Journal of Natural Gas Science and Engineering 38 (2017) 195–202

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

journal homepage: www.elsevier.com/locate/jngse

A comparative experimental study of gas injection in shale plugs by flooding and huff-n-puff processes

Yang Yu, Lei Li, James J. Sheng*

Bob L. Herd Department of Petroleum Engineering, Texas Tech University, Lubbock, TX 79409, United States

A R T I C L E I N F O

Article history:
Received 18 August 2016
Received in revised form
13 December 2016
Accepted 26 December 2016
Available online 28 December 2016

Keywords:
Gas flooding
Gas huff-n-puff
Improved oil recovery
Shale reservoirs
Shale oil

A B S T R A C T

The increase in U.S crude oil over the past decade have been primarily driven by tight and shale oil. With the high production decline rates in shale reservoirs, improved oil recovery techniques must be applied to maintain the oil recovery from existing wells. Gas injection has been investigated and demonstrated as the most effective solution to face such challenge. As gas can be injected into the subsurface by two modes: continuous injection (flooding) and cyclic injection (huff-n-puff), this study aims to compare the recovery efficiencies of such two processes in shale core plugs with ultra-low matrix permeability.

Eagle Ford core samples were used in this study and saturated with shale oil. Using N_2 as the gas source, gas injection tests were operated on the same plug orderly by both modes under the same operating conditions. The sensitivity of soaking time on the huff-n-puff performance was evaluated. Lab-scale numerical models were built to simulate flooding and huff-n-puff processes and to history match the experimental data. It was found that optimization design of huff-n-puff is important to achieve the maximum oil recovery. The results show that the huff-n-puff possess can achieve a higher oil recovery than the flooding process.

1. Introduction

In the following decades, U.S tight and shale oil production will remain stable and keep growing gradually. As Fig. 1 shows, although the tight oil production fell to 4.1 million b/d in June 2016 (EIA, 2016a), the U.S. tight oil is expected to increase from 4.2 million b/d in 2017 to 7.1 million b/d in 2040 in the AEO2016 Reference case (EIA, 2016b). The horizontal wells drilled in shale formations usually begin producing at very high rates, then they fall off very sharply, and finally they level off at a much lower rate (Ma, 2015; Yu and Wood, 2015). The improving fracturing technology contributes to the shale oil recovery. Yuan et al. (2016) proposed an integrated approach to evaluate the efficiency of fracturing stimulation and predict well production performance, by which the ultimate recovery, optimal fracture spacing, and the horizontal section length can be obtained. However, the sustainable development of shale reservoirs and improving the oil recovery is becoming a new challenge. Operators also show rising interest in maximizing shale oil production. In order to extend the productive life of existing wells, improved oil recovery (IOR) techniques must be applied to tight and shale reservoirs after the primary depletion as well as during the high declines rates period. Through analyzing the test results from IOR pilot projects by injecting gas or water in the Bakken formation, Hoffman and Evans (2016) proposed the feasibility of injection fluids into very low permeability reservoirs, but the major issue is conformance control that the projects show early breakthrough times and poor sweep efficiencies. In order to achieve more than 20% of recovery factors in unconventional reservoirs, they emphasized the necessity of IOR techniques and the significance of developing effective injection fluid and injection methods.

Gas injection is a developed and successful IOR technique for recovering oil from conventional reservoirs. It has been demonstrated as most effective and promising IOR method in shale reservoirs by many recent publications (Dong and Hoffman, 2013; Yu et al., 2014; Sheng and Chen, 2014; Zhu et al., 2015; Kong et al., 2016). Generally, gas can be injected into the reservoir in two modes: continuous flooding and huff-n-puff injection, while both have their own advantages and limitations. For the well-to-well flooding process, the gas is continuously injected to the reservoir formation to displace the residual oil to adjacent production wells. The huff-n-puff injection process is related to a single-well that the

* Corresponding author.
E-mail address: james.sheng@ttu.edu (J.J. Sheng).

http://dx.doi.org/10.1016/j.jngse.2016.12.040
1875-5100/

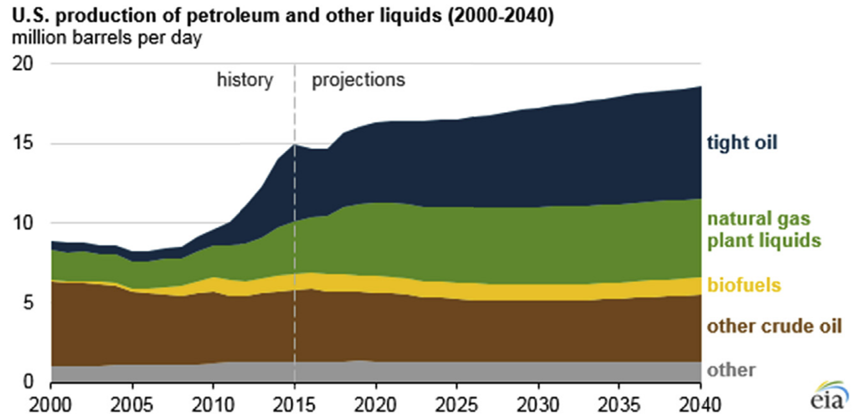

Fig. 1. Projection of U.S. petroleum and other liquid fuels production.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2016* Reference case

gas is cyclically injected into the reservoir. Each cycle involves three phases: reservoir pressure build-up (huff), pressure equilibration and fluids interaction (soaking), and pressure depletion for production (puff).

There have been some reservoir simulation studies that evaluated and compared the recovery performances between such two processes in shale plays (Song and Yang, 2013; Wan et al., 2014; Wan and Sheng, 2015a). Experimentally, our research team have evaluated the IOR potential of gas huff-n-puff process and gas flooding process using shale plugs separately. Gamadi et al. (2013) investigated the recovery performance of cyclic N_2 injection process in fractured shale reservoirs. Various types of shale outcrop plugs were used (Barnett, Marcos, and Eagle Ford) and saturated with mineral oil (Soltrol 130). They examined the effects of soaking time and injection pressure on the recovery efficiency. Results demonstrated the recovery potential of N_2 cyclic injection process in shale oil reservoirs, with RFs from 10% to 50% depending upon the operating conditions and core type. They also investigated the recovery performance of CO_2 cyclic injection in the following study (Gamadi et al., 2014). Miscible CO_2 injection had a positive influence on RF compared to immiscible injection. The effect of soaking period in the cyclic injection process was highlighted because the shale plugs have ultra-low matrix permeability, so a longer soaking time gives a higher ultimate RF. Yu et al. (2016a,b) further discussed the roles of soaking time and pressure depletion rate in gas huff-n-puff process in fractured shale reservoirs. Applying methane as the gas source, Li et al. (2015) conducted the upscale study on evaluating the gas huff-n-puff recovery efficiency in shale plays. As the operation of huff-n-puff process involves many sensitive parameters which can greatly affect the recovery performance, Li et al. (2016) also performed the optimization design of gas huff-n-puff in shale reservoirs to enhance oil recovery. For the gas flooding study, Yu et al. (2016b) investigated the effects of injection pressure and recovery period on the shale oil recovery. More literature information can be found in Sheng, 2015. From the simulation results and laboratory observations, the huff-n-puff process presented outstanding recovery performance. However, limited experimental work has been conducted to compare the efficiencies of two displacement processes under the same operating conditions.

This study aims to compare the recovery performances of gas flooding and gas huff-n-puff in shale core plugs. The two injection modes were performed under the same injection pressure and operation period to recover oil from Eagle Ford core samples with matrix permeability in the nano-Darcy range. In addition, lab-scale simulation models were built to history match the experimental data and to explore the recovery characteristics of such two injection processes.

2. Experimental work

2.1. Materials

Two shale core plugs were used in this study. They were cut from different locations of the Eagle Ford outcrop, thus presented different properties of porosity and permeability. Table 1 gives the plug dimensions and properties. Oil sample was dead oil from Wolfcamp shale play with the density of 0.815 g/cm^3 and viscosity of 8.5 cp, which were measured at the temperature of 72 °F and atmospheric pressure. Nitrogen gas with the purity of 99.999% was used as the displacement medium in gas injection tests.

2.2. Experimental setup and design

Core samples were saturated with oil followed by performing gas injection tests. For the saturation process, the core plug was placed in an oven for drying 1 day and weighted (W_{dry}). Subsequently, it was placed in a vessel and vacuumed for 1 day. After that, using a displacement pump (QX-6000), the oil was delivered into the vessel under a constant pressure of 1000 psi for 1 day for maximum saturation. Then, the core was removed from oil and weighted (W_{sat}) after a few hours to stabilize the weight and equilibrate the matrix pressure. The detailed setup, operation procedures of core saturation, and data uncertainty analysis for individual test can be referred to our previous paper (Yu et al., 2016a,b) and Yu's dissertation (Yu, 2016).

The experimental setup for N_2 flooding and N_2 huff-n-puff are shown in Fig. 2. To minimize experimental errors and diminish the effect of sample difference on results, same plug was used to perform both modes of gas injection recovery processes. Table 2 presents the operating parameters. Two core samples, CEF_1 and CEF_2, were used to operate the gas injection tests for a total operation period of 2-day and 3-day, respectively. For all tests, the injection pressure was 1000 psi, and the confining pressure was 500 psi higher than the injection pressure. The production pressure was set as atmospheric pressure. As the temperature effect on recovery factor (RF) was not the focus in this study and for the convenience of operation, all tests were operated at the room

Table 1
Core plug properties.

Core No.	Diameter (mm)	Length (mm)	Dry weight (g)	Saturation Porosity	Average Permeability (nD)
CEF_1	38.5	50.9	152.099	4.4%	85
CEF_2	38.1	101.8	249.697	13.1%	400