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Original article

Impact of fracturing liquid absorption on the production and water-block unlocking for shale gas reservoir

Yinghao Shen[1]*, Hongkui Ge[1,2,3], Xiuling Zhang[4], Long Chang[1], Dunqing Liu[1], Junrong Liu[1]

[1]*Unconventional Natural Gas Institute, China University of Petroleum, Beijing 102249, P. R. China*

[2]*State Key Laboratory of Petroleum Resources and Prospecting, Beijing 102249, P. R. China*

[3]*China University of Petroleum, Beijing at Karamay, Xinjiang 834000, P. R. China*

[4]*CNPC Engineering Technology R&D Company Limited, Beijing 102206, P. R. China*

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Corresponding author:
*E-mail: shenyinghao@126.com

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Abstract:
A large amount of liquid is pumped into the shale gas reservoir during hydraulic fracturing, and the fluid flowback ratio is usually low. However, field experience showed that the liquids did not cause severe damage to shale gas reservoir. It is urgent to clarify the water block unlocking mechanism of a shale gas reservoir. This work is to discuss the water block unlocking mechanism in shale gas reservoir. Based on the characteristic study of shale gas formation, the fracturing fluid absorption mechanism, absorption ability and impact on shale gas formation damage are systematically studied. Study shows that ultra-low water saturation, abundant micro- to nano- tubulars and a huge contact area are the control factors for strong fluid absorption ability of gas-shale. The strong water absorption capacity of the shale gas formation matrix is a key factor in removing water block. Organic matter also has an important influence on absorption ability and gas production. A conceptual evaluation criterion for water block unlocking is proposed based on core absorption capacity, original water saturation and fracture density. The shut-in after hydraulic fracturing is beneficial to gas production and can reduce water production for certain shale gas reservoir.

1. Introduction

The development of unconventional oil/gas resources in China has made important progress. The shale gas of SINOPEC Fuling is believed to be a typical high-quality marine shale gas. It locates in Sichuan Basin and gas storage in upper Ordovician and Lower Silurian. The proven geological reserves of the marine shale gas exceed 6,000 $\times 10^8$ m^3 and is Chinas first large-scale shale gas field. This has stimulated the development of unconventional oil/gas resources in China (Haikuan et al., 2012; Wang et al., 2015; Dong et al., 2016). One key technology for the successful development of shale gas is large-scale hydraulic fracturing. In this process, a large amount of liquid is pumped into formation. The fracturing practice shows that the fluid flowback ratio for shale gas reservoir was low, usually 20%-40% in the United States (Penny et al., 2006; Zhong, 2011; King, 2012) and even as low as 5% in Fuling, China.

Water block is proven to be one of the main mechanisms for low permeability (He et al., 1994; Civan, 1996; Dehghanpour et al., 2012). With an increase in water saturation, production will significantly decrease. A water block prediction model was proposed in 1996, which is used to predict the level of water block based on the reservoir permeability and initial reservoir water saturation (Bennion et al., 1999). The water level of water block is more serious with a lower permeability and initial water saturation based on this model, and it is used for several low permeability reservoirs (He et al., 2003; Erwin et al., 2005). However, the relationship between production and the flowback ratio was significantly different from that of the conventional reservoir; the production of shale gas with a low flowback ratio is not affected, and its productivity is even higher. This is opposite to the mutual understanding that an ultra-low-permeability reservoir easily forms water block damage. The reason might be the interaction between fracturing fluids and the reservoir. Scholars have realized that the abundant micro-nano pores in the shale gas reservoir

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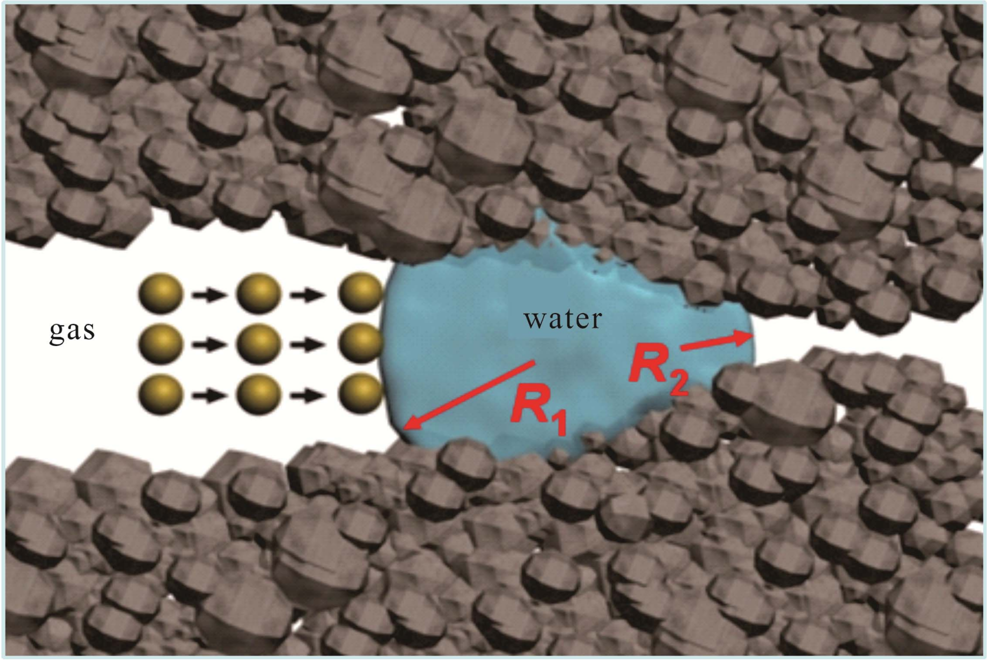


Fig. 1. Water block damage caused by capillary force (Geng et al., 2011).

will produce stronger capillary force to induce spontaneous imbibition. However, most researchers still believe that it will cause serious water block, which is considered an important damage mechanism after the water enters the micro-nano pores.

Spontaneous imbibition studies were proposed to investigate the interaction between water and shale (Cai et al., 2010, 2011; Shen et al., 2016). It is recognized as one important mechanism for fracturing fluid absorption in shale (Cai et al., 2017a; Shen et al., 2017). The imbibition characteristic of shale is different from that of regular tight sand, for example the imbibition ability of shale is stronger than regular tight sand (Shen et al., 2016). The permeability change of shale after water imbibition is also proven to be different from that of regular tight sand (Shen et al., 2017). Hence, the understanding of fracturing fluid absorption of shale is crucial to analysis of the water block mechanism. This phenomenon may depend on the different reservoir properties of shale and regular tight sand gas. For example, a shale gas reservoir has special mineral components and microstructure.

Well shut-in after hydraulic fracturing was performed to reduce the flow-back rate in some shale gas fields. The purpose is to improve the gas production rate and reduce the water treatment, which is related to development costs. However, finding a rational well suitable for applying this scheme is difficult, and there are no evaluation criteria until now. Therefore, it is urgent to understand the water-block unlocking mechanism and propose a reasonable evaluation criterion.

This study is designed to understand the water-block unlocking mechanism of an unconventional gas reservoir based on the fracturing fluid absorption mechanism and its impact on gas production. A new evaluation method is proposed to consider the factors controlling the water block unlocking mechanism.

2. The key factor of formation damage for tight reservoirs

Formation damage is the reduction in reservoir permeability resulting from various engineering measures during the process of oil/gas exploitation, including drilling, hydraulic fracturing, production, and other processes, which are usually caused by physical, chemical, biological, hydrologic and thermal interactions between a porous medium reservoir, mineral particles and fluid and the physical compaction of the formations. Common types of formation damage include solid invasion, water sensitivity, acid sensitivity, velocity sensitivity, clay swelling and stress damage (Civan, 2011). Water block is the main factor in formation damage for low permeability gas reservoirs. The water block effect is a phenomenon in which the formation pressure is unable to force extraneous fluids out of the formation due to the retention action of capillary force, thus reducing the oil/gas permeability (Jiang et al., 2013) (Fig. 1). Due to the small pore throat of a low permeability gas reservoir, there is usually a strong water block effect. The water block effect is reflected in the water/gas permeability ratio (Fig. 2). The gas phase permeability decreases rapidly with an increase in water saturation; after the water saturation has exceeded a certain value (the maximum water saturation for gas phase flow), there will be a blind zone of permeability, and neither water nor gas can flow. After the water saturation has exceeded the minimum flow saturation of the water phase, the water phase will enter continuous phase to begin to flow (Shanley et al., 2004). Overall, water block of a low permeaibility gas reservoir significantly affects the gas well production.

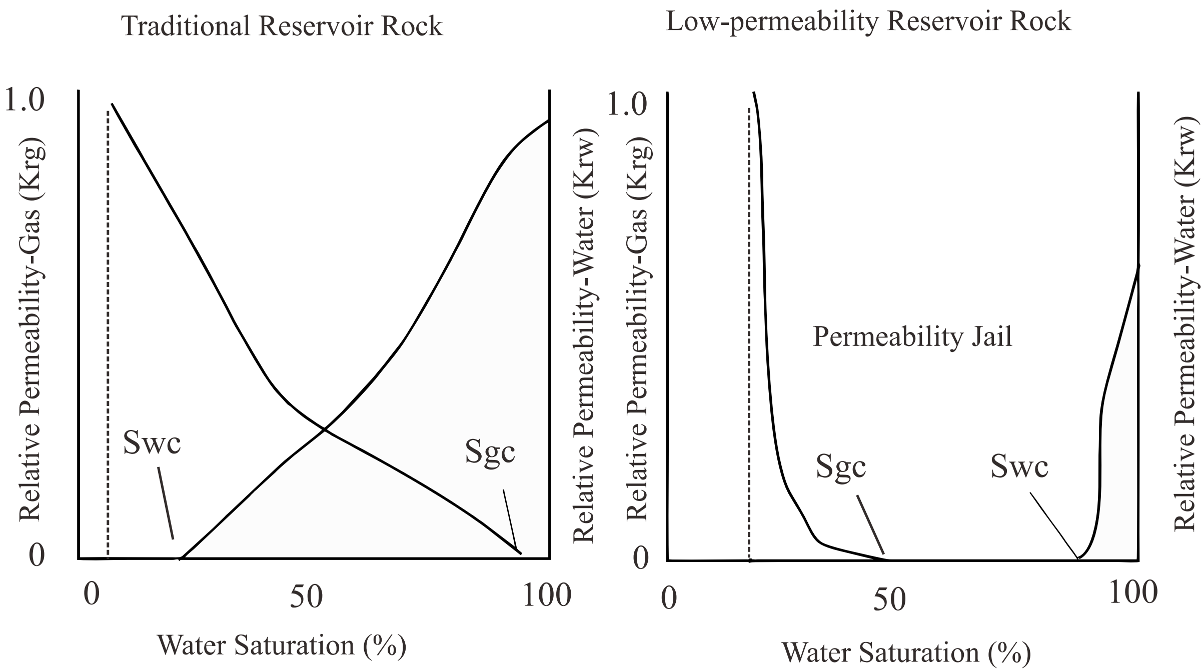


Fig. 2. Curves of relative permeability for traditional reservoir and tight reservoir (Shanley et al., 2004).

After a large amount of fracturing liquid is absorbed into the formation, the impact on gas production and whether a serious water block will be produced have become the focus in the development of low-permeability gas reservoirs. A mathematical model for predicting the water block damage was proposed in 1996 (Bennion et al., 1996).

$$APT_i = 0.25lgK_a + 2.25S_{wi} \tag{1}$$

where APT_i – water block index, dimensionless; K_a – reservoir gas permeability, μm^2; S_{wi} – reservoir initial water saturation.

This formula has been used as an important criterion for judging the water block (Bennion, 2005; Gupta, 2009). The criterion is shown in Table 1. The table shows the evaluation criterion of water block severity established by Eq. (1). It can be seen from the table that the water block is more serious when the initial water saturation is lower. This does not represent the actual development condition of shale gas. Liu et al. (2013) proved that initial water saturation was low under rich gas conditions and initial water saturation was high under lean gas conditions for a shale reservoir. Low water saturation has become an important criterion for selecting shale gas areas; the production capacity after hydraulic fracturing is usually higher. Usually there is low water block with lower initial water saturation for shale gas reservoir. The analysis shows that this traditional water-block evaluation criterion is not suitable for shale gas.

Considering the JY1HF shale gas horizontal well in Fuling Field as an example, the combined operation technology of the pump-down drillable bridge plug and perforation were used. Fifteen sections were fractured overall; the total volume of injected fluid was 19,972.3 m^3 and the propping agent was

Table 1. Evaluation criterion for water block severity.

Value Range	Damage Degree
APT_i >1.0	No significant water block effect
0.8 < APT_i <1.0	Potential water block effect in the formation
APT_i <0.8	Significant water block effect

968.82 m^3. The flow-back rate is lower than 10%, but an open-flow capacity of 16.7104 m^3/d was obtained by the well test (Zhou et al., 2014). High formation damage did not occur in some shale gas wells, even when thousands of cubic meters of liquids are pumped into the formation, and the fluid flow-back ratio is low for shale. Field data in Fuling showed that the production rate was usually higher when the flow-back ratio was lower, and no serious water block occurred.

3. Water absorption of a shale gas reservoir

There are two main forces for water absorption after hydraulic fracturing. The first one is the adsorption force by clay minerals (Busch et al., 2016; Cai et al., 2017b) which including osmotic hydrationand surface hydration. The double electrical layers theory is usually used to explain osmotic hydration. The water is adsorbed into the Clay intercrystallite. The water adsorption capacity is controlled by the clay mineral content, reservoir water salinity and fracturing fluids salinity (Fig. 3). The surface hydration refers to water adsorpted by electrovalent bond. There are high clay mineral content for most organic shale. So, absorption by clay minerals is an impo-

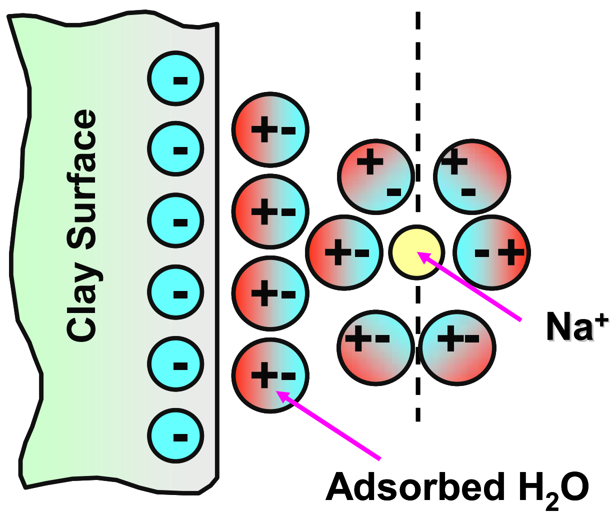


Fig. 3. Sketch map of the double layer on the surface of clay minerals (Passey et al., 2010).

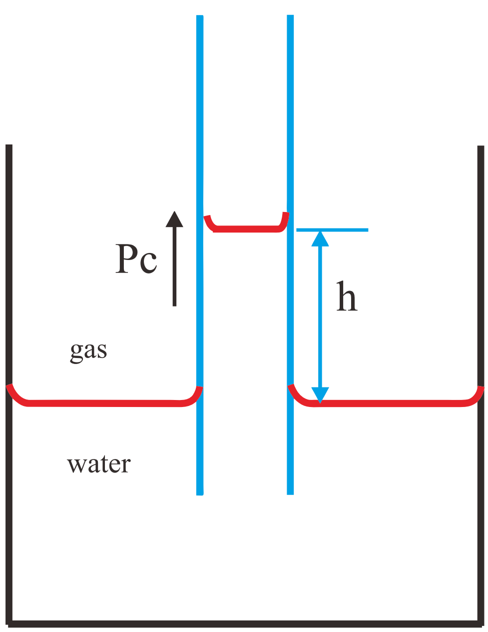


Fig. 4. Spontaneous imbibition of liquid under the action of capillary force.

rtant force for water absorption.

The micro-nano capillary imbibition is the other important mechanism of fracturing liquid absorption by the matrix and affects the damage of the shale gas reservoir (Lin et al., 2017; Meng et al., 2017). Spontaneous imbibition by Capillary pressure is the process for the wetting phase to spontaneously displace the non-wetting phase (Ding et al., 2007). The capillary force is the driving force (Fig. 4). The smaller the pore radius is, the stronger the capillary force is, which provides a high force to imbibe fracturing fluids.

There will be a complex fracture network after large-scale hydraulic fracturing. The water injected will contact the large

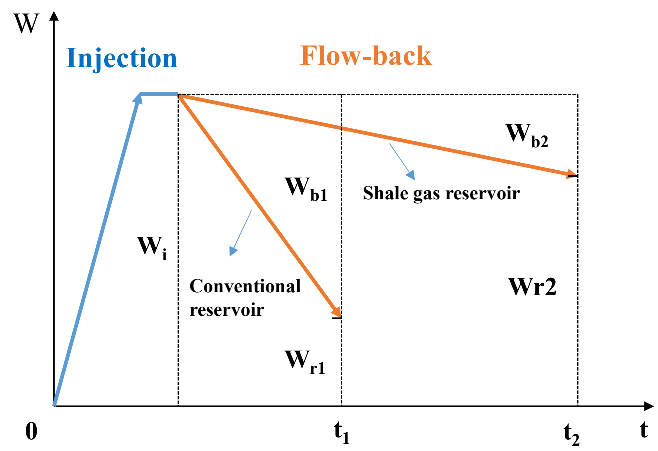


Fig. 7. Schematic diagram of flow-back rate of a conventional reservoir and a shale gas reservoir.

fracture surface created in this process. Based on the two main forces for water absorption discussed above, the water absorption after hydraulic fracturing is controlled by two parts. One part is the retained fluids in fractures, which are maintained as bound water in the fracture face and moveable water in the fracture spaces. The other part is the imbibed fluids in the matrix, which are maintained in the matrix pores. Figs. 5 and 6 show the water trapped by the complex fracture, including the water trapped by fracture, bounded water by capillary pressure, bounded water by surface force and imbibed water by micro-pores of the shale matrix.

The fracturing fluids enter the reservoir in this process, and the flow-back rate is related to the properties of the gas reservoir. Fig. 7 shows the comparison schematic of the flow-back rate between a conventional reservoir and a shale gas reservoir. In Fig. 7, abscissa axis is the working time during hydraulic fracturing and W is the total fluids injected in the formation. The blue line represents the fracturing fluids injection process. The orange line represents the flow-back process. For conventional reservoir, the flow-back time (t_1) is usually shorter and volume (W_{b1}) is usually higher than shale gas reservoir (t_2 and W_{b2} respectively). W_{r1} and W_{r2} represents the water held up in the formation for conventional and shale gas reservoir. The flow-back rate is lower than 1 because water will be retained in the fractures. Generally, the flow-back rate is controlled by fracture complexity, fracture aperture, fracture surface roughness and water imbibition into the reservoir matrix. The flow-back rate is controlled by fracturing fluid adsorption. According to Fig. 7, the retained fracturing fluids are far lower and the total interaction time is longer than those in a conventional reservoir.

The above analyses showed that the strong action of water absorption of the shale gas reservoir was the key to flowback of the fracturing liquid. There was a large difference for the spontaneous imbibition between shale and the conventional reservoir. The main reason for this finding was the special nature of the shale reservoir, and its impact on spontaneous imbibition include the following factors.

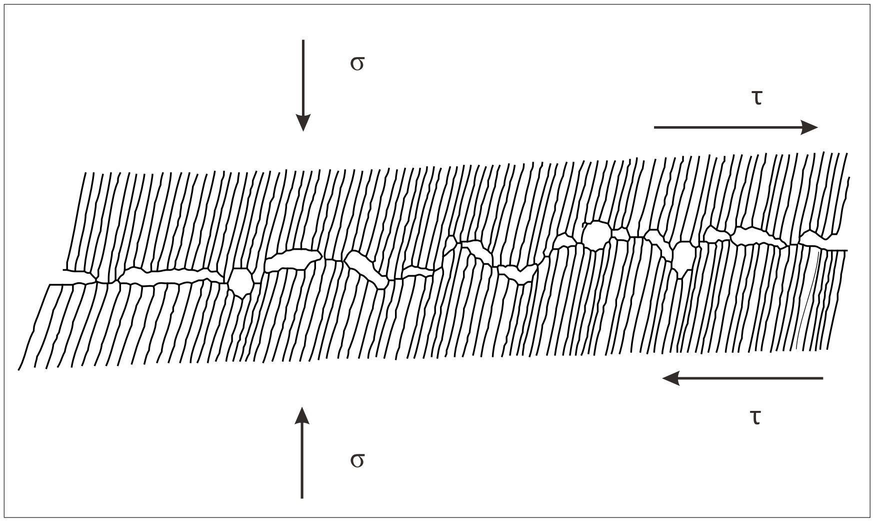


Fig. 5. The water trapped by fracture heterogeneity.

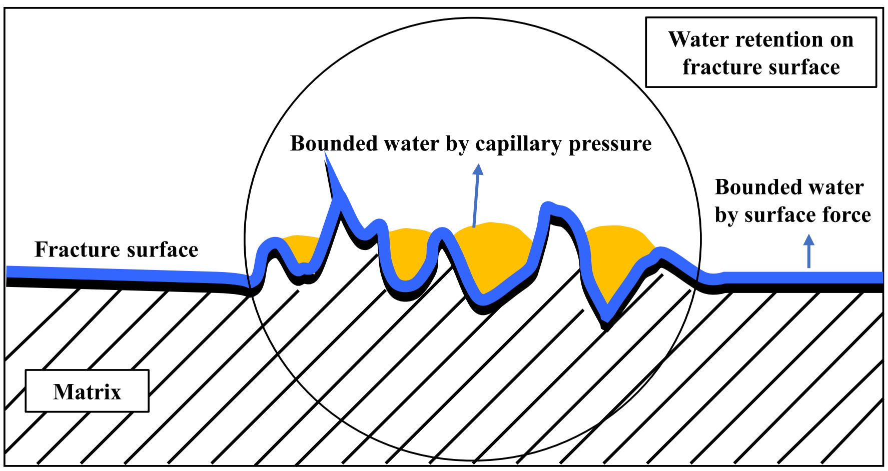


Fig. 6. Water retention on the fracture surface.

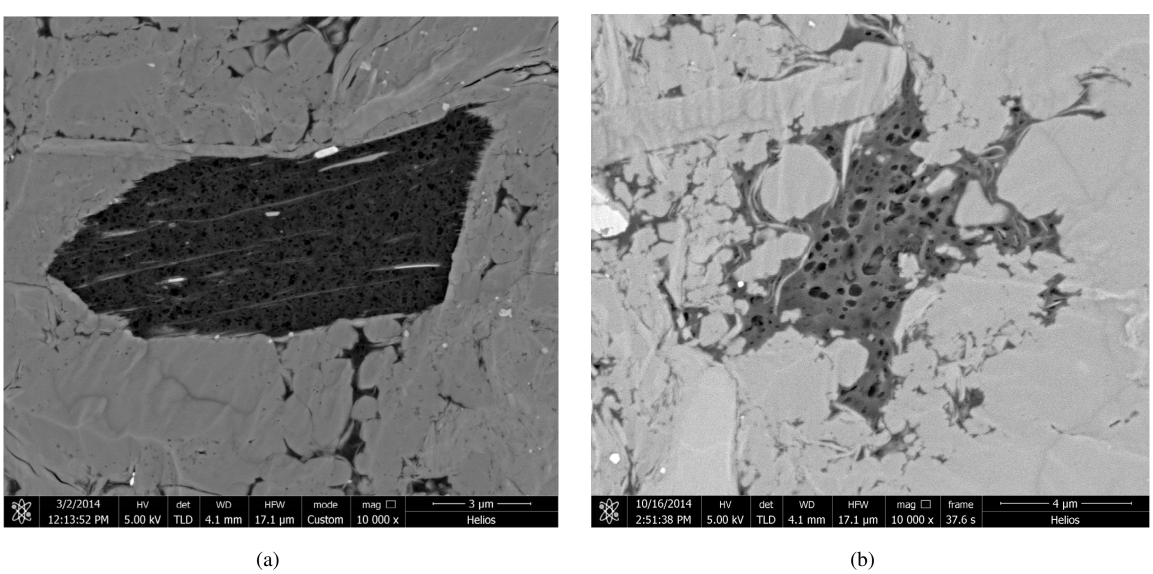


Fig. 8. Shale microscopic imaging in Longmaxi formation in Chongqing.

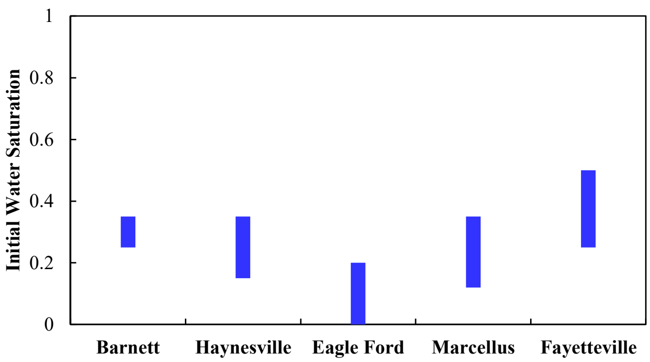


Fig. 9. Statistics of water saturation in shale gas reservoirs in North America.

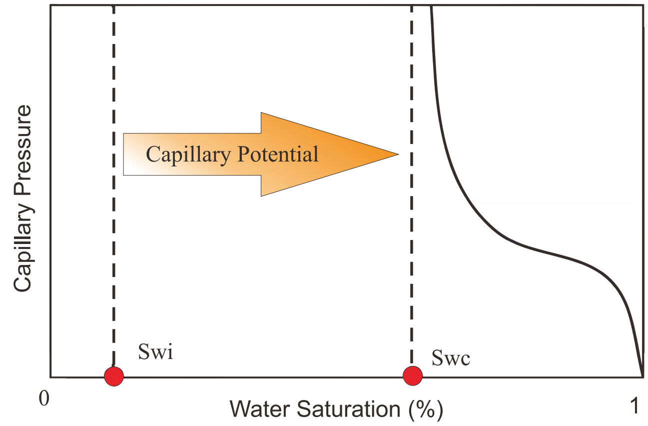


Fig. 10. Capillary force potential resulting from ultra-low water saturation.

3.1 Shale has abundant micro-nano pores

Shale has rich micro-nano pores and fractures. The nano-level pores were first observed in China in 2010; the nano-level pores in the shale gas reservoir were dominated by organic matter inner pores, particle inner pores and the authigenic mineral intercrystal pores, with a pore diameter range of 5-300 nm and a subject range of 80-200 nm (Zou et al., 2011). The existence of organic matter is one significant characteristic of shale compared to a tight gas reservoir (Pang et al., 2016a, 2016b). Fig. 8 shows the typical scanning electron microscope images of shale samples in the Longmaxi Formation in Chongqing, China. The Longmaxi shale are of high thermal maturity and the micro/nano pores are developed in the mature kerogen. The thermal maturity of the shale sample used for Fig. 8 is 2.68% and 2.80%, respectively. Because micro-nano capillaries were developed and the pore throats were small, they had ultra-high capillary force to ensure stronger fracturing fluid absorption ability.

3.2 The high-quality shale gas reservoir usually has ultra-low water saturation

Fig. 9 shows the initial water saturation statistics of different shale gas reservoirs in the North America regions. The water saturation of the shale gas reservoir is usually lower, and its bound water is usually 60-80%. These reservoirs are in an unsaturated state. Several key factors result in ultra-low water saturation, including hydrocarbon-generating drainage, water involvement in a hydrocarbon-generating chemical reaction, vaporization and liquid-carrying effect (Fang et al., 2014). These factors enable the shale gas reservoir rich in organic matter to easily achieve ultra-low water saturation under conditions of good overlaying stratum and higher pressure, which is another special characteristic of a shale gas reservoir.

Based on the gas-water capillary theory, ultra-low water saturation makes the shale extra-dry and creates the potential trend of capillary force, as shown in Fig. 10. After the fracturing liquids flow into the reservoir, they first meet the absorption of the rock inner surface liquid to reduce the capillary force potential. This enables a good-quality shale gas reservoir to have strong water sorption capacity. Here, Swi represents the initial water saturation and Swc represents the irreducible water saturation.

3.3 The huge contact area is formed after large scale hydraulic fracturing

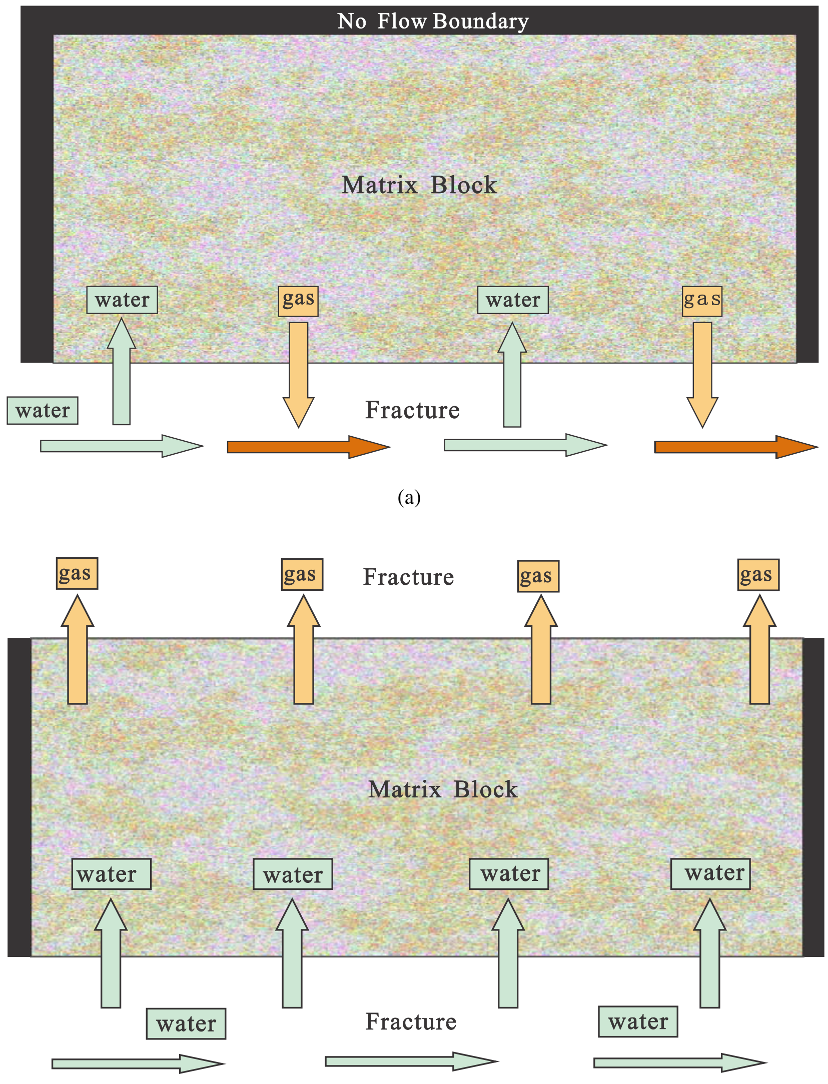
The goal of large-scale hydraulic fracturing is to get a complex fracture network. The SRV (stimulated reservoir volume) is crucial for gas production in tight shale gas reservoirs. The fracture network will always be more complex for a well with a better fracturing effect. Based on the fracture networks of different complexity formed by staged fracturing horizontal wells, the complex fracture network formed by large-scale fracturing increases the contact area of the liquid with the reservoir. The fracture surface area is significantly larger than conventional vertical well fracturing and can be on the order of $5\sim10\times10^5$ m^2 in a typical fracturing job for a shale gas well. The water imbibed by the shale formation could be $4{,}500\sim9{,}000$ m^3 based on water imbibition experiments. There will be stronger fracturing fluid absorption of the liquid with a more complex fracturing network.

Due to the above features of a hydraulic fractured shale gas reservoir, large amounts of fracturing fluids injected into the formation will be absorbed by the shale formation; the influence on gas production is different compared to conventional formations.

4. Impact of fracturing liquid absorption on the production and water-block unlocking

4.1 The strong fracturing fluids absorption ability of the formation enables the shale gas reservoir to remove the water-block

A shale gas reservoir has strong spontaneous imbibition ability, because a high-quality shale gas reservoir usually has ultra-low water saturation, its micro-nano capillary is developed, and after the fracturing, complicated fracture network



(a)

(b)

Fig. 11. Sketch of counter-current (a) and co-current (b) spontaneous imbibition (Qasem et al., 2008).

and huge contact areas will usually be formed, which enables the formation to have strong water absorption ability(Shen et al., 2016). The fracturing liquid will enter the main pore channels, which are the connected pore, throat and fractures. A serious water block will occur if the fracturing liquid is held up. Because the shale matrix has strong absorption ability, the fluids in the main pore channels can be absorbed by the reservoir matrix to reduce the water content and reduce liquid retention in the main pore channels, and the blocked gas by water invasion can flow into the well again.

4.2 The Volume fracture network changes the water imbibition and gas flow direction

The main gas flow direction is against the direction of fracturing fluids into the formation after conventional two-wing hydraulic fracturing, which is the reason why water-block occurs in tight gas reservoirs. This phenomenon is similar to a counter-current imbibition, where the flow direction of the wetting phase and non-wetting phase is opposite to each other (Fig. 11(a)). The success of large scale fracturing in a shale gas reservoir means that the shale is fully fractured. The volume fracture network will change the water imbibition and gas flow direction, where the gas flow direction is the same as the direction of fracturing fluids into the formation. This phenomenon is similar to a spontaneous co-current spontaneous, where the flow directions of the wetting phase and non-wetting phase are the same in the process of spontaneous imbibition (Fig. 11(b)).

Overall the volume fracture network controls the water-block unlocking mechanism, which is based on the patterns of water imbibition and gas flow. When the facture density is small, the wetting phase and non-wetting phase share the flow channel, the resistance of counter-current spontaneous imbibition is usually larger, and the non-wetting phase cannot easily flow out. However, when the facture density is large, the co-current spontaneous imbibition has a “displacemen” funct-

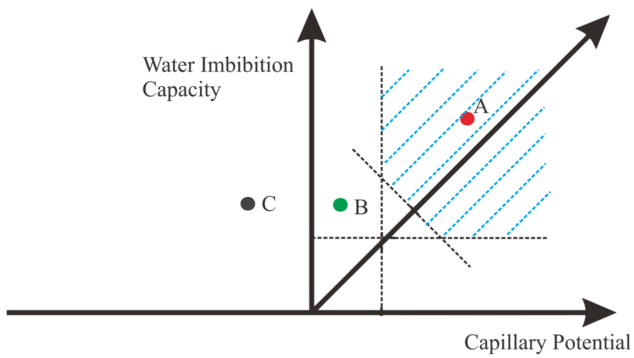


Fig. 12. Evaluation criterion of water block in a shale gas reservoir.

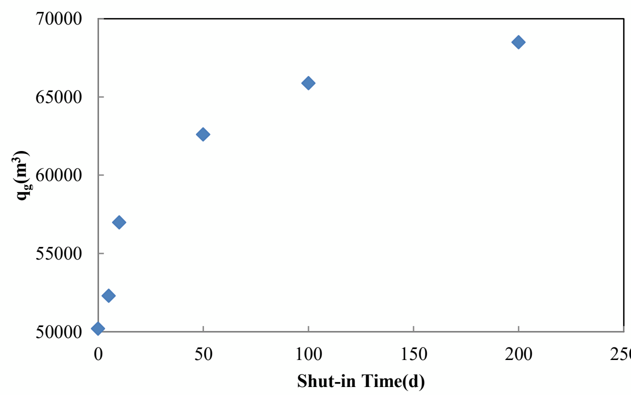


Fig. 13. Relationship between shut-in time and gas production after fracturing.

ion to a certain extent.

4.3 Organic matter has an important impact on water-block unlocking and production capacity

The rich content of organic matter is a typical feature of shale gas reservoirs. The density of organic matter is usually smaller, which is approximately half of the inorganic matter. So Its volume is large than the weight, the porosity of organic matter is highly developed, the internal connectivity is better, and the gas content and permeability in the pore network of organic matter are high; therefore, it provides good flow channels, though the organic material is typically much less than half of the inorganic matter in the majority of organic shales (Liu et al., 2016; Zhang et al., 2017). The surface of organic matter is usually characterized by strong oil wetness, so the shale is usually characterized by mixed wetting, namely, the oil wetting system of organic matters and the water wetting system of inorganic minerals. The double-wetting system enables fluids to more easily enter the pores of inorganic matter via spontaneous imbibition rather than the network of organic matters; the gas in the pores of inorganic matter can be displaced into the pores of organic matter. So the organic matter has a shielding effect on the damage of water-based fluids.

4.4 Evaluation Criterion of Water-Block unlocking in a Shale Gas Reservoir

Based on the above analyses, we concluded that water imbibition capacity, capillary potential, fracture density and organic matter content are the main factors affecting water-block unlocking. A conceptual evaluation criterion is proposed to understand the water-block unlocking mechanism in a shale gas reservoir as shown in Fig. 12. The criterion of water-block unlocking considers the water imbibition capacity (x-coordinate), capillary potential (y-coordinate) and fracture density (the 3^{rd} coordinate). In the criterion, capillary potential refers to the difference between irreducible water saturation and initial water saturation, which represents irreducible water saturation-initial water saturation.

Table 2. Basic Parameters for Reservoir Simulation.

Parameter	Value
Reservoir Depth	2,500 m
Reservoir Pressure	3,500 MPa
Porosity	6%
Initial Water Saturation	0.15
Matrix permeability	0.005 mD
Horizontal Length	1000 m
Formation Thickness	30 m
Matrix Fracture Flow Conductivity	0.01 mD*m
Propped Artificial Fracture Flow Conductivity	10 mD*m
Unpropped Artificial Fracture Flow Conductivity	1 mD*m

For a high-quality shale gas reservoir with low water saturation and strong water imbibition capacity determined through lab experiments, there will be an "A" zone in Fig. 12 if the formation can be fractured into high density fractures. In this zone, most of the fracturing fluids can be absorbed into the formation; the main gas production direction is in the water imbibition direction. The fracturing water injected does not cause serious water-block, which is the water-block unlocking we discussed before. The best scheme after fracturing is shutting the well and letting the formation absorb the fracturing fluids. If a large amount of fracturing liquid has been injected, the utilization of a large amount of rich micro-nano pore fractures to absorb the fracturing liquid can effectively reduce the fluid volume in the fractures and large pore channels to remove a water block over a shut-in time. The formation energy will be enhanced after the fracturing liquid enters the reservoir. The shut-in scheme is conducive to improving the production capacity in situation "A" in Fig. 12. In this case, the flow-back strategy can be developed: after the initial flow-back, the gas production rate will rise, and water yield will decrease after the well is shut for 2-3 months.

A reservoir model is built based on the data of a typical shale gas reservoir. The basic parameters adopted are in Table

2. A ten staged fracturing horizontal well is designed in the reservoir. We modeled the shut-in after hydraulic fracturing to study the influence of fracturing fluids abortion to gas production. Fig. 13 shows the modeling result. The gas production increased by 24.7% after well shut-in for 50 days and increased by 36.5% after the well was shut for 300 days; the cumulative water production decreased by 48.4% after the well was shut in for 50 days and decreased by 68.4% after well shut in for 300 days.

In the "C" zone of Fig. 12, the initial water saturation is higher than the irreducible water saturation. The water pumped into the formation could not be absorbed and is more prone to introduce water block. For this kind of reservoir, it is necessary to strengthen the initial flow-back to reduce the time of fracturing fluids with the reservoirs to minimize formation damage caused by the retention of fracturing liquid. In the "B" zone of Fig. 12, where the initial water saturation is higher than that of the "A" zone, the water absorption ability is weaker than that in the above situation. The water-block unlocking potential is between the "A" zone and the "C" zone in Fig. 12, which could be called the "transition zone", where the reservoir has the potential of water block and the unlocking potential of water block. The flow-back scheme should be developed according to the actual condition of the reservoirs to avoid the occurrence of water block.

The evaluation criterion of water-block unlocking proposed in this work is proposed in work, which is helpful to understand the basic mechanism. However, a more rigorous criterion needs further study to give a better guidance to accurate judgment for production.

5. Conclusions

1) The flowback ratio of a fracturing liquid in high-quality shale gas reservoirs is usually low and is controlled by the strong water absorption ability of the fractured shale gas formation. The absorption of fracturing liquid in the reservoir is mainly affected by micro-nano pores and fractures, the difference between initial water saturation and irreducible water saturation, the complexity of the artificial fracture network, abundance of organic matters, etc.
2) The unlocking of water block in a shale gas reservoir is dependent on the absorption ability, fracture density and initial water saturation. An evaluation criterion for water block unlocking is proposed based on water imbibition capacity, capillary potential, and fracture density. It can be used to evaluate the possibility of formation damage of water block. A high-quality shale gas reservoir has ultra-low water saturation, and pumped fracturing fluids could be absorbed into the matrix to unlock the water block.
3) A reservoir with strong water absorption capacity will enhance the formation energy after the fracturing liquid enters the reservoir. The shut-in is conducive to improving the production capacity of the reservoir.

Acknowledgments

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