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Experimental investigation of the effect of imbibition on shale permeability during hydraulic fracturing

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A B S T R A C T

Hydraulic fracturing technology is widely applied in shale reservoirs to significantly increase production. However, when many operators report a large percentage of the fracturing fluid is not recovered, it is unclear how the remaining fracturing fluid affects the shale formation. It is believed that the unrecovered fracturing fluid could be imbibed by shale matrix, micro-fractures, and surfaces of fractures that are already separated. This paper is to investigate the influence of imbibition on the matrix permeability, micro-fracture permeability, and fracture permeability. It is the first time to correlate permeability change with shale imbibition, and provide quantitative results of increase and decrease in permeability due to imbibition process in shale during hydraulic fracturing.

This paper uses the pressure build-up method to measure permeability of the shale sample, and applies the under-weighing approach to do the imbibition experiment. The Niobrara, Horn River, and Woodford shale formations are the source of the samples in the experiment.

The experimental results show that the imbibed fracturing fluid will damage and seriously reduce the matrix permeability of the shale sample. When the sample imbibes more fluid, the matrix permeability is reduced greater. Imbibition also decreases the fracture permeability of open fractures, but decrease is less than the reduction of matrix permeability. Moreover, there is a lubrication effect that can reopen micro-fractures on shale samples and stimulate and increase the micro-fracture permeability during imbibition.

Permeability is a criterion that determines the long-term production from a formation. By studying the permeability change caused by imbibition during hydraulic fracturing stimulation, this paper presents a new observation that imbibition in shale can not only damage, but also potentially stimulate the shale formation by increasing permeability due to open closed or sealed natural fractures.

1. Introduction

With the successful application of hydraulic fracturing technology in shale and other unconventional formations, crude oil production in the U.S. is expected to increase from 5 MMbbl/d in 2008 to 10.6 MMbbl/d in 2020; and oil production from shale and other low permeability reservoirs will grow to one half the national total crude oil production during the same period. From 2008, the U.S. shale gas production is expected to increase almost nine times (EIA, 2015).

The general procedure for hydraulic fracturing stimulation treatments has five main steps, including pad injection, gel slurry injection, flush injection, well shut-in, and water recovery. Water recovery is the last step of the hydraulic fracturing treatment before the well is put on production. This step is important and necessary during hydraulic fracturing because it can control and minimize damage from fracturing fluids. However, many operators reported that less than 50% of the injected fracturing fluid in shale formations could be recovered (Alkouh and Wattenbarger, 2013). This may be because the system energy is low after hydraulic fracturing in shale formations. Generally, the system energy is higher when fractures are more conventional and less complicated. The higher energy can cause a larger volume of flow recovery at a faster rate. But fractures in shale formations are complex so that the percentage of fracture fluid recovery is small and takes several weeks to

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complete flowback, much longer than in conventional formations (King, 2010; Wu et al., 2010). In shale, the impact on production of this large volume of remaining fluid becomes a concern. This is because many studies found that the remaining fracturing fluid could be imbibed by shale rock and fracture surfaces (Roychaudhuri et al., 2011; Makhanov et al., 2012; Yao et al., 2012; Zhou et al., 2014).

Imbibition is the process by which one fluid is displaced by another immiscible fluid in porous media. This displacement is the main reason for serious clay damage in clay rich shale formations. In addition to clay damage, the imbibed water also causes water blockage in tight gas reservoirs from massive hydraulic fracturing treatments (Qin, 2007).

Imbibition resulting from hydraulic fracturing can cause clay swelling in shale formations (Ghanbari et al., 2014). The swelling can occur in all clay minerals to various degrees; smectite and mixed-layer illite can expand up to 20 times their original volume (Hayatdavoudi, 1999). It is difficult to determine, however, whether clay swelling is harmful or helpful. Dutta et al. (2012) found that more fluid volume was imbibed in clay rich regions and the mobility of gas was expected to be reduced because of clay swelling. On the other hand, Morsy and Sheng (2014) had the opinion that clay swelling, due to imbibition, could create fractures along bedding in shale formations and thus expect to improve permeability and oil production.

Water blockages occur when water and other liquids are trapped in the porous media and impede gas production (Charoenwongsa, 2011). The hysteresis and discontinuous capillary pressure cause injected liquid fluids to be extremely difficult to produce. In addition, after production, the invaded zone liquid saturation could decrease to the residual saturation so as to prevent liquid displacement. Hence, the gas permeability and gas production are greatly reduced because of the additional gas flow resistance from the trapped liquid (Hadley and Handy, 1956; Land, 1968; Ehrlich, 1970). Previous studies found that water blockage decreased permeability only temporarily. The permeability was recovered, as long as the drawdown pressure was high enough (Holditch, 1979; Abrams and Vinegar, 1985; Mahadevan and Sharma, 2003; and Bazin et al., 2009). On the contrary, other investigations indicated that water blockage created permanent permeability damage because in very tight formations, it was difficult for drawdown pressure to be high enough (Penny et al., 1983; Soliman and Hunt, 1985). In addition, some numerical models showed that when the rock matrix imbibed fluid from fractures, the relative permeability of gas in the invaded zone decreased. During production, the imbibed fluid was produced first. Then the gas began to flow through the invaded zone to the fractures with the rise of relative permeability of gas in the water blockage zone (Barati et al., 2009; Charoenwongsa, 2011; Putthaworapoom et al., 2012, Zhang et al., 2014). Therefore, the water blockage was temporary.

In summary, previous studies show clay swelling is expected to either damage or stimulate formations; and water blockage is either permanent or temporary to damage formations. However, those previous investigations did not have the experimental data to answer the questions regarding damage or stimulation from the imbibition of fracturing fluid in shale formations. These questions are whether imbibition in shale formations results in damage or stimulation on long-term production. Also, if imbibition has a negative impact, is it permanent or temporary? In this paper, permeability is studied as the criterion of impact. Through experiments, this paper investigates permeability changes because of imbibition under various fracturing fluids in shale. It is the first time to quantify permeability changes as a function of shale imbibition. In addition, the results in this paper can explain how slick-water fracturing increases production in shale formations.

2. Experiment

The determination of permeability changes as a function of fluid imbibition is the main objective of the experiment in this paper. Therefore, the experiment consists of two parts: permeability measurement and the fluid imbibition experiment. The details of the permeability measurement and imbibition experiment will be discussed in the following parts.

For each sample experimental run, the original sample permeability was first determined through the permeability measurement. Then, the sample was immersed into a test fluid to begin the imbibition experiment. The sample permeability was measured again after one or two days. After that, the sample was put back into the test fluid to continue the imbibition experiment for another day. The permeability measurement was repeated, and the imbibition experiment was again followed. The duration of these repeated experiments was usually one week and sometimes up to one month. Finally, varying permeabilities were recorded as a function of time for the imbibition process.

2.1. Permeability measurement

The pressure build-up method was used for the shale sample permeability measurement. This is one of the most efficient methods to measure permeability of tight rocks.

2.1.1. Measurement principle

The principle of the pressure build-up method is that the constant inlet pressure of a confined shale sample is higher than the outlet pressure of the sample. The test records and analyzes the rate of outlet pressure increase as fluid is pumped through the sample. Nitrogen is used as the pressure build-up test fluid. Permeability of the shale sample is derived through the following equations.

Gas densities at the standard condition and at the test condition are calculated in Eq. (1) and Eq. (2).

$$\rho_{gs} = \frac{P_{gs}M}{RT_{gs}Z_{gs}} \tag{1}$$

$$\rho_{gt} = \frac{P_{gt}M}{RT_{gt}Z_{gt}} \tag{2}$$

ρ_{gs}, ρ_{gt} are gas densities at the standard condition and at the test condition, respectively; P_{gs}, P_{gt} are pressures at the standard condition and at the test condition, respectively; T_{gs}, T_{gt} are temperature at the standard condition and at the test condition, respectively; Z_{gs}, Z_{gt} are compressibility factors at the standard condition and at the test condition, respectively; M is gas molar mass; and R is gas constant.

Hence, gas density at the test condition is represented in Eq. (3).

$$\rho_{gt} = \frac{T_{gs}\rho_{gs}Z_{gs}}{P_{gs}}\frac{P_{gt}}{T_{gt}Z_{gt}} \tag{3}$$

where: $Z_{gs} = 1$

A one dimensional gas continuum equation is Eq. (4).

$$\frac{\partial(\rho_{gt}v_x)}{\partial x} = -\frac{\partial(\varphi\rho_{gt})}{\partial t} \tag{4}$$

v_x is velocity in x direction; φ is porosity; and t is time.

When the gas density equation is substituted into the gas continuum equation, Eq. (5) is derived.