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Controlling effect of fractures on gas accumulation and production within the tight sandstone: A case study on the Jurassic Dibei gas reservoir in the eastern part of the Kuqa foreland basin, China

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Abstract

Using Dibei tight sandstone gas reservoir in the eastern part of the Kuqa foreland basin as an example, this paper discusses tight sandstone reservoir fractures characterization, its effect on storage space and gas flow capacity, and its contribution to gas accumulation, enrichment and production in tight sandstone reservoir by using laser scanning confocal microscope (LSCM) observation, mercury intrusion capillary pressure (MICP) testing, and gas-water two-phase relative permeability testing. The statistics of laser scanning confocal microscopy observation showed that the microstructural fractures width in the Dibei gas reservoir was mainly 8–25 μm, and the associated micro-fractures width was mainly 4–10 μm. Additionally, the throat radius was mainly 1–4 μm. The fractures width was significantly wider than the throat radius that served as the main channel of in gas flow. In addition, it illustrated that the samples with developed fractures became easier for gas to flow under equal porosity condition, because of lower expansion pressure, higher mercury injection saturation, and increased gas relative permeability based on the physical simulation experiment of gas charging into core samples with saturated water, mercury injection and gas-water two-phase permeability experiments. Furthermore, it had been concluded that the fractures control tight gas in the following aspects: (1) Fractures play a significant role in reservoir property improvement. The isolated pores were linked by the fractures to form connective reservoir spaces, and dissolution is prone to occur along the fractures forming new pores. The fractures with bigger width are reservoir space as well. (2) Fractures increased fluid flow capacity because it decreased the starting pressure gradient, and it increased gas effective permeability. Thus, fractures improved the gas injection efficiency as well as gas production. (3) Fractures that developed in different time and spatial places have different effects on gas accumulation, enrichment, and production in tight sandstone reservoirs.

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Keywords: Fracture; Tight sandstone gas; Fluid flow; Starting pressure; Relative permeability; Gas accumulation and enrichment; Dibei gas reservoir

1. Introduction

Tight sandstone gas became the most practical area for global exploration and development of unconventional hydrocarbon resources, due to abundance in gas resource distribution, giant reserves, close relationship with the
exploration, development methods of conventional hydrocarbon resources, and realization of short-term progress [1–3]. Nevertheless, the complex geographical features, which are different from the conventional reservoir, made the efficient and economical exploite of tight sand gas extremely difficult. Therefore, it is of great importance for determining the controlling factors on gas-bearing capacity of tight gas reservoir and “sweet spot” distribution regulation. Scholars [4–6] usually define the function of fracture in tight sand gas resources generally as what increase the fluid flowability of a reservoir to form “sweet spot”, which is helpful for gas accumulation. Be that as it may, the function of fracture in tight sand gas is far more than this. It controlled gas accumulation, enrichment and production of tight sand gas. This paper, taking Dibei tight sandstone gas reservoir in the eastern part of the Kuqa foreland basin as the study case, gives a systematic research and discussion with the influence mechanism of fractures on reservoir spaces, seepage ability in tight sandstone reservoirs, as well as analysis of controlling effect on tight sandstone gas reservoirs accumulation, enrichment, and production.

2. Geological background of the Dibei gas reservoir

The Dibei gas reservoir is located in the south-dipping fault nose slope zone in the central Yiqikelike tectonic zone in the eastern Kuqa foreland basin (Fig. 1). It’s characterized by tight reservoirs, superimposed source rocks and reservoirs, gas-water inversion, abnormal pressure, and the strong sealing capacity of cap rocks [7,8]. Strong tectonic deformation occurred in this zone after the deposition of Cretaceous Shushanhe Formation, resulted in the absence of Upper Cretaceous top Baxigai Formation and Bashijiqike Formation, forming the Yiqikelike anticline zone. Then, a distinct tectonic slope background formed along with the significant uplift in the northern strata due to the strongly compressed thrust of the Tianshan Mountains since the Kuqa stage. The main gas source rocks of the gas reservoir were the Triassic Taliqike Formation and the Huangshanjie lacustrine hydrocarbon rocks, which were characterized by high organic abundance, III-type kerogen and high thermal evolution [9], they provided an adequate material basis for tight sandstone gas. The tight reservoirs of the Jurassic Ahe Formation were closely linked with underlying Triassic hydrocarbon rocks. The coal-bearing stratum the overlaid Yangxia Formation acted as a good cap rocks. These elements contributed to the favorable source-reservoir-cap rock combination. The sandstone reservoir of the Ahe Formation has a wide distribution; however, by deposition, diagenesis and structural fractures reservoir has strong heterogeneity and complex gas-water distribution.

The sandstone reservoirs of the Yangxia Formation were similar with those of the Ahe Formation in terms of the reservoir’s physical properties and sedimentary environments. Nevertheless, they were not regarded as major target strata due to their insufficient thickness.

3. Samples and methods

This research investigated the fractures’ characteristics and its effects on storage space of tight sandstone reservoir in the Dibei gas reservoir of the Kuqa Depression by using laser scanning confocal microscope (LSCM) observation, mercury intrusion capillary pressure (MICP) testing, and gas-water two-phase relative permeability testing. Samples were mainly collected from the Dibei area, and some were collected from other areas of the Kuqa foreland basin. Laser scanning confocal microscope (LSCM) observations were conducted in the Key Laboratory of Basin Structure and Hydrocarbon Accumulation, CNPC in Beijing. Foremost, representative tight sandstone samples were processed to cast thin section. The injection material was special, and it can emit fluorescence under laser scanning conditions. We observed and analyzed the fracture size and distribution. Mercury intrusion capillary pressure (MICP) testing was carried out in the Key Laboratory of Natural Gas Development of Langfang Branch of RIPED, PetroChina. Fresh tight sandstone samples were chosen and tested via MICP using auto pore 9410 porosimeter, manufactured by Micromeritics. The working pressure was 0.0035–206.843 MPa. Concurrently, the resolution was 0.1 mm. Physical simulation experiments were conducted also in the Key Laboratory of Basin Structure and Hydrocarbon Accumulation, CNPC in Beijing. Required sample size was ø2.54 cm and 3–8 cm of core plugs as a length. Samples were pre-treated before the experiment in accordance with national standards SYT5336-1996, and its gas porosity and permeability were measured. An experimental installation of physical simulation was composed of four parts, namely, fluid injection system, temperature control system, fluid output metering systems, and data processing systems. The experiments carried out at room temperature, with helium gas as the injection gas and pure water as the saturated core test water. Experimental injection pressure was at 1–10 MPa, confining pressure within the range 3–15 MPa. The experimental procedures are listed as follows: (1) The core plug was placed into the core holder and its both ends were tightened, then the inlet was connected to the gas source while the outlet was connected to the gas-water separator and flow recording system. (2) The loaded confining pressure was about 3 MPa, the confined pump mode was changed to tracking mode. The confining pressure varies with inlet pressure and it should always be greater than the inlet pressure of 3 MPa. (3) Adjust the regulator in order for the gas source to be opened. Then, observing the fluid metering system until the fluid production appears in output. Recording the pressure of inlet and outlet ends and quantitative of fluid production when the fluid flow rate remains constant. Adjusting the pressure valve to increase the inlet pressure and keep it for a while, then recording the pressure of inlet and outlet and the fluid production until the production cannot increase any more. Thus, the experiment is finished. Gas-water phase relative permeability experiment was performed according to oil and gas industry standards,
Fig. 1. Top-surface structural map for the Jurassic Ahe Formation and geological profile of the Dibei gas reservoir.
and it was conducted in the Key Laboratory of Basin Structure and Hydrocarbon Accumulation, CNPC in Beijing. The core samples’ preparation was in accordance with the criteria conventional core analysis methods.

4. Results

4.1. Petrological features

The main rock types in the Dibei Field were litharenite, secondary rocks types is feldspar lithic sandstone. The average content of quartz was 33.9%—46%, and the average content of feldspar was 5.2%—16.2%. Rock debris was 41.3%—53%, in which it’s primarily composed of metamorphic rock debris, and the rest being magmatic rock debris and sedimentary rock. The grains of the rock were generally coarse, with conglomerate; it was chiefly comprised of coarse sandstone gravel and anisomerous sandstone. The texture maturity of the rock remained at mid-level with point-line and concave-convex-line contact among grains as the majority, and the cementation types dominated by porous cementation, contact cementation and mosaic cementation. The interstitial material content is 6.85%—9.51%, it mainly consisted of the matrix. The matrix mainly included argillaceous and iron clay montmorillonite. Iron clay montmorillonite contains a small amount of cement, which mainly includes silicic cementation and calcite cementation.

4.2. Physical characteristics and pore types

The main reservoir space types of the Dibei Field are intragranular dissolved pores, intergranular dissolved pores, argillaceous micro-pores and micro-fractures, its primary intergranular pores is rarely seen [10]. According to the statistics of casting thin sections, the argillaceous micro-pores accounted for 45%—55% of the total pores, intragranular dissolved pores and intergranular dissolved pores came next with 24% and 21%, respectively. Micro-fracture occupied only around 5%. The matrix porosity of reservoir varied between 0.3% and 15.63%, the mean value is 7.1%. Reservoir permeability range is (0.002—2670) × 10⁻³ μm², its mean value is 0.75 × 10⁻³ μm², obviously, the reservoirs belongs to low permeability and low porosity reservoirs [11].

4.3. Fracture distribution and development

Fractures are extensively development in tight sandstone reservoirs of this region. Observation of the outcrop sections and cores suggested a large amount of high angle shear tectonic fractures, and quantities of micro-fractures were also discovered in reservoirs through observation of thin sections of sandstone samples in micro scale. Effective fracture network system (Fig. 2) is formed in combination with the tectonic fractures and associated micro-fractures, connecting the micropores of the reservoirs, forming significant fluid flow channels and reservoir spaces in tight reservoirs, and it is a key element in the enrichment and production in the Dibei gas reservoir.

4.3.1. Distribution regulation of tectonic fractures

The development degrees of tectonic fractures vary in different parts of the structure belt because of the variation of stratum thickness, lithological combination, and relevant tectonic stress [12—15]. Under the influence of the Himalayan tectonic movement, thrust nappe structures in varying scales developed in the eastern Kuqa. The outcrop section and core observation showed that fractures were greatly developed in the axis of the anticline and hinge zone, followed by those in some local hinge zones of the flank bed or the positions with a large curve. Fractures developed within fault zones, and those in the hanging wall were more developed than those in the footwall [15]. In the plane, the tectonic fractures were most developed at Well YN2-Well DB104 distributed along the tectonic axis. Fractures in Well YN2 were mainly high angle tectonic fractures with a fracture surface density of 9.03 m⁻¹; the tectonic fractures in Well DB101 and Well YN5 in the slopes were less developed. Furthermore, Fractures in Well YN5 were mainly low angle oblique fractures and horizontal fractures with a fracture surface density of 0.71 m⁻¹ [15].

4.3.2. Features of micro-fracture development

Three types of fractures were classified according to the relative position of micro-fractures and mineral particles, they are the cross-inter-particle fracture, inter-particle-margin fracture and intra-particle fracture respectively [16]. All three types of fractures were discovered in Dibei Jurassic gas reservoir in the eastern part of the Kuqa through microscopic observation of a large amount of casting thin sections (Fig. 2). Cross-inter-particle fractures were usually extended in large-scale without limitation of mineral particles. Affected by tectonism, they often cut multiple rock particles with a certain trend. The fractures developed from micrometer scale to several meters scales, which showed a large range scale. Meanwhile, micro-fractures were found using microscopes, or as smaller associated micro-fractures besides large fractures. All of the aforementioned fractures formed fracture networks. Inter-particle-margin fractures developed along the particle edges between mineral particles which develop as line contact. Inter-particle-margin fractures were formed because of the change of rock inner stress because all of the pores in the sandstones were nearly all destroyed during the compaction process. The particles were mostly line toconcave convex cpmtact, afterwards, inter-particle-margin fractures were formed along the radiuses of particles decreased due to the uplifting and cooling of the stratum in later periods [17]. This kind of fractures was the main type of fractures in the Dibei gas reservoirs, this caused the widely developed inter-particle-margin fractures to be connected with one another (Fig. 2). Therefore, they are vital in the improvement of reservoir physical property and seepage ability. Intra-particle fractures developed inside the rock particles, not cutting through particle edges, with small scales, short extend distances, which formed under diagenesis compaction.
5. Discussions

5.1. Relationship between fractures and reservoir spaces

The effective porosity of conventional reservoirs was slightly lower than the total porosity. Whilst the effective porosity dramatically decreased in tight sandstone reservoirs because of the strong diagenesis, this also leads to the complexity and variation of structure and type of rock pores [18]. Fractures play a significant role on improving tight reservoir spaces and pore-throat structures.

5.1.1. Fractures connected the isolated micro-pores

A lot of pores, were formed because of dissolution of intergranular cement, rock fragments, and mineral grain in tight sandstone reservoirs, usually they behaved as isolated pores [3]. Although hydrocarbon contained in these pore, they almost cannot extracted from these isolated pores under current technical conditions. Few primary pores were found in the Jurassic Dibei gas reservoirs in the eastern part of Kuqa. Secondary pores were mainly calcite cement, dissolution pores in potash feldspar and acidic volcano rock debris, and argillaceous matrix dissolution pores. Micro pores which existed
isolately in argillaceous and mineral without effective connection [10]. Micro pores have great difficulty in forming effective reservoir spaces. Cross-inter-particle fractures, inter-particle-margin fractures, and intra-particle fractures formed in the later period, they connected the isolated intragranular and intergranular micro holes (Fig. 2), which formed connective reservoir spaces in tight sandstone reservoirs. Thus, they increased effective porosity as well as improved reservoir physical property.

5.1.2. Secondary dissolution pores increased reservoir spaces

It was discovered through observation of quantity of casting thin sections in the Dibei Jurassic tight sandstone gas reservoir that the intragranular and intergranular dissolution pores developed along fractures, and the dissolution pores presented directional distribution along fractures (Fig. 3). Due to the limited fluid flow spaces, the water–rock interaction was reduced after strong compaction and cementation that eventually lead to the decrease in the possibility of dissolution. The existence of tectonic fractures formed connective flowing channels to make fluids and mineral fully contacted, dissolution, and took soluble substance away, after which the secondary dissolution pores formed. This increased the reservoir spaces and significantly improved reservoir physical property.

5.1.3. Fractures provide the spaces for gas accumulation and flow

A considerable amount of measurements and statistics were carried out based on the observation the fracture width and throat radius of casting thin sections of the Jurassic tight sandstone reservoir in the Dibei Gas Field by laser scanning confocal microscope. 3700 data of 14 layers in 3 wells are obtained. According to the analysis of statistical data, the micro fractures' average width radius ranged 4–280 μm, mainly distributed in 8–25 μm. The associated micro fractures' width radius 1 range in 2–25 μm, mainly varied in 4–10 μm. The throat radius ranged within 1–12 μm, mainly

![Fig. 3. Dissolution pores grow along the fractures. (a) Well YN2C, 4759.01 m, J1α, coarse-grained lithic sandstone, minerals mainly consist of quartz and feldspar, potassium feldspar intragranular dissolution pores present directional distribution, polarized light images, ×50; (b) Well YN4, 4575.64 m, J1α, conglomerate, polarized light images, intragranular dissolution pores occurrence in potassium feldspar particles, ×50; (c) Well YN5, 4534.6 m, J1β, glutenite, pores mainly include acidic volcano rock debris dissolution pores and feldspar intragranular dissolution pore, followed by clay matrix intergranular dissolution pores, polarized light images, ×50; (d) Well YN2, 4550.5 m, J1β, minerals mainly consist of quartz and feldspar, intragranular dissolution pores occurrence in potassium feldspar particles, polarized light images, ×25.](image)
focused on 1–4 μm (Fig. 4). This implies that the fractures’ width is wider than the throat radius to a large extent. The feature improved fluid flow capacity, and it also became an effective storage space for tight gas.

5.2. Influences of fractures on gas seepage

5.2.1. Existence of fractures decrease starting pressure gradient

The gas migration and accumulation pattern in the conventional reservoir follows the classic Darcy’s Law, but the said law can’t be applied properly to tight sandstone reservoirs, for the complex structure of the reservoir pores. Complicated pore structures changed the flow capacity in tight sandstone reservoirs, making it no longer conform to Darcy’s law. Gas flow and pressure presented as non-linear relationship [19,20], and gas cannot flow only to reach a certain starting pressure gradient. The physical simulation experiment of gas charging into core samples with saturated water was made for 10 sandstone samples (Table 1) from central and eastern Kuqa. The experiment was completed through the instruments that were independently designed, researched, and developed by the Research Institute of Petroleum Exploration & Development (RIPED), PetroChina. The pretreatment sample and the porosity and permeability determination were made in accordance with the national standard SYT5336-1996 prior the experiment. The experiment was executed at room temperature and within the pressure range 0–8 MPa. In order to avoid the effects of gas adsorption on the results, the inert gas helium was used in the experiment. Loading the confining pressure of 3 MPa, setting the confining pump mode as tracking mode so as to the confining pressure increased with the inlet pressure, and it was always higher than the inlet pressure by 3 MPa. This helped to prevent the gas from channeling along the wall in between core samples and holder; it also ensured that the gas passes through the section of samples.

The results of the experiment are as shown in Fig. 5. The first sample, belonging to the conventional sandstone, had

![Fig. 4. Relationship of structural fractures, associated micro-fractures, and throat radius distribution.](image-url)
21.4% of porosity and 528 mD of permeability. The sample needed no starting pressure gradient for injection, and the gas flow rate directly increased sharply with the increase of injection pressure, this made the Darcy’s Law applicable.

The third sample, with a necessary starting pressure gradient for migration of 0.05 MPa/cm, has a porosity of only 3.4%, while the permeability reached 2.18 mD. Despite the fact that sample 9 has a porosity of 5.4%, the permeability is only 0.2749 mD because of the lack of fracture. The 9th sample needed a starting pressure gradient of 0.23 MPa/cm, nearly five times of that of sample 3rd. The starting pressure gradient of sample three is the least of all the ones with fracture lacking, or with fracture and fully filled. Sample 3rd can only achieve the flowing stage of Darcy quickly by comparison. According to the experimental results, no starting pressure gradient was needed for gas migration in the conventional sandstones; this phenomenon was in accordance with Darcy’s Law. Meanwhile, for tight sandstones, the lower the reservoir permeability is, the greater the requirement for starting pressure gradient of gas migration [21]. At the situation of equal porosity, the starting pressure gradient of sandstones with non-filled or half-filled fractures was lower than that of sandstones with no fracture or full-filled fractures. This suggested that fractures helped decrease the starting pressure gradient of tight sandstone and to promote gas injection.

5.2.2. Impacts of fractures on displacement pressure of tight sandstone reservoirs as well as hydrocarbon saturation

Mercury injection curves of the two pieces of typical sandstone samples from Ahe Formation, Well Yina 2 are as shown in Fig. 6. Sample ① has a porosity of 4.5%, permeability of 0.211 mD, displacement pressure of 1.019 MPa, and maximum mercury injection saturation of 48.25%. Sample ② is more compacted tight sandstone sample with a porosity of 3.9%, having a high permeability of 74.6 mD, low displacement pressure of 0.031 MPa, and high maximum mercury injection saturation of 60.16% due presence of the fractures. This implied that the fractures, as advantage seepage channels, decreased the displacement pressure of tight reservoir effectively and link isolated micropores, which sooner or later...
improved mercury injection saturation that helped gas injection. Gas is capable of entering tight reservoirs; this enables it to form a continuous migration phase within the fractures more easily and faster. This definitely shortened duration and improved the efficiency of hydrocarbon accumulation thus increasing hydrocarbon saturation.

5.2.3. Impact of fractures on relative permeability of gas and gas seepage

The presence of multiphase fluid flow in rocks, it will have a mutual influence and interaction, under these circumstances, effective permeability of gas in tight sandstone reservoirs became the key point. Contrary to the conventional reservoirs, the range of gas-water two-phase fluid flowing together is relatively small in tight reservoirs, even permeability jail [6] existed where neither gas nor water could flow. As Fig. 7 shown, two permeability curves are different; they are from two samples of well YN2. The sample (Fig. 7a) with no fracture has a porosity of 6.4% and a very low permeability of 0.043mD, this reflects the poor pores connectivity of the sample. As the curves demonstrate, the relative permeability of gas went as low as 0.2 due to the existence of residual water in the pores. The maximum gas saturation was 41%, and the range for gas-water two-phase fluid to flow simultaneously was extremely small. Furthermore, with the existence of fractures in the sample (Fig. 7b) its permeability reached 0.71mD, this was 17 times of that of the sample (Fig. 7a), despite the porosity being only 3.47%. The relative permeability curves showed that the relative permeability of the sample (Fig. 7b) dramatically increased to nearly 0.6 in the situation wherein residual water is present. The maximum gas saturation increased to 50%, and the range for gas-water two-phase fluid flowing simultaneously amplified.

Influences of fractures on relative permeability curves of the tight reservoir can be shown more clearly by superposition of the relative permeability curves of the two samples to one figure (Fig. 8). Existing fractures may change the migration of gas-water two-phase fluid in tight sandstone reservoirs, thus raising the effective permeability of gas, enlarging the maximum gas saturation of tight sandstones to some extent [22,23], benefiting the formation of “sweet spot” and improving gas production.

5.3. Fractures’ controlling effects on accumulation, enrichment and production of tight sandstone gas

Fractures developed in different time and space, thus its controlling effects on the gas accumulation enrichment gas are varying. Fractures formed earlier or at the same time as gas charging into tight sandstone, fractures greatly improved the gas charging accumulation efficiency in tight sandstone reservoirs. The massive development of fractures in tight sandstone reservoirs formed a fracture network system and this divided reservoirs into several small accumulation units. During gas migration, the initial step begins once it enters into the fracture network space, greatly increasing the effective space of gas charging. This was conducive to efficient charging and formation of high gas saturation [24]. A typical example is a large number of tectonic fracture formation period was almost simultaneous with gas charging period in DB and KS gas fields in Kuqa thrust zone. Over-pressure gas charging was efficient in the conducting mechanism of the fracture network system. Deep pre-salt tight reservoirs were extremely efficient gas reservoirs with a gas saturation of up to 60%—70% [25]. Whenever the tectonic fracture formation period came much later than the gas charging period, fractures played the role of restructuring the prototype tight sandstone gas reservoirs [4]. At that time, the location where fractures developed controlled the
degree of fracture restructuring of tight sandstone gas reservoirs. When the fracture system developed at the top boundary of tight gas reservoirs it destroyed the force equilibrium of the gas at the boundary of gas reservoirs, which resulted in gas leakage. The gas leakage caused atrophy of tight sandstone gas reservoirs, and fractures were destructive to tight gas reservoirs \[4,26\]. Thus, resulting in the decline in gas yields, or even non-attainment of standards for commercial oil and gas production, such as well YN4 and well YS4 located in the high tectonic part. Testing results showed that they were gas-bearing or water strata, but the fluid inclusions and grain fluorescence evidence showed the occurrence of gas charging and accumulation in this region in geological history \[7,8\]. This was due to its proximity to the Yiqikelike fault. The connection of fractures damaged tight gas reservoirs, brought about massive loss of gas, decrease in gas saturation and increase in water saturation. When fractures developed within the prototype gas reservoirs, they played the role of restructuring the gas accumulation. By improving the storage space of tight sandstone reservoirs, it enhances the fluid flowability in reservoirs by allowing gas to form a “sweet spot” in fracture development zones \[27–29\]. Fractures ultimately control the high yield of tight gas. Dibei gas reservoirs developed in the background of slope zones. The current exploration showed that the “sweet spot” with high gas saturation only formed near YN2 anticline and high yields were achieved in Well YN 2, Well DX1, and Well DB104. Drilled at the main part of YN 2 anticline, while Well DB101 and Well DB102 outside the anticline, presented low yields. Well YN5 and Well DB1 further away from the anticline failed to get gas production. The analysis showed that the main cause was the control on gas accumulation by the development degree of later fractures. A fault nose structure was formed in Well YN2 under the regional thrust compressive tectonic effects, and massive fractures developed at the hinge zone of the fault nose subsequently formed a “sweet spot”. The observation and measurement of the drilling core showed that Ahe Formation fracture surface density of Well YN2 was 7.03/m. The fractures were dominated by high angle heterotrophic fractures and vertical fractures which were mostly unfilled or half filled. The fracture surface density of Well YN5 which located in a relatively stable region was only 0.71/m, and the fractures were dominated by low-angle fractures and horizontal fractures which were mostly filled. As a result, Well YN2 presented a high yield of up to 40–70 thousand m\(^3/d\), while Well YN5 was non-production well. The comparison showed that the greater the fracture density is, the higher the gas yields (Table 2) are. Well DX1 and Well DB104, are located at the main part of YN2 anticline, have relatively developed fractures with great density and yield reached up to 580–720 thousand m\(^3/d\). In comparison, the fractures of Well DB101 and Well DB102 at the side of the anticline were of low density and the yield decreased to 2–6 m\(^3/d\). In the same well, it presented higher gas saturation and yields in fracture development sections. Taking Well YN2 as an example, the degree of fracture development was positively correlated with gas saturation. Tectonic fractures were well developed at well sections 4810–4870 m, and the corresponding sections presented higher gas saturation \[4\].

### 6. Conclusions

(1) Tight sandstone reservoirs and fractures were universally developed in the Dibei Jurassic tight sandstone reservoirs in the eastern part of the Kuqa foreland basin. The reservoirs' throat radius generally varied within the range of 1–4 \(\mu\)m, and fractures' width radius within the range of 4–25 \(\mu\)m. The fractures play an important role on controlling reservoir pore spaces, fluid flow, and tight gas enrichment and production.

(2) Fractures influence the storage spaces from the following aspects. Isolated pores are linked by fractures to form connective reservoir spaces in tight reservoirs; secondary dissolution pores were developed through fractures, this increased the storage spaces; fractures also provided space for gas migration and accumulation.

(3) Fractures affect the seepage ability of gas in the following aspects. Fractures effectively decreased the starting pressure gradient of gas migration in tight sandstone reservoirs, it is eventually favorable for gas injection; the tight reservoirs' displacement pressure was decreased while hydrocarbon saturation was increased because of fractures existence; enlarging the range of two-phase fluid flow simultaneously in the reservoirs, and improving the gas effective permeability.

(4) Fractures development improved the gas charging and accumulation efficiency in tight sandstone reservoirs in the situation that fractures form prior or at the same time as gas charging; while adjustment and reform of the prototype tight sandstone gas reservoir were carried out when fractures formed later than gas charging. Gas reservoirs may be destroyed and resulted in atrophy of tight sandstone gas reservoir when fracture developed at the top boundary of tight gas reservoirs, while the “sweet spot” will be controlled by fractures when fractures developed inside the prototype gas reservoirs.

### Table 2

<table>
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<tr>
<th>Well</th>
<th>Thickness of Ahe formation/m</th>
<th>Fractures for imaging logging interpretation/(pieces/m)</th>
<th>Fracture density/(pieces/m)</th>
<th>Daily gas production/(m(^3/d))</th>
<th>Daily oil production/(m(^3/d))</th>
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Conflict of interest

The authors declare no conflict of interest.

Foundation item

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