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Water imbibition of shale and its potential influence on shale gas recovery—a comparative study of marine and continental shale formations

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A B S T R A C T

A large volume of fracturing fluid is pumped into a well to stimulate shale formation. The water is imbibed into the reservoir during this procedure. The effect of the imbibed water on gas recovery is still in debate. In this work, we study the spontaneous imbibition of water into marine shale samples from the Sichuan Basin and continental shale samples from Erdos Basin to explore the fluid imbibition characteristics and permeability change during water imbibition.

Comparison of imbibition experiments shows that shale has stronger water imbibition and diffusion capacity than relatively higher permeability sandstone. Once the imbibition stops, water in shale has stronger ability to diffuse into deeper matrix, the water content in the main flow path decreases.

Experiments in this study show that marine shale has stronger water imbibition capacity than continental shale. The permeability of continental shale decreases significantly with increasing imbibition water volume; however, the permeability of marine shale decreases at first and increases after a certain imbibition time. The induced fracture is obvious in the marine shale. SEM analysis shows that the relationship between the clay mineral and organic matter of continental shale is much more complex than that of marine shale, which may be the key factor restricting the water imbibition because the flow path is trapped by swelled clay minerals.

Through this study, we concluded that whether gas recovery benefits from water imbibition depends on three aspects: 1) the diffusion ability of liquid into matrix; 2) the new cracks introduced by imbibed water; and 3) the formation sensibility. This study is useful for optimizing fracture fluids and determining the best flow-back method.

1. Introduction

A relatively large volume of fracturing fluid is pumped into a formation to stimulate an unconventional gas formation (Palish et al., 2010; Soliman et al., 2012). The performance of shale hydraulic fracturing shows that a large amount of fracturing fluid (generally more than 50%) is retained in shale formation after flow-back (Engelder et al., 2014). Fast flow-back technique after hydraulic fracturing is used in conventional gas reservoirs to improve flow-back rate and production rate. This technique is meaningful for unconventional gas reservoirs to a certain degree; however, different situations exist in shale gas flow-back and production. Ghanbari et al. (2013) investigated the relationship between flow-back rate and production rate and found that there were quite a portion of wells with low flow-back rate had high production rate. A soak-back technique is then proposed to enhance production after hydraulic fracturing which refers to a period of well shut-in (soaking time) to soak the fracture fluids to improve productivity (Ali Habibi et al., 2015; Dutta et al., 2014).

During this process, water will be imbibed into matrix in the

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fractured reservoir by capillary pressure (Cai et al., 2014) and chemical osmotic pressure (Fakcharoenphol et al., 2014). Fracture fluids imbibition is one key factor that causes fluid loss and low flow-back rate. The effect of water imbibition is still in debate for the shale gas production now (Ali Habibi et al., 2015). Water imbibition has always been recognized as a source that leads to productivity damage in the conventional theory. Spontaneous imbibition will cause formation damage based on the conventional theory of water blockage, especially in unconventional reservoirs with containing extremely small pores with strong capillary pressure (less than 100 nm) (Bennion and Thomas, 2005; Roychaudhuri et al., 2013; Odumabo et al., 2014). However, recent studies show that spontaneous imbibition of fracturing fluid can be a driving force to enhance gas recovery in shale gas reservoirs (Dehghanpour et al., 2012; Roychaudhuri et al., 2014). Practices show that additional wells shut-in after fracturing can improve productivity effectively, and a 4.4 fold improvement can be seen in some wells (Yaich et al., 2015). Adding surfactants into fracturing fluids can improve this effect which is approved in Bakken (Wang et al., 2012).

The soak-back technique is to use the spontaneous imbibition of fracturing fluid as a drive force to improve the gas recovery, however; additional wells shut-in pose several bad effects to some wells. Crafton and Noe (2013) and Ghanbari et al. (2013) pointed out that some wells receive productivity loss by well shut-in after fracturing, and the effects are significantly influenced by surfactant additives. Evaluation of “soakback” effect in Marcellus shows that one in four blocks receives a negative effect (Yaich et al., 2015). Thus, studies should urgently determine the potential influence of water imbibition on shale gas recovery (Yan et al., 2015).

Spontaneous imbibition is a natural phenomenon in porous media. Cai and Yu (2012) summarized the research development of the imbibition theory and analyzed the model details including Lucas-Washburn model Terzaghi model, Handy model, Mattax and Kyte model and Aronofsky model. The fractal theory and numerical simulations are also powerful to study the imbibition in complex porous media (Cai et al., 2010, Cai and Yu, 2011). These methods can be used to analyze the fracturing fluids imbibition in shale gas reservoir. However, the imbibition characteristic of different rocks differs and the high clay content made the chemiosmosis play an important role in the process.

There are large potential shale gas resources in the continental environment in China (Zou et al., 2010). According to Wang et al. (2013), continental shale formation is believed to be a promising target in China because of its large area, stable thickness, high total organic content (TOC) and high gas content. Horizontal well drilling and multi-stage hydraulic fracturing technology are used to develop continental shale gas; however, the productivity is much lower than that of marine shale gas in Fuling and Weiyuan of China. The water imbibition may be a key factor affecting this situation.

In this study, we conducted comparative imbibition experiments and permeability experiments on core plugs from the Longmaxi marine shale formation, the Chang-7 continental shale formation and the Xujiahe sandstone formation to investigate the fluid imbibition characteristics and the potential influence on gas recovery.

2. Samples and methodology

2.1. Samples

The samples are from Longmaxi Marine Shale Formation of Lower Silurian in Sichuan Basin and Chang-7 Continental Shale Formation of Triassic in Erdos Basin.

The Longmaxi shale sample is a fresh core sample from a well drilled at depth of 3328.54–3358.54 m and is cut into four twin plugs for consistent and comparative imbibition experiments (LMX-1, LMX-2, LMX-3, LMX-4). The thickness of these formations ranges from 60 m to 420 m. The TOC of the Longmaxi formation is 2.5%–8.3% with an average of 5.2%. The gas content is 1.7–3.3 m^3/ton. The Chang-7 shale sample is a fresh core sample from a well drilled at depth of 1455.33–1458.51 m and cut into four twin plugs (CH7-1, CH7-2, CH7-3, CH7-4). The TOC of Chang-7 is 3.5%–6.5% with an average of 4.7%. This formation has medium gas content of 2.0–5.0 m^3/ton. For comparison purposes, two sandstone samples (XJH-1, XJH-2) are chosen from Xujiahe Formation in Sichuan Basin.

The samples were dried at 105 °C for 12 h before the experiment until the mass remained unchanged. Sample porosity was measured by helium porosimeter (KXD-III type). The porosity distribution of three types of samples presents certain differences. XJH sandstone samples have the highest porosity with an average value of 13.22%. LMX samples have higher porosity (average 3.50%) than CH7 samples (average 2.37%). Sample pulse-decay permeability was determined by an ultra-low permeability measurement instrument, confining pressure exerted by water and pore pressure exerted by helium. The following test conditions were used: temperature of 25 °C; confining pressure of 8 MPa; and pore pressure of 5 MPa. The permeability of XJH sandstone samples ranged from 2.11 mD to 2.34 mD. The range of LMX shale samples permeability varied from 0.0016 mD to 0.0028 mD. The permeability of CH7 shale samples changed from 0.0014mD to 0.0062mD.

Table 1 provide the rock mineralogy of three kinds of sample based on X-Ray Diffraction (XRD) analysis. The main minerals of LMX shale are quartz (46 wt%), feldspars (11 wt%), calcite (8 wt%), and clay minerals (28 wt%). Clay minerals of LMX shale mainly consist of illite and mixed layer of illite/smectite, where illite has a portion of 75%. The main minerals of CH7 shale are quartz (24 wt%), feldspars (23 wt%), and clay minerals (49 wt%). Clay minerals of CH7 shale are mainly consist of illite and mixed layer of illite/smectite; however, its illite/smectite content reaches 48%. The main minerals of XJH sandstone are quartz (40 wt%), feldspars (27 wt%), dolomite(13 wt%) and clay minerals (49 wt%). Clay minerals of XJH sandstone mainly consist of illite, chlorite and a mixed layer of illite/smectite.

2.2. Methodology

First, we measured spontaneous imbibition of distilled water into plugs and compared the main characteristic parameters for the three kinds of sample, including liquid imbibition capacity and liquid diffusion ability. In the imbibition process the conductivity is measured in real time. Then, we conducted two tests to investigate the impact of imbibition to permeability. The first test was set to test the permeability values before and after water imbibition in dry condition where the whole core contacted with liquid. The second test was set to test the permeability during the water imbibition where one side of the core contacted with liquid. The two tests are made to observe the influence of water imbibition to gas permeability more clearly. The inconsistence is negligible here. Finally we conducted Scanning Electron Microscope (SEM) analysis on the samples after imbibition.

2.2.1. Spontaneous imbibition of distilled water into samples

In the spontaneous imbibition experiment, distilled water was used as working liquid. The sample contacts the liquid with all surfaces. The schematic is presented in Fig. 1. The imbibed water weight was measured on line by a balance (METTLER LE204E) connected to a computer. The method to obtain the imbibed water weight is shown in Fig. 1. This method can eliminate the influence of water vaporization from the container to the imbibed water weight measurement. The experiments were performed at room