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A comparative study of flowback rate and pressure transient behavior in multifractured horizontal wells completed in tight gas and oil reservoirs

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ABSTRACT

Tight reservoirs stimulated by multistage hydraulic fracturing are commonly characterized by analyzing the hydrocarbon production data. However, analyzing the available hydrocarbon production data can best be applied to estimate the effective fracture–matrix interface, and is not enough for a full characterization of the induced hydraulic fractures. Before putting the well on flowback, the induced fractures are filled with the compressed fracturing fluid. Therefore, analyzing the early-time rate and pressure of fracturing water and gas/oil should in principle be able to partly characterize the induced fractures, and complement the conventional production data analysis.

We construct basic diagnostic plots by using two-phase flowback data of three multifractured horizontal wells to understand the physics of flowback. Analysis of flow rate plots suggests three separate flowback regions based on the relative values of water and gas/oil flow rate. In the first region, water production dominates while in the third region gas/oil production dominates. In the second region, water production drops and gas/oil production ramps up. The cumulative water production (CWP) plots show two distinct water recovery periods. Before gas/oil breakthrough, CWP linearly increases with time. After breakthrough, CWP increases with a slower rate, and reaches to a plateau for the oil well. We also develop a simple analytical model to compare the pressure/rate transient behavior of the three flowback cases. This work demonstrates that rate and pressure, carefully measured during the flowback operations, can be interpreted to evaluate the fracturing operations and to complement the conventional production data analysis for a more comprehensive fracture characterization.

1. Introduction

The amount of hydrocarbon stored in previously inaccessible shale and tight reservoirs is significantly higher than that stored in conventional reservoirs (Zahid et al., 2007; Abdelaziz et al., 2011). Recent advances in horizontal drilling and multistage hydraulic fracturing have unlocked these challenging hydrocarbon plays. Characterizing the induced fracture network is important for evaluating the fracturing operation, and predicting the reservoir performance. Various mathematical models have been proposed for analyzing the hydrocarbon production data for the purpose of characterizing the fractured horizontal wells. The fracture–matrix interface and fracture half-length are usually determined by analyzing the hydrocarbon production data. The dual porosity model has been extended for analyzing the fractured horizontal wells (Bello, 2009; El-Banbi, 1998; Medeiros et al., 2008, 2010; Ozkan et al., 2010). The available hydrocarbon production data mainly match the late linear transient part of the type curves, which relates to the fluid transfer from the matrix into the fracture. This match can be interpreted to determine the effective fracture half-length. However, a full characterization of the fracture network by only analyzing the hydrocarbon data is challenging because:

- The early-time oil or gas production data is usually unavailable or of low quality for history matching.
- The induced fracture network is initially filled with compressed fracturing fluid not hydrocarbon. Therefore, analyzing the hydrocarbon data for determining the fracture storage capacity can be misleading.

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◦ Production data analysis does not account for the fractures, which are filled with water and do not contribute to the hydrocarbon flow.

Conventional rate transient methods have been applied for analyzing the flowback data. For example, the reciprocal productivity index method has been applied on the early time flowback data to evaluate the stimulated vertical gas wells (Crafton, 1996, 1997, 1998). However, application of this approach for analyzing the flowback data of fractured horizontal wells needs further modifications. Ilk et al. (2010a,b) introduced a workflow for a qualitative interpretation of early time flowback data by developing various diagnostic plots to observe wellbore unloading and fracture clean-up/depletion trends. Clarkson (2012) presented a quantitative analysis of two-phase flowback data using a two-phase tank model simulator to estimate fracture permeability and total fracture half length. Later, Clarkson's model was improved by applying Monte Carlo simulation for stochastic history matching of two-phase flowback data measured after multistage hydraulic fracturing (Williams-Kovacs and Clarkson, 2013). In addition to rate transient models, compositional simulators have been developed to history-matching flowback salt concentration change (Gdanski et al., 2007).

This paper aims at 1) Qualitative and careful analysis of multiphase flowback data for understanding water displacement patterns, and 2) development of a simple analytical tool for analyzing early-time rate and pressure data. The second objective is achieved by extending the existing models of fracture testing. Various flow and shut-in tests have been proposed for recording the fracture response transferred by the fracturing fluid. Examples include the injection/fall off test (Craig, 2006), the fracture-calibration test (Mayerhofer et al., 1995) and the slug test (Peres et al., 1993). The mathematical models for such tests are developed by solving the material balance equation for fluid transport in the reservoir, fracture, and wellbore. The solutions have been reported in the form of type curves (Craig, 2006). The main out puts of the fracture tests are fracture conductivity and storativity.

The remaining of this paper is organized as follows: Section II qualitatively interprets the rate, pressure, and cumulative production of water and oil/gas recorded during three different flowback operations. Section III develops a simple analytical model to compare the pressure/rate transient behavior of the three flowback cases. Section IV applies the proposed model to the field data and discusses the results. Section V discusses the overall results and summaries the paper.

2. Flowback rate and pressure history

In this section, we interpret flowback rate and pressure history of three multifractured horizontal wells completed in one tight oil and two tight gas reservoirs. Table 1 shows the completion data and fluid properties of the three wells.

Table 1
Completion data and fluid properties of three wells.

Given parameters	Well 1	Well 2	Well 3
Hydrocarbon type	Gas	Gas	Oil
Fracturing fluid	Water	Water	Water
Distance between fracture stages (L_f), ft	242.78	91.86	236.22
Horizontal well length (X_e), ft	4593.17	1312.33	4265.09
Number of fracture stages (N_f)	20	15	20
Total compressibility (c_t), psi^{-1}	2.850 e^{-4}	2.871e^{-4}	2.901e^{-4}
Water compressibility (c_w), psi^{-1}	3.333e^{-6}	3.333e^{-6}	3.333e^{-6}
Viscosity of fracturing fluid (μ), cp	0.331	0.331	0.331
Water formation volume factor (B_w),	1.0311	1.0290	1.0003
Wellbore radius (r_w), ft	0.2916	0.2998	0.2874

2.1. Well 1

This well is completed in a tight gas reservoir. Initially, the well was flowed back with variable choke sizes for couple of hours. Then, two different choke sizes of 19.05 mm and 38.10 mm were used for almost 24 h and 48 h, respectively.

2.1.1. Flowback history

Fig. 1(a) shows the flow rate and pressure measured at the surface during the flowback of well 1. Casing pressure is initially high and quickly drops with time. The rate plot is divided into three regions. In the first region, $q_g = 0$ and only water flows with a rate specified by the choke size. In the second region, gas production starts and q_w gradually decreases. In the third region, $q_w \approx 0$ and mainly gas is produced.

Fig. 1(b) compares the cumulative water production and gas production versus cumulative time. Cumulative water production curve shows two distinct regions. The first region is denoted by a black dashed line which shows a steep increase in water production for about 25 h and is named Early Water Production (EWP) region. The second region shows the gradual increase in water production until the end of flowback operation and is named Late Water Production (LWP) region. During EWP, water flow rate (determined by the curve slope) remains relatively high. During LWP, water flow rate decreases gradually. Faster initial water production rate can be explained by two reasons: 1) Water saturation and in turn, water relative permeability in fractures is initially high and drops with time as gas is introduced from the matrix into the fractures. 2) Initially conductive primary fractures contribute to water production, followed by secondary fractures with a relatively less conductivity. The gas production curve, in Fig. 1 (b), shows that gas breaks through almost 5 h after opening the well, and cumulative production gradually increases. This indicates gradual gas saturation increase or water saturation drop that was discussed above.

Table 2 lists the relative volumes of water recovered during the flowback of this well. The total injected volume (TIV) is 1501 m^3. After 86 h of flowback, the total load recovery (TLR) is 329.64 m^3, which is only 21.96% of TIV. During EWP, 261 m^3 of water is produced which is about 79.17% of TLR and the remaining 20.83% is recovered during LWP. The wellbore volume (WV) is 92.042 m^3, which is initially filled with water and contributes to 27.92% of TLR.

2.2. Well 2

This well is completed in a tight gas reservoir. Initially, the well was flowed back with five choke sizes for 16 h. Then a choke size of 19.05 mm was used for 100 h.

2.2.1. Flowback history

Fig. 2(a) shows the flow rate and pressure measured at the surface during the flowback of Well 2. Tubing pressure is initially high and quickly drops with time. Several peaks followed by decline behaviors are observed in the pressure plot, which indicate that this well has been shut-in several times after starting the flowback operation. The rate and pressure plot is divided into three regions. In the first region, q_g is relatively low and water production dominates with a rate specified by the choke size. In the second region, gas flow rate ramps up and q_w gradually decreases in different steps, which are specified by the choke size. In the third region, q_w is relatively low and gas production dominates.

Fig. 2(b) compares the cumulative water and gas production versus time. Similar to well 1, the cumulative water production curve here shows two distinct regions. The first region (EWP) is denoted by a black dashed line which shows a steep increase in water production for about 24 h. The second region (LWP) shows a