water-alternating-CO_2 flooding experiments with different water-alternating-CO_2 ratios and slug sizes. The corresponding oil production, pressure drop, gas production and water production are examined throughout the experiments. Subsequently, numerical simulations are performed to history-match the experimental measurements and conduct sensitivity analysis on operational parameters (i.e., water-alternating-CO_2 ratio, cycle time, and slug size) as well. Compared to waterflooding, fluid injectivity is found to be significantly improved by injecting CO_2 during the water-alternating-CO_2 processes in tight formations. There exists a good agreement between the experimental measurements and simulated results, indicating that the mechanisms governing water-alternating-CO_2 processes in tight oil formations have been well incorporated. It is shown from sensitivity analysis that fluid injectivity is strongly dependent on slug size, water-alternating-CO_2 ratio, and cycle time.

1. Introduction

As world oil consumption escalating and conventional oil reserves depleting, the vast tight oil reserves discovered in North America have attracted more attention recently. The tight oil formations including the Bakken formation, Cardium formation, Niobrara formation, Antelope formation, and Tuscaloosa formation present great recovery potential [1]. However, it is a great challenge to effectively recover oil from such tight formations due to low permeability, though long horizontal wells have been drilled and massively fractured [2]. The conventional waterflooding is not suitable to develop tight oil reservoirs due mainly to extremely low injectivity. Recently, water-alternating-CO_2 flooding has shown favorable recovery efficiency for some tight oil reservoirs [3], though the mechanisms governing fluid injectivity improvement of water-alternating-CO_2 processes in tight oil formation have not been well understood. Therefore, it is of practical and fundamental importance to evaluate fluid injectivity improvement and identify the underlying recovery mechanisms for water-alternating-CO_2 processes in tight oil formations.

Theoretically, fluid injectivity index is defined as the ratio of injection rate to the pressure drop [4], though other variations have been proposed to better describe fluid injectivity in field applications in terms of the injected amount of fluid per unit time,

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unit pressure or unit depth. The injecting schemes, lithology, drilling approach and well treatment condition have been found to affect fluid injectivity during field production processes [5]. As for laboratory experiments, fluid injectivity is mainly controlled by the injecting schemes; while, at same injection rate, a higher pressure drop represents a lower fluid injectivity [6].

In general, mechanisms associated with fluid injectivity improvement during water-alternating-CO_2 processes include carbonate material solubility, oil saturation reduction and retarding clay swelling [7]. Previous efforts have shown that continuous CO_2 flooding is able to improve the fluid injectivity compared to waterflooding in tight oil formations, while the low sweeping efficiency and huge consumption of CO_2 prevents it from being extensively applied in the oilfields [8]. The water-alternating-CO_2 process has shown favorable recovery performance in conventional oil reservoirs for high sweep efficiency, good fluid injectivity and economical consumption of CO_2 [3]. So far, few attempts have been made to evaluate fluid injectivity improvement by water-alternating-CO_2 process in tight oil formations.

In this paper, techniques have been developed to experimentally and numerically evaluate fluid injectivity and oil recovery of water-alternating-CO_2 processes in tight oil formations. Experimentally, three scenarios of coreflooding experiments with varied water-alternating-CO_2 ratios and slug sizes have been performed. Theoretically, a PVT model is built according to the experimental analysis of crude oil, while a displacement model is developed for the given dimension of core samples used in experiments. By tuning the relative permeability curves and capillary pressure curves, numerical simulation is carried out to match the experimental measurements for each scenario. Subsequently, with the tuned models sensitivity analysis are conducted to examine effects of key operational parameters (i.e., water-alternating-CO_2 ratio, slug size and cycle time) on fluid injectivity of miscible water-alternating-CO_2 processes in tight oil formations. Finally, relationships between the operational parameters and fluid injectivity of water-alternating-CO_2 processes are identified, while flooding schemes for water-alternating-CO_2 processes are optimized.

2. Experimental

2.1. Materials

The oil sample and reservoir brine are collected from a tight formation in South Saskatchewan, Canada. The density and viscosity of oil sample are measured to be 801.2 kg/m^3 and 2.17 cP at 20 °C and atmospheric pressure, respectively. The compositional analysis of dead oil sample is tabulated in Table 1. As can be seen, the oil sample mainly contains light or medium components, while the heavy components of C_{30+} only accounts for 11.08 wt%. The minimum miscibility pressure (MMP) of dead oil sample used in experiments is determined to be 9.7 MPa under reservoir temperature of 63 °C with the rising-bubble apparatus by the Saskatchewan Research Council (SRC). The physical properties of reservoir brine are provided in Table 2, allowing us to prepare the synthetic water for the coreflooding experiments.

Table 1
Compositional analysis results of cleaned dead oil.

Component	wt%	Component	wt%	Component	wt%
C_1	0.00	C_8	10.16	C_{20}	2.36
C_2	0.00	C_9	5.79	C_{21}	0.05
C_3	0.13	C_{10}	6.06	C_{22}	4.03
i-C_4	0.14	C_{11}	5.34	C_{23}	1.97
n-C_4	0.56	C_{12}	4.75	C_{24}	1.62
i-C_5	0.34	C_{13}	4.78	C_{25}	1.57
n-C_5	0.56	C_{14}	4.07	C_{26}	1.43
Other C_5	0.05	C_{15}	4.14	C_{27}	1.30
i-C_6	0.43	C_{16}	3.48	C_{28}	1.23
n-C_6	0.42	C_{17}	3.23	C_{29}	0.94
Other C_6	0.47	C_{18}	3.15	C_{30}	0.94
C_7	10.74	C_{19}	2.68	C_{31+}	11.08
				Total	100.00

Tight core samples with permeability lower than 0.5 mD are taken from the tight formations in the same region where oil and brine samples are collected. Research grade CO_2 with purity of 99.998 mol% is purchased from Praxair, Canada.

2.2. Experimental setup

The experimental setup used in this study consists of four subsystems, i.e., injection system, displacement system, production system, and temperature control system (see Fig. 1). In the fluid injection system, synthetic water, oil and CO_2 are stored in transfer cylinders, which are injected into the core samples at a constant rate with a high pressure syringe pump (500 HP, ISCO Inc., USA), respectively. A core sample is placed in the coreholder (Core Lab, USA) with maximum operating pressure of 5500 psi. High pressure nitrogen (Praxair, Canada) is used to supply overburden pressure to the coreholder, which is usually 3.0 MPa higher than the injection pressure. In the production system, a backpressure regulator (BPR) (EBIHP1, Equilibar, USA) is used to maintain the pre-specified production pressure. The produced water and oil are collected by using an oil sample collector, while the gas production is measured by using a gas flow meter (DFM26S, Aalborg, USA). Constant experimental temperature is maintained by using a heater (HG1100, Makita, Canada) and a temperature controller (Diqi-Sense, USA).

2.3. Experimental procedure

Three scenarios of experiments have been designed to examine effects of water-alternating-CO_2 ratios and slug sizes on fluid injectivity. Scenario #1 is conducted with a water-alternating-CO_2 ratio of 1.0, while both water and CO_2 slug sizes are set to be 0.250 PV. Scenario #2 is conducted with a water-alternating-CO_2 ratio of 0.5, while water and CO_2 slug size are 0.125 PV and 0.250 PV in every cycle, respectively. Scenario #3 is conducted with a water-alternating-CO_2 ratio of 0.5, while water slug size is 0.250 PV and CO_2 slug size increases to 0.500 PV.

Prior to each flooding experiment, porosity of a core sample is measured. The core sample is first completely evacuated by using a vacuum pump, followed by injecting the synthetic water. Consequently, porosity can be determined as the ratio of brine volume inside the core sample to its bulk volume. Then the absolute permeability is measured. The synthetic water is injected into the core sample at different rates ranging from 0.1 to 0.5 cc/min, while the corresponding pressure drops are measured. Accordingly, linear regression method is conducted to determine the absolute permeability by applying the Darcy's law with R^2 value higher than 99.9%. The core sample is subsequently flooded with light oil at a constant rate of 0.05 cc/min until irreducible water saturation has been reached. Initial oil saturation is calculated by knowing both volume of the oil injected and pore volume of the core sample. The measured porosity, permeability and initial oil saturation of core samples used in Scenarios #1–3 are listed in Table 3.

As for each scenario, either water or CO_2 is injected at a constant rate of 0.1 cc/min. The production pressure in Scenarios #1–3 is set to be 14.0 MPa in order to maintain the miscible condition throughout the experiments. The pressure drop, cumulative oil production, water production and gas production are measured during each experiment. Once the displacement process is terminated, the blowdown recovery is initiated by decreasing the BPR