Journal of Natural Gas Science and Engineering 28 (2016) 46–51

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

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

Potential to increase condensate oil production by huff-n-puff gas injection in a shale condensate reservoir

James J. Sheng [a,*], Fersheed Mody [b], Paul J. Griffith [b], Warren N. Barnes [b]

[a] Texas Tech University, United States
[b] Apache Corporation, United States

ARTICLE INFO

Article history:
Received 16 October 2015
Received in revised form
14 November 2015
Accepted 15 November 2015
Available online 22 November 2015

Keywords:
Huff-n-puff
Gas condensate
Liquid drop out
Gas injection
shale reservoirs
Unconventional

ABSTRACT

This paper presents a huff-n-puff gas injection method to increase condensate production in an Eagle Ford gas condensate reservoir using a simulation approach. The simulation study suggests that the huff time and puff time should be the same. Because of higher compressibility of a gas condensate fluid, either huff or puff time required will be longer than that for a shale oil reservoir. For the studied reservoir, an optimum huff or puff time is about 600 days. However, a shorter time of 300 days is preferable for recouping the cost for facilities. To improve the overall liquid condensate recovery performance, during the last half of the development period, the huff-n-puff may be changed to pressure depletion so that the energy injected earlier can be fully utilized. Other effects such as those of initial water saturation, injection pressure, and gas composition, are also investigated in this paper. The methodology presented in this paper is applicable to other gas condensate reservoirs, and some of results or conclusions may be typical of gas condensate reservoirs.

1. Introduction

In a gas condensate reservoir, when the pressure is decreased below the upper dew point, liquid condensate forms. Even when the overall reservoir pressure is above the dew point, most often, the pressure near a producer will be below the dew point. Thus, liquid condensate will accumulate near the wellbore. The liquid condensate blocks gas flow, reducing the gas production rate. Thus, less liquid oil can be obtained at the surface (Thomas et al., 1995). Bang et al. (2008) found that condensate buildup in the fractures can significantly reduce the productivity of fractured wells. The steady-state relative permeability even in propped fractures is typically on the order of 0.1. When oil saturation is below a residual oil saturation, oil cannot be produced using a conventional production method. To solve this problem, several techniques have been used, including gas cycling, drilling horizontal wells, hydraulic fracturing, injection of super-critical CO_2, use of surfactant, use of solvents and the use of wettability alteration chemicals. Gas cycling is to keep the reservoir pressure above the dew-point pressure. Drilling horizontal wells and hydraulic fracturing are to reduce the pressure drop. Injection of super-critical CO_2 is to reduce the dew-point pressure (Uchenna, 2012). Use of surfactant is to reduce interfacial tension or alter wettability so that the capillary number is increased and the well productivity is increased (Kumar et al., 2006; Ahmadi et al., 2011). One common practice in conventional reservoirs is to maintain the reservoir pressure or even the bottom-hole well pressure of the production well above the dew point pressure by gas and/or water flooding (Hernandez et al., 1999). Use of chemical stimulation to alter the wettability to non-liquid wetting to remediate the blocking problem was proposed by Kumar et al. (2006), Ahmadi et al. (2011), and Ganjdanesh et al. (2015). Use of solvents to mitigate the impact of liquid blockage has shown positive treatment outcomes in conventional gas condensate reservoirs (Al-Anazi et al., 2005; Sayed and Al-Munstasheri, 2014). Recently, Meng et al. (2015) have verified in the laboratory that huff-n-puff gas injection can enhance liquid oil production in shale gas condensate cores.

This paper is to investigate the potential of huff-n-puff gas injection to increase liquid oil production in an Eagle Ford gas-condensate reservoir using a simulation approach.

2. Setup of a base simulation model

The current technology to develop shale resources uses horizontal wells with multistage fracturing. To conduct a simulation

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

http://dx.doi.org/10.1016/j.jngse.2015.11.031
1875-5100/

study, we need to build a model including this technology, and this model needs to be validated. Several authors (Kurtoglu, 2013; Yu et al., 2014) have built models using the Middle Bakken data, but their detailed models are not publically available, and there are no data in the literature that are more complete than the Bakken data. Thus, we will use the Bakken data to build a base model.

In this paper, the compositional simulator, GEM, developed by Computer Modeling Group (CMG) (2014), is used. Because of flow symmetry, a half-fracture connected through a vertical well is simulated. In the Middle Bakken case, a horizontal well is fractured with 15 fracturing stages. It is assumed that only one fracture is generated at one stage, so the production data from this model represents one-thirtieth of the actual production.

The simulation model (reservoir volume) includes two regions: the stimulated reservoir volume and the un-stimulated reservoir volume. The schematic is shown in Fig. 1. The model area is 296.25 ft wide in the I direction, 4724 ft in the J direction with 724 ft in the SRV area, and 50 ft in the K direction (not shown in the figure). In this model, the half-fracture spacing is 296.25 ft in the I direction, the fracture length is 724 ft in the J direction, and the fracture height is 50 ft in the K direction. The half-hydraulic fracture width is 0.5 ft. One block is used in the K direction of 50 feet.

In this paper, we tried to use the data of the Middle Bakken formation presented by Kurtoglu (2013). Table 1 summarizes the input matrix and fracture properties in the Non-SRV and SRV regions in the Middle Bakken shale. The dual permeability model is used to simulate the naturally and hydraulically fractured shale reservoirs. The shale matrix permeability is 0.0003 mD. The natural fracture effective permeability in the SRV is 0.0313 mD. The natural fracture permeability in the un-stimulated reservoir region is 0.00216 mD; that is much lower than the stimulated region.

The reservoir fluid composition, the Peng-Robinson EOS parameters, and relative permeabilities are from Yu et al. (2014). Use these data and parameters, 1.2 years of production history is able to be matched. During the history-match,, the stock-tank oil rate is imposed and the effort is made to match the well bottom-hole pressure. Fig. 2 compares the simulated well bottom-hole pressure (line) with the actual data (dotted points). It can be seen that the well bottom-hole pressure is reasonably matched.

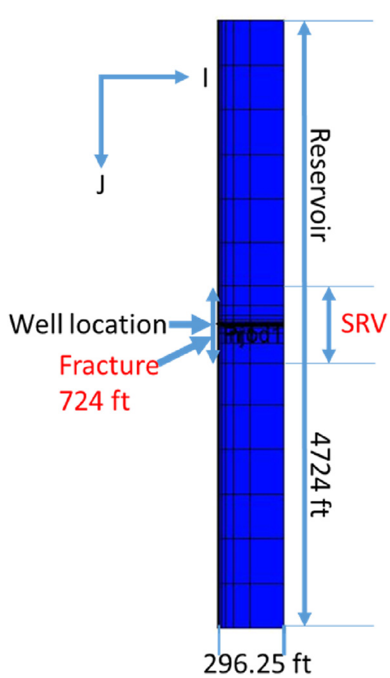

Fig. 1. Schematic of the base model.

Table 1
Matrix and fracture properties.

	Non-SRV	SRV
Thickness, ft	50	50
Matrix Permeability, mD	3.0E-04	3.0E-04
Matrix Porosity, fraction	0.056	0.056
Fracture Porosity, fraction	0.0022	0.0056
Fracture Permeability, mD	2.16E-03	3.13E-02
Fracture Spacing, ft	2.27	0.77
Hydraulic fracture porosity, fraction		0.9
Hydraulic fracture permeability, mD		100

Next, the above calibrated, hydraulically fractured model is used to conduct a simulation study of gas condensate recovery in this paper. The grids, reservoir rock properties, matrix and fracture properties, etc. are unchanged. But gas condensate properties and some of reservoir properties for a gas condensate reservoir in the Eagle Ford formation are used in the model as described next.

For this gas condensate reservoir, the initial reservoir pressure is 9985 psig, the measured upper dew point pressure is 4184 psig, and the reservoir temperature is 270 °F. The reservoir fluid composition and the Peng-Robinson EOS parameters are presented in Table 2, and the binary interaction coefficients are shown in Table 3. In Table 2, P_c, T_c and V_c are critical pressure, critical temperature and critical volume, respectively, and MW is molecular weight.

The values of the above tables are obtained by regression to match relative volumes (Fig. 3) and liquid dropouts during a constant composition expansion test (Fig. 4) at different pressures. The experimental data were measured by a service company.

3. Simulation results and discussion

The reference case is the primary depletion. The reservoir is produced for 10,950 days (30 years). The maximum gas production rate is 300 MSCF/day for a half fracture that is equivalent to 9 MMSCF/day for the whole horizontal well. The minimum bottom-hole pressure is 500 psi. The oil recovery after 30 years is 28.195%, and the gas recovery is 66.164%. Next, we will investigate the effects of huff and puff time, the combination of huff-n-puff and pressure depletion, initial water saturation, and gas composition. Before any huff-n-puff injection, 1800 days of primary depletion is carried out. At the end of this primary depletion, the average reservoir pressure becomes 4065 psi and the well bottom-hole-pressure is 513 psi.

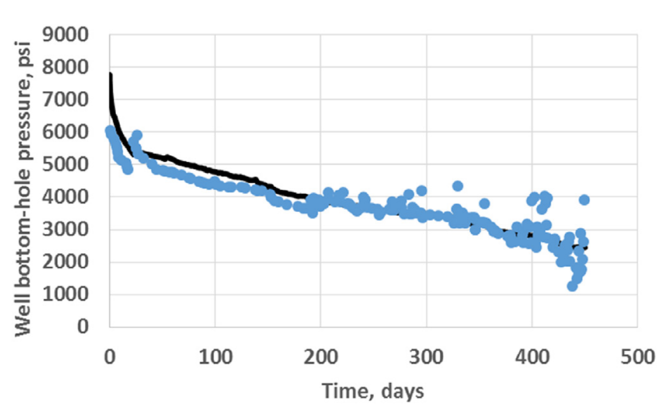

Fig. 2. Well bottom-hole pressure (dot points are actual data, and line is simulated data).