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Liquid uptake of gas shales: A workflow to estimate water loss during shut-in periods after fracturing operations

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ABSTRACT

The imbibition of fracturing fluid into the shale matrix is identified as one of the possible mechanisms leading to high volumes of water loss to the formation in hydraulically fractured shale reservoirs. In an earlier study (Makhanov et al, 2012), several spontaneous imbibition experiments were conducted using actual shale core samples collected from Fort Simpson, Muskwa and Otter Park formations, all belonging to the Horn River shale basin. This study provides additional experimental data on how imbibition rate depends on type and concentration of salt, surfactants, viscosifiers and sample orientation with regard to the bedding plane. The study also proposes and applies a simple methodology to scale up the laboratory data for field-scale predictions.

The data show that an anionic surfactant reduces the imbibition rate due to the surface tension reduction. The imbibition rate is even further reduced when KCl salt is added to the surfactant solution. Surprisingly, viscous XG solutions show a considerable spontaneous imbibition rate when exposed to organic shales, although their viscosity is much higher than water viscosity. This observation indicates that water uptake of clay-rich organic shales is mainly controlled through preferential adsorption of water molecules by the clay particles, and high bulk viscosity of the polymer solution can only partly reduce the rate of water uptake.

The field scale calculations show that water loss due to the spontaneous imbibition during the shut-in period is a strong function of fluid/shale properties, fracture-matrix interface, and soaking time. The presented data and analyses can be used to explain why some fractured horizontal wells completed in gas shales show poor water recovery and an immediate gas production after extended shut-in periods.

Introduction

Hydraulic fracturing is a key technology for unlocking hydrocarbon resources from the shale reservoirs, which would have been otherwise stranded (Novlesky et al., 2011). Fracturing fluids enriched with proppants and assorted chemicals are pumped into the formation to create hydraulic fractures. Recent studies show that fractured shale reservoirs retain a significant fraction of injected fluid volume. This fact causes serious economic, technical and environmental concerns (Soeder, 2011; Chapman, 2012). Questions such as how much of fracturing fluid goes into the shale matrix and how much stays in the fracture network are critical for understanding the hydraulic fracturing process in shale formations.

Fig. 1 shows typical load recovery values versus time for 12 multi-fractured horizontal wells completed in the Horn River basin (Abbasi, 2013). The vertical axis shows load recovery in percentage of injected water volume recovered at the surface. The horizontal axis shows the time period of flowback operations. Flowback is the process after the hydraulic fracturing operation when the injected fracturing water is recovered at the surface facilities. Plots demonstrate that a significant portion of fracturing water remains unrecovered and only around 25% of injected water is recovered after nearly 40 days of flowback operations.

There are several reasons causing low recovery of fracturing water. One reason is related to the incomplete water drainage in the propped fractures due to adverse mobility ratio and gravity segregation (Parmar et al., 2013, 2014). The second reason is trapment of water in secondary fractures, which are poorly connected to hydraulic fractures (Fan et al., 2010). The third reason is related to the imbibition process during and after the fracturing operation, which is, partly, responsible for high volumes of water loss in the field (Roychaudhuri et al., 2011; Odusina et al., 2011). Furthermore, vapor-diffusion is another contributing mechanism to increase the water imbibition into the samples in which vapor can be condensed and play an important role especially for the long time contact between fluid and rock (Hu et al., 2001).

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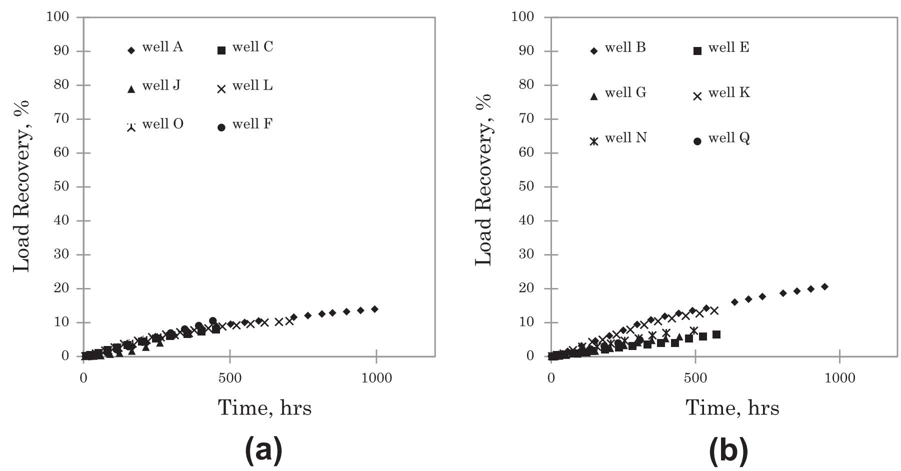

Fig. 1. Typical load recovery values during the flowback operations from multi-fractured wells completed in Muskwa (a) and Otter Park (b) members of the Horn River Basin.

In addition to the water management issues, invasion of the fracturing fluid into the shale matrix may affect natural gas production (Dutta et al., 2012). On one hand, due to the substantial capillary pressure, water imbibes into the matrix pores and prevents counter-current gas flow (Sharma and Agrawal, 2013). On the other hand, imbibing water may generate micro fractures in the formation matrix and/or may release gas from pores due to the counter-current flow (Dehghanpour et al., 2012, 2013). Therefore, understanding of spontaneous imbibition at the field scale is an important task for the shale-gas industry. Recently, Morsy et al. (2013) showed that the degree of water imbibition depends on the type of shale formations.

One of the earliest models for spontaneous imbibition was presented by Handy (Handy, 1960) for water–air systems. In this model, the imbibed volume is proportional to the square root of imbibition time. Some obstacles in flow physics hindered the widespread use of this model. Later, Schembre et al. (1998) derived an expression for imbibition as a function of effective water permeability, water saturation, and capillary pressure of the porous medium.

$$Q_w^2 = \left(\frac{2P_c \varphi K_w S_w A_c^2}{\mu_w} \right) t \quad (1)$$

where, Q_w is volume of water imbibed, t is time, A_c is contact surface area, P_c is capillary pressure of porous medium, φ is porosity and μ_w, K_w and S_w are viscosity, effective permeability and saturation of water, respectively.

In this paper, we provide results from additional experimental work, and provide a simple analytical procedure to estimate the amount of water loss during the soaking time by using the laboratory data. Interpretation of the experimental results together with field data can help to improve our understanding of water loss during and after hydraulic fracturing operations.

Materials and methods

Spontaneous imbibition experiments were conducted using specially prepared shale samples and test fluids to measure the imbibed volume versus time. Effects of the base fluid type (aqueous) with the additives (salt, polymer, and surfactant) on the rate of fluid intake into shales were investigated. The following section briefly describes the materials, and experimental set-up and procedures for the imbibition tests. The results are presented in terms of volume of fluids imbibed versus square root of time. The detailed description of experimental program and results are described elsewhere Makhanov et al., 2012.

Imbibing fluids

In total, eight different aqueous fluids at pH 7 with different levels of salinity, surface tension and viscosity were used as imbibing fluids:

- Fresh water (DI).
- 2 wt.% KCl brine (KCL).
- Anionic surfactant in fresh water (DI + DDBS).
- Non-ionic surfactant in fresh water (DI + Terg).
- Anionic surfactant in 2 wt.% KCl brine water (KCL + DDBS).
- Non-ionic surfactant in 2 wt.% KCl brine (KCL + Terg).
- Xanthan Gum polymer solution with concentration of 0.28 wt.% (XG 0.28 wt.%).
- Xanthan Gum polymer solution with concentration of 0.56 wt.% (XG 0.56 wt.%).

It is worthy to mention that investigation of solution pH is not the subject of this study.

Shale samples

We used 32 shale samples in the experiments. The samples represent shale formations including Fort Simpson, Muskwa (Upper zone and Middle zone) and Otter Park, which are all stratigraphic units of the Horn River Basin. The size of samples differed with each other as it is depicted in Fig. 2. To normalize and compare the obtained results of experiments, volume of imbibed water into rock samples is divided by the cross sectional area open to flow. Therefore, the effect of size variation on experimental results can be rectified by this normalization. Samples are coated using impermeable epoxy, so that the fluid could imbibe only through one designated surface. The surface open to the fluid imbibition is positioned orthogonal to the bedding plane (lamination), where imbibing fluids dominantly move along the lamination. It should be noted that the imbibition rate along the lamination direction is higher than that perpendicular to the lamination, which will be discussed in the following sections. Example pictures of the samples used in the experiments are shown in Fig. 2.

Physical properties of rock samples and imbibing fluids and mineralogical properties of rock samples on the basis of XRD analysis are presented in Table 1 and Table 2, respectively.

Experimental set-up

An experimental set-up, schematically illustrated in Fig. 3, was designed to measure the change in sample weight as a function of