Research Article

Analyzing Tight Sand Characteristics and Its Influence on Aqueous Phase Removal by Gas Displacement

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Tight sand gas is an important unconventional natural gas. Liquid filtration plays a main role in the formation damage. Flowback rate is closely related to the formation permeability recovery. Usually, the more flowback rate is, the better the permeability recovery is. In order to research the factors that influence the liquid flowback, the tight sand characteristics and gas displacement have been investigated. Some experiments were carried out, including porosity, permeability, XRD, casting thin section, SEM, stress sensitivity, rock expansion, and gas displacement. The results are shown as follows. Taiyuan formation has average high clay content than H8 formation. Illite is the main clay in Taiyuan formation; chlorite is the main clay in H8 formation. From the casting thin section, the rock has strong compression. Taiyuan formation has large pore. However, H8 formation mainly has small cracks. Through the SEM, there are many micro- to nanocracks as well as some pores in these two formations. In some cases, cracks penetrate the clays. From the permeability stress sensitivity, these tight sands have strong stress sensitivity. Permeability decreases quickly with increasing confining pressure. In the rock expansion experiment, the tight sand has less expansion rate compared with shale gas rock and volcanic gas rock. Rock expansion rate has positive relationship with clay content. In the gas displacement experiment, usually the higher the clay content, the lesser the liquid flowback. Some samples have high clay content. However, it has high flowback rate, which may account for good pore connection. Through the above study, the flowback rate has negative relationship with clay content and positive relationship with pore size, pore connection, and displacement pressure. In order to increase tight gas production in the study area, the formation should have high flowback rate and less liquid retention. Therefore, clay expansion preventing additives should be added into the fracturing liquid to reduce the liquid retention. The quick flowback should be implemented after hydraulic fracturing for reducing the interaction between liquid and rock. At the same time, the drawdown pressure should keep in a certain value to reduce stress sensitivity.

1. Introduction

With increasing energy requirement, unconventional natural gas attracts our attention [1–9]. Tight sand reservoirs belong to unconventional reservoirs and have low porosity and permeability [10–13]. Ordos basin has abundance of tight gas, such as in the Sulige area. Ordos basin is the second largest hydrocarbon-bearing onshore basin in China with an area of about 250000 km² [14]. Lots of work has been carried out to learn tight reservoir and to effectively develop it. The basic characteristic investigation is firstly necessary,

such as the mineral components and pore characteristics. In order to characterize the property of tight sand, many microscopic experiments have been carried out by previous research, such as casting thin section, scanning electronic microscope (SEM), and CT scanning [15–18]. Despite the microstructure investigation, the gas flowing in the micro- to nanopore is closely related to the production, which can be reflected through permeability.

Tight sand initial permeability which is usually less than 1 mD [19–22] has been widely researched [23, 24], especially the permeability stress sensitivity [25–28]. Different methods

FIGURE 1: The simple map of the study area. (a) China map; (b) the amplification map of the green part in (a).

have been used to measure tight sand permeability, mainly including traditional steady-flow permeability measurement and pulse-decay permeability measurement [29–33]. Traditional permeability measurement method was carried out by monitoring the fluid flowing rate passing through the sample. Under similar condition, the high-permeable sample has higher flowing rate than the one of low-permeable sample. Pulse-decay permeability measurement is according to monitoring the pulse-decay rate between two ends of sample. The quicker the differential pressure decay, the higher the tested sample permeability. The permeability under different water saturation has been investigated [34, 35]. Tight sand permeability can be estimated by other ways, such as mercury injection capillary pressure (MICP) and nuclear magnetic resonance (NMR) [36]. Many models have been provided to calculate the permeability through MICP experiment [37–40]. Low-field NMR has also been widely used to appraise the rock permeability [41, 42].

Due to the low permeability of tight sand reservoirs, the initial production is very low. The hydraulic fracturing method becomes a significant method to stimulate this kind of tight formation for realizing commercial production [43–47]. However, large amount of liquid retain in the formation after flowback [13, 48]. Thus, the reservoir permeability was damaged severely, which reduce the effective gas flowing during production [49–54]. The same water saturation in tight gas reservoir has more impact on permeability than conventional gas reservoir [55]. Permeability jail exists in tight reservoir. Permeability jail is that an interval has no gas and liquid permeability. Thus, decreasing the aqueous phase saturation is very important in tight reservoir. The removal of aqueous phase trapping has been researched by previous experts [56–58]. It shows that pressure drawdown higher than the threshold capillary pressure can remove

aqueous phase trapping. Permeability recovery is very important during flowback after hydraulic fracturing. Displacement experiment plays a significant role in appraising the liquid flowback rate and permeability recovery rate [59, 60]. Some researchers show that displacement plays more important role in a short period, and evaporation has great impact in the long period for aqueous phase removal in reservoirs [61, 62]. In order to better understand the displacement process, the liquid filling process should be paid attention. Pendular ring has more impact on gas flowing than the liquid filling, because liquid filling usually fill the smallest pores. Pendular ring can block the throat [63]. In the process of displacement, the smallest pores are unlikely displaced due to its high capillary force, which also has less contribution to the permeability. Enough gas drawdown pressure is necessary to penetrate the pendular ring for forming gas flowing.

In our paper, the tight sand characteristics have been investigated firstly and then its influence on the liquid flowback and permeability recovery. This research contributes to better understand the study area basic property and its influence on the flowback efficiency.

2. Samples and Experimental Methods

2.1. Samples. Tight sandstone samples were taken from the Upper Paleozoic Taiyuan and H8 formation in the Ordos basin of China. The simple map of research place was shown in Figure 1. The green part in Figure 1(a) is the study area, which is magnified as shown on the right picture. The H8 and Taiyuan formations are the main plays for tight gas production in Ordos basin. H8 formation in Sulige has been studied comprehensively. However, the eastern Ordos basin tight sand has been less researched. The eastern Ordos basin is full of tight gas. The effective development of natural gas in

TABLE 1: Main experimental samples.

Taiyuan formation	Shenmu	S20-1	S20-3	S20-4	S20-6	S30-2	S30-3	S126-2	S127-6
	Shuangshan	S96-1	S96-3	S96-5	S120-1	S120-2	S120-4		
H8 Formation	Mizhi	M47-2	M47-3	M47-5	M72-3	M72-4			
	Shuangshan	S108-5	S123-1	S123-3	S124-2	S133-4			
	Sulige	S15-1	S15-6	S25-4	S31-1	S31-2			

this area is very important to greatly increase the natural gas production [14].

The main experimental samples are presented in Table 1. The samples are from the Shenmu, Shuangshan, Mizhi, and Sulige area in Ordos basin. There are 6 samples from Taiyuan formation in the Shenmu area. There are 13 samples from the Shuangshan area, including 8 Taiyuan formation samples and 5 H8 formation samples. There are 5 samples from H8 formation in the Mizhi area. There are 5 samples from H8 formation in the Sulige area.

2.2. Experimental Methods. Experiments have been carried out to investigate the tight sand characteristics and its influence on the displacement behavior, including XRD mineral analysis, casting thin section, scanning electronic microscope, stress sensitivity, clay expansion, and nitrogen displacement. The detailed experimental methods were shown as follows.

Porosity and initial permeability has been measured before other experiments. Porosity was measured without confining pressure, and the pore pressure is about 0.8 MPa. Initial permeability was measured under confining pressure with 5 MPa and pore pressure with 0.25 MPa. The testing gas used in porosity measurement was helium. The testing gas used in permeability measurement was nitrogen.

XRD mineral analysis was used to calculate different mineral composition, such as quartz content, feldspar content, and clay content. Different kinds of clay content can be measured through this experiment.

Casting thin section can be used to differentiate the different mineral particles and pore and crack characteristics. Plane-polarized light can reflect the pore distribution. The connected pores were filled with blue material, so that it can be seen through optical microscope. Perpendicular-polarized light can reflect the mineral distribution, especially the particle-contacting characteristics.

Scanning electronic microscope (SEM) was used to reflect the pore and mineral characteristics. It can show much better picture than casting thin section, especially the clay microscope characteristics and small pores.

Permeability stress sensitivity was used to appraise the permeability change with confining stress. The permeability decreases during loading process and increases in the process of unloading. It is closely related to crack closure and pore compression, which is very important during oil/gas development. The pore pressure keeps 0.25 MPa. The confining pressure changes from 5 MPa to 25 MPa and then unloading from 25 MPa to 5 MPa. It can reflect the pressure loading loss and permeability recovery rate after unloading. The testing gas is nitrogen.

Sample expansion experiment was used to research the clay expansion characteristics during liquid filtration. Clay expansion usually damage the formation permeability. The sample preparation was shown as follows. Firstly, the sample was ground into 200~400 mesh number, whose diameter is about 38~75 μm . Taking 10g particles for experiment, compress it under axial pressure with 15 MPa for 15 min and then make it into column shape. During experiment, put the sample into the chamber and make liquid contact to the sample and then measure the expansion distance with time. Expansion rate is ratio between expansion distance and initial sample length. Testing liquid is distilled water.

Nitrogen displacement was carried out to investigate the permeability change with liquid saturation. The permeability increases with displacement time and with high displacement pressure. The samples are column shape. The samples were dried in the oven for 24 hours under 105°C before testing. The initial saturation was established by imposing the sample with fluid pressure of 25 MPa for 48 hours after the sample was vacuumized. The liquid was distilled water.

3. Results

3.1. Initial Porosity and Permeability. The porosity and permeability of samples were shown in Figure 2. Before experiment, the rocks were processed into cylindrical samples. The number of total experimental samples is 93. There are 36 and 57 for Taiyuan and H8 formations, respectively. In Figure 2(a), most porosity distributes among 5-10% of both Taiyuan and H8 formations, which is more than half of the total samples. The porosity of samples with 15-20% is less. It indicates that most samples remain low porosity. Simultaneously, the porosity of Taiyuan formation is no larger than 15%. In Figure 2(b), samples with 0.1-0.5 mD exceed half of the experiment samples. Permeability under 0.1 mD in Taiyuan formation is larger than that in H8 formation. It shows more low-permeability rocks in Taiyuan formation. There are less percent with permeability larger than 1 mD in Taiyuan formation and H8 formation. Through the analysis of porosity and permeability, it shows that low porosity and permeability is the characteristics of this area.

3.2. Minerals Component Analysis. From Figure 3, the quartz content in all samples is very high. Some samples even reach 91.2% and 91.6% in H8 formation, which is typical quartz sandstone. Most of the samples are lithic quartz sandstone, including all Taiyuan formation. The feldspar content is very small and can be neglected.

In Figure 4, the average total clay content (24.35%) in Taiyuan formation is larger than the average total clay

FIGURE 2: The distribution of porosity (a) and permeability (b) of samples.

FIGURE 3: The mineral composition of samples: (a) Taiyuan formation; (b) H8 formation.

content (15%) in H8 formation. The total clay content in Taiyuan formation can be as high as 31.6%. The total clay content can be as low as 3.6% in H8 formation.

For analyzing the influence of clays on formation damage, the percent of different types of clays is shown in Figure 5. In Taiyuan samples, the main clays are illite and illite/smectite mixed layer. Simultaneously, the illite content is the main component in Taiyuan formation, while the kaolinite and chlorite can be neglected. However, the content of different clays of H8 formation is extremely different with that of Taiyuan formation. Chlorite is much higher than other clays and is about half of the clays. The weight percent of illite/smectite mixed layer and kaolinite is very similar.

3.3. Casting Thin Section. The casting thin section was shown in Figure 6. In Figure 6(a), there is nearly no pore in this area. From its perpendicular-polarized light in Figure 6(b),

it is clear that the particles squeeze each other tightly and it belongs to concavo-convex contact. It indicates that this area endures strong compression force. In Figure 6(c), there are some large pores, which can be $154\mu\text{m}$. From its perpendicular-polarized light in Figure 6(d), it also shows that there are strong compression characteristics. In Figure 6(e), there is a large pore and clays exist near this pore, which is displayed with multicolor in Figure 6(f). In Figure 6(g), there are some pores and a big pore is located in the middle of this picture. From its perpendicular-polarized light, many particles exist in this area; the average particle size is about $369\mu\text{m}$.

In Figure 7(a), there are small cracks, which belong to an intergranular seam. Not all cracks are connected. From its perpendicular-polarized light picture in Figure 7(b), there are particles which were intersected by fracture. In Figure 7(c), there are some small cracks which are similar

FIGURE 4: Samples' total clay content.

FIGURE 5: The content of different clays: (a) Taiyuan formation; (b) H8 formation.

to Figure 7(a). In its perpendicular-polarized light picture in Figure 7(d), strong compression characteristics exist. In Figure 7(e), there are also intergranular seam and no large pores. From Figure 7(f), there are some illites. There is no pore in Figure 7(g). It indicates that this area is very tight. From its perpendicular-polarized light picture in Figure 7(h), it shows that strong compression appears.

3.4. SEM Analysis. The scanning electronic microscope (SEM) in Taiyuan formation was shown in Figure 8. In Figure 8(a), there are some nanocracks and micropores. Lots of illite and chlorite exist in this area. From Figure 8(b), some illite exist and there are microcracks, which can be as large as $1.8 \mu\text{m}$. The big crack penetrates the illite area. In Figure 8(c), there are many pores, which can be as large as 324 nm . In Figure 8(d), this area is full of illite. Two cracks penetrate this area. This big crack can be 718 nm . In Figure 8(e), there are three long cracks. The wide part of the big crack can be $6 \mu\text{m}$. In Figure 8(f), there are many pores, which are nearly

round. In Figure 8(g), there are big cracks, which intertwine with clays. Some cracks were filled with small particles. In Figure 8(h), there are many small cracks, which have a width of 36 nm . A big pore connected with crack, which has a width of 536 nm and a length of $1.3 \mu\text{m}$. In Figure 8(i), there are also many pores. The pore size can be 314 nm and 192 nm .

H8 formation SEM pictures were shown in Figure 9. There are many small cracks in Figure 9(a). One big crack can be 909 nm . There are some small pores. In Figure 9(b), there are lots of illites and two cracks appear in this area. The big pore located in the joint of two cracks has a width of $16.43 \mu\text{m}$. In Figure 9(c), there are lots of small pores. One pore can be 630 nm . Two cracks exist in Figure 9(d). The big crack has a width of 500 nm . In Figure 9(e), there are small cracks and illite. One big pore near clays has a diameter of $1.78 \mu\text{m}$. In Figure 9(f), there are many pores in this area, and one pore has a diameter of 390 nm . In Figure 9(g), there are some illites and a small crack which has a width of 284 nm . In Figure 9(h), this area is full of clays

FIGURE 6: The casting thin section: (a)–(e) belong to S20-5 and (f)–(h) belong to S96-3. The left picture and the right picture belong to the same area.

and cracks. The width of crack can be $1.83 \mu\text{m}$. In Figure 9(i), there are some pores and the diameter can be 801 nm .

3.5. Permeability Tress Sensitivity. Permeability stress sensitivity has been researched in many previous papers [64]. From Figure 10, it is clear that the permeability decreases quickly with increasing confining pressure. During the stress-releasing process, permeability could not recover to the initial permeability. When sample experiences second stress loading and unloading, the first unloading and second unloading nearly overlapped. All sample permeability has been changed into dimensionless permeability.

For further analysis of stress sensitivity, K_0 , K_{01} , and K_1 are shown in Figure 10, respectively. K_0 is the initial permeability at 5 MPa of first loading; K_{01} is the permeability at 25 MPa of first loading; K_1 is the permeability at 5 MPa of first unloading. Therefore, we can obtain the permeability loading loss from 5 MPa to 25 MPa as well as the permeability recovery loss from 5 MPa-25 MPa-5 MPa.

The permeability loading loss is defined as

$$\frac{K_0 - K_{01}}{K_0} \times 100\%. \quad (1)$$

FIGURE 7: The casting thin section: (a)–(e) belong to M72-5 and (f)–(h) belong to S123-1. The left picture and the right picture belong to the same area.

The permeability recovery loss is defined as

$$\frac{K_0 - K_1}{K_0} \times 100\%. \quad (2)$$

In Figure 10, the permeability loading loss is 71.3% and the permeability recovery loss is 40% in S20-6, which indicates that nearly half of permeability could not recover. In S30-3, the permeability loading loss is 75.5% and the permeability recovery loss is 36.1%. In S96-1, the permeability

loading loss is 66% and the permeability recovery loss is 36.8%. In S120-4, the permeability loading loss is 78.2% and the permeability recovery loss is 43%. Therefore, Taiyuan formation has strong permeability stress sensitivity.

In Figure 11, H8 formation has similar characteristics with Taiyuan formation. The permeability loading loss is 85.8% and the permeability recovery loss is 47.3% in M47-2, which also indicates that nearly half of permeability could not recover. In M72-4, the permeability loading loss is 87% and the permeability recovery loss is 59.1%. In S108-5, the permeability loading loss is 66% and the

FIGURE 8: The SEM picture: (a)–(c) belong to S30-2, (d)–(f) belong to S120-1, and (g)–(i) belong to S126-2.

permeability recovery loss is 26.4%. In S123-3, the permeability loading loss is 88.8% and the permeability recovery loss is 43.9%. It also shows severe permeability stress sensitivity damage.

3.6. Sample Expansion. The interaction between clays and fracturing liquid has strong impact on the formation damage. From Figure 12, volcanic rock has strong capacity for clay expansion. The expansion rate can reach to 50% in about 3 hours. Shale rock expansion nearly keeps constant at 1 hour in WFZ, which is about 30%. The LJP shale rock expansion is far weaker than the WFZ. It reached stability about 20 min, and its expansion rate is about 15%. Tight sand has less expansion capacity. All sample expansion rate is no larger than 20%. The expansion can quickly approach to constant in less than 1 hour.

In Figure 13, the relationship between expansion rate at 3 hours and clay content has been shown. Expansion rate has a positive relationship with the clay content. Volcanic rocks have strong expansion capacity due to its high clay content. Tight sand has weak expansion rate due to its low clay content.

3.7. Nitrogen Displacement. Displacement experiment has been used to appraise the aqueous damage removal capacity in laboratory, which can simulate the reservoir condition during the flowback or production process. Two types of displacement experiments have been tested, including displacement with time and displacement with different displacing pressure.

3.7.1. Displacement Efficiency with Time. The S20-4 displacement was shown in Figure 14(a). The permeability recovery rate increases with displacing time, and liquid saturation decreases with displacing time. At initial condition, the liquid saturation is 58.14% at 5 MPa displacement pressure and 67.85% at 7 MPa displacement pressure. The liquid saturation decreases greatly at beginning 0.5 hour, which reduced to less than half of initial liquid saturation. When displacement time reaches to 10 hours, the liquid saturation approached to 8.69% in 5 MPa and 5.13% in 7 MPa. At the same time, the permeability recovery rate increases to 67.53% in 5 MPa and 72.82% in 7 MPa. It shows that this rock has strong aqueous phase trapping removal capacity. The reason is that it has less clay content, which is only

FIGURE 9: The SEM picture: (a)–(c) belong to M47-3, (d)–(f) belong to S133-4, and (g)–(i) belong to S31-1.

11.5% from Figure 4. The sample S20-1 and S20-4 have similar mineral components because these two samples were taken from close area. From Figure 14(b), the displacement of S96-3 was shown. There are two displacement pressures, including 15 MPa and 20 MPa. The initial liquid saturation is 53.13% and 58%. At initial displacement time, the permeability nearly keeps constant. It shows that liquid decreasing has no impact on rock permeability. When displacement time reaches to 2 hours, permeability still keep stability at 15 MPa. However, the permeability increases at 20 MPa. It shows high pressure has more capacity for gas flowing. At last, the liquid saturation is 31.85% at 15 MPa and 31.84% at 20 MPa. However, the permeability recovery rate is only 0.4% at 15 MPa and 0.24 at 20 MPa, which can be neglected. The weak permeability recovery rate is closely related to the clay content, which is 31%. The more clay content is, the lesser the displacement efficiency is. In Figure 14(c), the displacement of S120-4 was shown. Three displacement pressures were chosen, including 7 MPa, 10 MPa, and 15 MPa. The liquid saturation change is similar among three displacing pressures. At last, the liquid saturation curves nearly overlapped each other. However, the permeability recovery rate is different. In the end, the permeability

recovery rate is 30.46%, 40.92%, and 55.89%, respectively. This sample has high flowback rate, which is caused by good pore connection.

In Figure 15(a), two displacement pressures were chosen for testing, including 10 MPa and 15 MPa. At initial time, the liquid decreases quickly. At 1 hour, the permeability has no increase at 10 MPa and a little increase at 15 MPa. At last, the liquid saturation is 39.28% at 10 MPa and 35.67% at 15 MPa. At the same time, the permeability recovery rate approach to 3.41% at 10 MPa and 6.07% at 15 MPa. This low flowback rate and permeability recovery rate may be caused by micro-nanopores. In Figure 15(b), there are three displacement pressures, including 3 MPa, 5 MPa, and 7 MPa. At 0.5 hour, the liquid saturation decreases greatly. The liquid saturation is 25.13%, 28.32%, and 27.38%, respectively. At the same time, the permeability recovery rate is 49.41%, 49.78%, and 50.12%. When displacement time reaches to 6 hours, the liquid saturation and permeability recovery rate nearly keep stability. At this displacement time, the liquid saturation is 10.23%, 9.51%, and 7.86%. The permeability recovery rate is 68.42%, 71.19%, and 76.75%. The high flowback rate is due to its relative low clay content, which is 18.2%.

FIGURE 10: Stress sensitivity of H8 formation.

3.7.2. Displacement Efficiency with Displacing Pressure. In Figure 16(a), the relationship between liquid flowback rate and displacement pressure was shown. Sample S15-6 and S20-4 have high flowback rate. It is closely related to the permeability. High permeability usually has high flowback rate. The flowback rate become stable at 15 MPa in S20-4, which is about 85.31%. Sample M72-3 and S123-1 have low flowback rate, because both have low permeability. The flowback rate is 21.66% and 22.42% at 10 MPa, respectively. However, sample S133-4 has relatively high flowback rate, even though it has similar permeability as M72-3 and S123-1. Its flowback rate can reach to 44.49% at 10 MPa. In Figure 16(b), the permeability recovery rate with different displacement pressure was investigated. Both S15-6 and S20-4 have high-permeability recovery rate, especially S15-6, which can reach to 95.63% at 7 MPa. There is no permeability increase in S120-4 when displacement pressure is less than 3 MPa. Both sample M72-3 and S123-1 have

similar permeability, so that the permeability recovery rate curve has similar characteristics. S133-4 has the lowest initial permeability, so that its permeability recovery rate curve is at the lower part. Therefore, displacement efficiency is closely related to the initial permeability and displacement pressure.

4. Discussions

Ordos basin has large amount of tight sand gas. Hydraulic fracturing has been carried out to exploit this kind of natural gas. However, there is severe aqueous phase damage due to its low permeability, which greatly influence its effective development. For better developing this type of natural gas in tight sand, the formation characteristics have been investigated as well as its influence on the fracturing liquid flowback and permeability recovery rate. Through XRD analysis, it shows that there are lots of quartz and clays, which make the wettability more water wet. Thus, the liquid retention is

FIGURE 11: Stress sensitivity of Taiyuan formation.

more severe, and high displacement pressure was needed to reduce aqueous phase, which make it more difficult to move the aqueous phase out of formation. For further understanding the microcharacteristics of tight sand, both the casting thin section and scanning electron microscope have been used to reflect the pore characteristics and particle contact characteristics. The different pores and cracks can be shown in casting thin section, usually the microscale. Pores and cracks were filled with blue color. In Taiyuan formation, there are many big pores, which is beneficial to gas flowing and gas displacing liquid during flowback. There are lots of micro-nanocracks, which are sensitive to stress. The cracks are likely close during development, which was simulated in laboratory by permeability stress sensitivity. The permeability decreases quickly at the early loading process and damages greatly when confining pressure reach to subsurface pressure. More than half of the permeability has lost. It indicates that the productivity will be influenced greatly

when the reservoir gas pressure decreases during production. After the permeability damage, even though the gas pressure increases to the initial condition, there is still severe permeability damage, which was simulated by the unloading process. This phenomenon indicates that once the microcracks closed, it is difficult to reopen again. This characteristic shows that the reservoir should keep the gas pressure during the production by injecting other gas. During unloading process, the permeability can increase gradually. When confining pressure return to the initial condition, the permeability increases greatly. It shows that permeability can increase by injecting gas after reservoir endures permeability loss by production process.

The gas displacement behavior is closely related to reservoir characteristics, and the efficiency for displacing the fracturing fluid out of formation has relationship with clays. Through the sample expansion experiment, it can be found that the sample expansion rate has positive

FIGURE 12: Sample expansion with time. JL306-4, JL303-7, and DS11-3 belong to volcanic gas sedimental rock; WFZ and LMX belong to shale gas rock.

FIGURE 13: The relationship between expansion rate at 3 hours and clay content.

relationship with the clay content. Tight sand has less expansion rate when it is compared with volcanic gas rock and shale gas rock. Therefore, it has less formation damage caused by the clay expansion. During nitrogen displacement experiment, different clay percent has been considered. In most cases, the more clays the samples have, the more damage the formation will be. It means that there is less

liquid flowback and less permeability recovery rate. The initial permeability has greatly influenced the liquid flowback. Usually, the larger the initial permeability, the higher the liquid flowback and permeability recovery rate. Some samples have similar initial permeability. However, there are different liquid flowback rate, which is likely caused by the different pore network.

FIGURE 14: The variation of liquid saturation and permeability recovery rate with displacement time in Taiyuan formation. Confining pressure is 25 MPa.

FIGURE 15: The variation of liquid saturation and permeability recovery rate with displacement time in H8 formation. Confining pressure is 25 MPa.

In order to further analyze the influence of porosity and permeability on fluid flow in rocks, the FZI* flow zone indicator was analyzed. The equation of FZI* is shown as follows [65, 66]:

$$\text{FZI}^* = 0.0314 \sqrt{\frac{k}{\phi}}, \quad (3)$$

where k is the permeability in mD and ϕ is the porosity in fraction.

In Figure 17, the sample FZI* was shown, and it varies from $0.033 \mu\text{m}$ to $0.126 \mu\text{m}$. The higher the FZI* is, the better the fluid flow in rock is. This indicator has good relationship with the permeability recovery rate in Figure 16. Sample S15-6 has high-permeability recovery rate, which can reach to 95.63%, and it also has high

FIGURE 16: The variation of liquid flowback rate and permeability recovery rate with different displacement pressure. Confining pressure is 25 MPa.

FZI*, which is $0.125 \mu\text{m}$. Sample S20-4 has the permeability recovery rate of 85.31%, and it has the FZI* of $0.116 \mu\text{m}$. Sample S133-4 has low permeability recovery rate, and it has the low FZI*, which is $0.046 \mu\text{m}$. Therefore, the higher the FZI* is, the higher the permeability recovery rate is.

Through our research, in order to increase the fracturing fluid flowback rate and permeability recovery rate in the process of hydraulic fracturing, the initial permeability, clay

content, pore types, and pore connection should be given special attention.

5. Conclusions

Tight sand gas plays a very significant role in unconventional resources. Ordos basin is full of tight gas. However, there is severe aqueous phase damage during drilling, fracturing, and so on. Even though by flowback behavior, there

FIGURE 17: The FZI* of samples.

is still large amount of liquid retaining in the formation. In order to research this behavior, many experiments were carried out, including tight sand property and nitrogen displacement. The detailed conclusions were shown as follows.

- (1) Taiyuan formation has big pores and strong compression among particles. There are lots of micro-cracks, which is prone to close during increasing stress. There are lots of small cracks in H8 formation. Usually, these cracks are too narrow, so that strong permeability stress sensitivity appears during loading process
- (2) Tight sand has strong permeability stress sensitivity. In most cases, the permeability decreases greatly when confining pressure changes from 5 MPa-25 MPa. More than half of the permeability has been damaged. After the confining pressure reduced to the initial confining pressure (5 MPa), there are still large amount of permeability being lost
- (3) Tight sand has weak rock expansion characteristics, when it was compared with shale rock and volcanic rock. This characteristic own to its low clay content. The rock expansion rate is consistent with the clay content. The more clay is, the more severe the sample expansion rate is
- (4) Through nitrogen displacement experiment, in most cases, the flowback rate and permeability recovery rate have negative relationship with clay content and positive relationship with initial permeability

Based on above research, clay expansion preventing additives should be added in the fracturing fluid to prevent clay expansion, reduce fluid retention into formation, and increase permeability recovery rate after flowback. When it comes to low permeability formation, preventing liquid filtration is a better choice, because not enough displacement pressure can be obtained. For relative high-permeability formation, quick flowback is a good choice to move liquid out of

formation and increase permeability. Our research contributes to better understand the formation characteristics and its influence on the gas displacement to remove aqueous phase trapping.

Data Availability

The data used to support the findings of this study are included within the article.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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