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Enhanced heavy oil recovery after solution gas drive by water flooding

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ABSTRACT

Some heavy oil reservoirs in Canada and Venezuela show anomalous behavior under solution gas drive. However, although foamy oil can improve the performance of solution gas drive in heavy oil, only approximately 5–15% OOIP can be recovered during primary production. In this study, micromodel flood experiments and sandpack flood tests were performed to evaluate the potential of water flooding to enhance the recovery of heavy oil after solution gas drive. The micromodel test indicates connected gas channels were created in the micromodel when the pressure was lower than the pseudo-bubblepoint pressure during the solution gas drive; the injected water moves initially through low-viscosity gas channels and through the micromodel during subsequent water flooding. A large number of gas bubbles were found to be dispersed in the oil at the end of the solution gas drive. Heavy oil with dispersed gas bubbles was driven by injected water, forming a flow where water displaced the foamy oil present. The sandpack tests results show that the performance of the subsequent water flooding was significantly affected by the conversion pressure. The conversion pressure was the pressure at the end of the solution gas drive, and the subsequent water flooding was conducted when the pressure was reduced to the conversion pressure after solution gas drive. As the conversion pressure decreasing, the oil recovery of the solution gas drive increased, and the oil recovery of the subsequent water flooding decreased. The optimum conversion pressure of water flooding was found to be the pseudo-bubblepoint pressure. For the water flooding with the convertion pressure lower than the pseudo-bubblepoint pressure, most oil was produced in the high water cut period. Water imbibition caused by capillary forces was the main mechanism leading to the recovery of heavy oil at the high water cut period. The effect of water imbibition on the recovery was more significant at lower injection rate, leading to the higher recovery.

1. Introduction

Heavy oil is an important part of the world's energy supply and is increasingly being exploited as the demand for petroleum increases. There are abundant heavy oil resources around the world, which are estimated between 6.04×10^{11} m^3 and 9.86×10^{11} m^3 in total (Upreti et al., 2007; Li et al., 2011). More than one trillion barrels of heavy oil are located in Canada, Venezuela and Russia. The Orinoco belt in Venezuela is the richest heavy oil deposit in the world with an estimated 500 billion barrels of recoverable heavy oil (Wu et al., 2012). The size of this resource base is immense, but the production of high viscosity crude oil carries its own unique challenges.

Several heavy oil reservoirs in the west Canada, Venezuela, and China under solution gas drive have shown anomalous behavior: high oil production rates, low gas/oil ratio (GOR), and high recovery (Kumar et al., 2002; Hu et al., 2000; Rangriz Shokri and Babadagli, 2012). In these heavy oil reservoirs under solution gas drive, the solution gas is released from the oil to form dispersed gas bubbles inside the oil. Because of this dispersed gas flow, the gas relative permeability are dramatically reduced, and a higher degree of oil swelling is achieved, which contributes to the anomalous primary performance (Pooladi-Darvish and Firoozabadi, 1999; Sheng et al., 1997). The term "foamy oil" is often used to describe this kind of heavy oil, containing dispersed gas bubbles (Bennion et al., 2003; Smith, 1998). However, the recovery from primary production in heavy oil reservoirs is only approximately 5-15% of the original oil in place (OOIP) (Turta et al., 2003).

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Therefore, at the end of primary production, there is still a significant amount of oil-in-place in the reservoir, while the reservoirs have been stripped of their natural energy.

Water flooding is a common and inexpensive secondary oil recovery technique for heavy oil reservoirs; however, limited experience has been reported for water flooding in heavy oil reservoirs. Adams (1982) observed the theoretical behavior of water flooding performance in heavy oil reservoirs in the Lloydminster area of western Canada with oil viscosities of 950–6500 mPa s. Smith (1992) investigated several mechanisms that could recover heavy oil, including pressure support, multi-phase expansion of fluids, water imbibitions and gravity drainage. Miller (2006) published an overview of a relatively small number of significant theoretical and field discussions of Western Canadian heavy oil water flooding available in the public domain to establish the "state of the art" of this field, including proposed production mechanisms, prediction of performance, and improvement of performance. Kumar et al. (2008) presented the results of a comprehensive study to improve the understanding of high-mobility-ratio water flooding and to improve performance prediction; they concluded that the mobility ratio primarily controls oil recovery response and that recovery is lower at higher mobility ratios. Mai and Kantzas (2009) investigated the performance of water flooding in laboratory sand packs for two high viscosity heavy oils at varying water injection rates. They suggested that capillary forces are important even in heavy oil systems; by reducing the injection rate, the significance of capillary forces could be enhanced, allowing more water to access bypassed regions of the porous medium instead of channeling through the water fingers.

However, the performance of water flooding obtained so far primarily focuses on dead (gas-free) heavy oil. Previous studies have considered that gas bubbles were dispersed in heavy oil after solution gas drive, which can influence the flow behavior of subsequent water flooding (Lu et al., 2013; Li et al., 2012). We have preliminary investigated the performances of water flooding, surfactant flooding, gas flooding and foam flooding for enhance the recovery of Orinoco Belt heavy oil after solution gas drive (Lu et al., 2013). Because water flooding is a well-recognized technique for oil recovery after primary production, this study focused on the behaviors of water flooding for enhanced heavy oil recovery after solution gas drive. A micromodel experiment was used to investigate the microscopic flow characteristics of water flooding after solution gas drive; then, the effects of conversion pressure from solution gas drive to subsequent water flooding and water injection rate on the displacement efficiency were investigated in sandpack flood tests.

2. Experimental section

2.1. Fluids

The dead oil used in this study was collected from the MPE-3 block of the Orinoco Belt in Venezuela. The dead oil has a viscosity of 12041 mPa s at 54.0 °C. The mole fractions of MPE-3 block solution gas components are given in Table 1. It can be seen that the primary components of the solution gas are CH_4 and CO_2. To simplify the preparation of solution gas, the gas used in the experiments consisted of CH_4 and CO_2 (provided by Tianyuan Inc., China, with a purity of 99.99%), and mole fractions were 87% and 13%, respectively.

Table 1
mol fractions of MPE-3 block solution gas components.

CO_2%	N_2%	C_1%	C_2%	C_3%	C_4%	C_5%	C_6–C_{10}%
10.82	0.52	86.72	0.31	0.17	0.15	0.13	1.18

Live oil was prepared in a recombination vessel at 54.0 °C, in which dead oil and gas were mixed for several days until the pressure in the vessel stabilized at the desired bubblepoint pressure. The bubblepoint pressure of the synthetic live oil was 6.0 MPa, and the solution gas oil ration (GOR) was 18 m^3/m^3. The properties of the synthetic live oil and the live oil from the MP3-3 block are listed in Table 2. The results show that the differences between the synthetic live oil and the live oil from MP3-3 block are small, indicating that the synthetic live oil can be used in these experiments.

2.2. Micromodel flood experiments

The schematic diagram of the micromodel test is depicted in Fig. 1. A backpressure regulator (BPR) with a pressure accuracy of 0.001 MPa was used to control the backpressure. A high-pressure visual cell allowed an overburden pressure of up to 10.0 MPa, and a temperature up to 180 °C. The confinement fluid in the visual cell was water. The visual cell had two transparent windows: an upper one for viewing the micromodel, and a lower one for illuminating it. A heating muff outside of the visual cell was used to heat the cell to a certain high temperature. A quarter 5-spot glass-etched micromodel was placed in the high-pressure visual cell, as shown in Fig. 2. The micromodel was made of two high pressure-resisting glasses. The lower plate had two holes to inject and retrieve fluids. The micromodel was constructed by etching a two-dimensional network of pores and throats using a photochemical method. The pore network used in this study was patterned based on the pore structure of a core obtained from the reservoir. The depth and width of the microscopic channel were approximately 40 μm. A Nikon Model L110 digital camera was used to record images within the micromodel. An ISCO pump (model 100 DX) delivered live oil to the micromodel at a preset and constant flow rate.

The micromodel test was subjected to solution gas drive with subsequent water flooding following these procedures: (1) the micromodel was subjected to a vacuum using a vacuum pump; (2) the micromodel was saturated with deionized water; (3) the micromodel was displaced by live oil with a back pressure of 6.5 MPa until no water was produced; (4) the inlet of the micromodel was closed, and the back pressure was decreased at a depletion rate of 10 kPa/min; and (5) water was injected at 0.004 mL/min at the end of the solution gas drive. To facilitate the visual observation of the phenomena during water flooding, 0.1 wt% eosin-Y (Sinopharm Chemical Reagent Co., Ltd) was added to color the water. Using a video recorder and camera apparatus, the micromodel test was visualized during different stages of water injection. The test was conducted at the reservoir temperature (54 °C).

The gas bubble textures at different pressures during solution gas drive were determined using image analysis. The original color images were first converted to gray scale intensity images with scale adjustment to enhance contrast in the bubble boundaries. Binary images were then obtained by setting the intensity of the images to an appropriate threshold level. The threshold level is critical for identifying bubbles and was thus was determined interactively by comparing the intensity images with the resulting binary images such that the bubbles in the images were completely separated from each other. The isolated bubbles were identified and labeled by a labeling algorithm with their associated binary image. The number of bubbles was easily determined by counting all labeled objects, and the size of each individual bubble in the 2-D views was given by the number of pixels associated with the corresponding labeled object. Finally, the size of the 2-D bubbles was converted into the diameters of equivalent un-