Research Article

Genetic Types and Main Control Factors of Microfractures in Tight Oil Reservoirs of Jimsar Sag

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Microfractures are key for migrating and aggregating hydrocarbon source rocks and fracturing oil-gas exploitation in tight reservoirs. In this study, rock samples from the Lucaogou Formation tight reservoirs in Xinjiang, China, were studied using multidisciplinary techniques to investigate the genetic types and main control factors of microfractures. Results indicated that the Lucaogou Formation mainly developed diagenetic microfractures followed by tectonic microfractures, with slight formations of granular microfractures. These observations were used to clarify the relationship between the development of microfractures and the pore fluid content, lithology, mineral composition, and stratum thickness. A higher pore fluid content corresponded to a lower compressive strength of the rocks and a larger ring count, resulting in a higher probability of failure and microfracture formation. Tight reservoirs containing more quartz and carbonate minerals were found to develop more microfractures. Quartz grains showed fractures at the margins under stress, which increased the pore permeability of rocks. Carbonate minerals tended to form microfractures owing to corrosion. Microfracture formation mechanisms differed depending on lithology, and microfractures were found to develop most in dolomite and dolomitic siltstones and least in mudstone. Muddy rocks developed fewer tectonic fractures because they can easily absorb stress and undergo plastic deformation. Within a certain stratum thickness range, the average single-well fracture space and stratum thickness showed positive correlations. Moreover, the fracture space increased and the fracture density decreased as the stratum thickness increased. When the stratum thickness was less than 2.5 m, the fracture space increased linearly with the stratum thickness, and when the stratum thickness was greater than 2.5 m, the fracture space remained constant. This study will provide an essential scientific basis for enhancing tight oil recovery.

1. Introduction

Natural fractures are widespread in tight reservoirs [1–4]. Microfractures affect not only the migration and accumulation of oil and gas but also the outcome of oil-gas development. However, existing research on microfractures is not comprehensive [5]. The formation, development, and connection of microfractures provide channels for the migration and

aggregation of oil and gas in tight reservoirs [6–9]. Microfractures are important spaces in tight reservoirs that gradually form large-scale and complex fracture networks [10–13]. Microfractures are defined as fractures with an opening of $<100\ \mu\text{m}$ and are unrecognisable on imaging logs or core samples but can be observed using microscopy (e.g., casting thin sections or scanning electron microscopy (SEM)); they are predominantly diagenetic or corroded fractures [14, 15].

Fractures with an opening between 100 nm and 1 mm are defined as microfractures, and fractures with a width of $<1\ \mu\text{m}$ are called supermicrofractures [16, 17]. The formation of microfractures is affected by tectonic movements, sedimentary environment, burying conditions, fluid properties, and other factors [18]. The genetic types of microfractures are defined by tectogenesis, which is related to diagenesis. When tectonic loading is applied externally, a rock can fracture and eventually fail along faults. Conversely, internal stresses may be related to increased fluid pressure inside the rock due to the dehydration of clays. The joints of microfractures can be analysed via the stress analysis of a rose diagram [19]. During diagenesis, sediments are affected by compacted shrinkage, mineral cementation, metasomatism, and recrystallisation. These occurrences induce the contraction and expansion of strata and the recombination and conversion of minerals. Such changes are accompanied by the development of microfractures to different degrees [20]. Microfracture formation is largely affected by early-stage compaction and late-stage corrosion. Corroded carbonate minerals can easily form corroded fractures, which normally develop along cleavages. Compacted rocks often develop compressed fractures [21–23]. The reservoirs in the Upper Palaeozoic Shihezi Formation were derived from diverse sources and contained various sediments, resulting in severe longitudinal lithological heterogeneity [21]. Diagenesis induces changes in lithological composition and significantly affects the physical properties of reservoirs. Diagenesis also differs considerably among strata, which can develop diverse and structurally complex pores. Microfractures are believed to be the main channels of reservoir seepage, and the distributive laws and developmental characteristics of microfractures are controlled by diagenesis and lithology [24].

Microfractures are detected and evaluated mainly using mercury intrusions, image analysis, imaging logs, and magnetic logs of core data. Considering that microfracture control mechanisms depend on the reservoir lithology, diagenesis, and pore type, a specific lithology can be recognised for any horizon. Thereafter, valid porosity and permeability evaluation models can be established based on lithology and horizon constraints. Wang and Rahman developed a microfracture evaluation model and an identification method to analyse more than 70 wells [25]. The relative error of permeability using logging evaluations was less than 10%, and many new active gas layers were observed [26]. Overall, among wells with a gas production rate exceeding the lower economic limit ($3 \times 10^4\ \text{m}^3/\text{d}$), more than 90% developed microfractures [27]. The wells with high single-well gas production rates developed high-permeability microfractures, thus validating the results of the model [24, 25].

The Lucaogou Formation in the Jimsar Sag of Junggar Basin in Xinjiang, China, is typical continental tight oil strata showing developed tight oil reservoirs with high-quality hydrocarbon source rocks, featuring active oil-gas exploitation, large oil-gas reserves, and significant exploration potential [7, 28, 29]. The Lucaogou Formation is one of China's most important tight oil strata. Since 2010, commercial oil production has been realised in several wells in the Jimsar Sag (including wells J23, J25, and

J30), representing a breakthrough in tight oil production in the southeast Junggar Basin [30, 31]. The Lucaogou Formation strata mainly comprise carbonate rocks, mudstone, and powder-fine sandstone [29]. Previous works in this region were mainly focused on the macroscale, such as the geological structure and sedimentary environment; however, little research has been conducted at the microscale. The role of fractures in reservoirs of Jimsar Sag has also been noted [31].

Hence, this study focused on qualitatively and quantitatively identifying microfractures in the Lucaogou Formation to clarify the causes and basic parameters of microfracture development. The developmental characteristics and control factors of the microfractures were elucidated, and the influence of microfracture development on reservoir properties was determined.

2. Geological Settings

The Junggar Basin is the second-largest basin in China. It is rich in tight oil reservoirs and shows high potential for exploration and development. It belongs to the Ural-Mongolia Orogenic Belt, which is surrounded by multiple orogenic belts, such as the Altai and Bogda Mountains. Its north is bounded by the Shaqi Uplift and Jimsar Sag, and its south is bounded by the Houbaozi Fault. Its west is bounded by the Xidi Fault and Beisantai Uplift, and its east transitions from a slope to the Guxi Uplift (Figures 1 and 2). The Junggar Basin is surrounded by several other basins such as Tuha, Erie, and Santanghu Basins [32–35]. The Junggar Basin initially formed during the Hercynian activity period. In the late Early Permian, the Bogda Trough at the south margin of the basin was closing for orogenesis. In the late Middle Permian, the Lucaogou Formation started experiencing lacustrine facies sedimentation, forming the main hydrocarbon source rocks in this region. In the Late Triassic, the Indo-China Movement occurred, leading to severe uplifting of the Guxi Uplift and the Permian differential corrosion. During the Yanshan Movement, frequent and severe tectonic movements occurred inside the Junggar Basin, inducing gentle uplift in the southeast. The Himalayan Movement formed from the Neogene to Quaternary, leading to the rest of the basin evolution [32, 34, 36, 37].

The internal tectogenesis of Jimsar Sag is relatively stable, and the inner strata of the basin are complete, with maximum sedimentation thickness of 5000 m. The stratigraphic framework of Jimsar was formed after the Himalayan orogeny. The strata are mostly in conformable contact, and the deficient part comprises the Huangshanjie Formation, Jurassic Kelazha Formation, and Triassic Haojiagou Formation. The Lucaogou Formation (P2l) originates from the Permian and is beneath the Wutonggou Formation (P3wt) and above the Jiangjunmiao Formation (P2j). Full-well cores were collected from well J174 in the basin. Based on its lithology, magnetic logs, electric data, and systematic analysis, the Lucaogou Formation can be divided into two segments (P2l2 and P2l1) and four layers (P2l21, P2l22, P2l11, and P2l12) [38].

FIGURE 1: Structural division of the Junggar Basin.

The Lucaogou Formation was affected by mechanical sedimentation, thus comprising hybrid sedimentary rocks deposited in salty lakes. During the Penecontemporary period, rocks in this area experienced severe dolomitisation; hence, dolomites normally developed with micrite and microcrystalline structures, with small grain-sized detritus enriched with carbonate rocks, mudstone, and powder-fine sandstones that were mostly interlayered. The rock types

mainly include mudstone, fine siltstone, and carbonate rocks. The fine siltstone mainly includes dololithite fine siltstone, lithic feldspar fine siltstone, and dolomitic fine siltstone. The carbonate rocks mainly include muddy microlite dolomite, fine sandy dolomite, and sand detritus dolomite. The carbonate rocks are dominated by dolomitic rocks and limestone, which comprise up to 74.15% in some areas. Thus, the Lucaogou Formation is generally rich in carbonate minerals

FIGURE 2: Typical microfractures with a high opening in casting thin section of the Lucaogou Formation in the Jimsar Sag: (a) well J251, 3741.77-3742.27 m; (b) well J251, 3769.01-3769.39 m.

and is highly brittle, making it suitable for large-scale exploitation [39]. The Lucaogou Formation is well developed with microfractures. The tight sandstone in the study area is rich in clay but has fewer authigenic minerals than the crystals of common sandstone reservoirs. In addition to autogenetic causes (including the cause of alteration), terrigenous detritus sedimentation is observed.

3. Methodology

72 rock samples were collected from 22 exploration wells in the Middle Permian of the Lucaogou Formation. These samples included grey dolerite, feldspathic, dolomitic lithic sandstone, and dolomitic mudstone. Before the tests, the core samples were washed with a mixture of trichloromethane and alcohol to eliminate residual oil and then dried at 115°C for 26 h under vacuum. Each core sample was drilled to a size with a diameter and length of 2.54 and 5.00 cm, respectively. The following methods were adopted for investigations: casting thin sections, SEM, acoustic emission (AE), and nuclear magnetic resonance (NMR). Casting thin sections and SEM can clearly visualise the morphology, occurrence, filling, and peripheral mineral contact of microfracture development. AE and NMR can clarify the structural characteristics of rocks.

3.1. Microscopy. The casting thin section and scanning electron microscopy experiments were completed in the State Key Laboratory of Petroleum Resources and Exploration, China University of Petroleum (Beijing). The samples were detected by ZEISS Merlin and GeminiSEM instruments. Casting thin sections were used to study the quantity, type, and distribution of pores. A staining resin or liquid glue was perfused into the rock pores under vacuum. The resin or glue solidified at a certain temperature and pressure, and the rock was then ground into sections, which were used to observe pore structures under polarisation [40]. Figure 2(a) shows a cast thin section with two microfractures with an opening of 2–5 μm . The microfractures exhibit an oblique crossing strike with bedding; hence, they appear to be tectonic fractures that mainly formed because of external forces.

Figure 2(b) shows a cast thin section with only one microfracture with an opening of 1–3 μm that developed along the layers. Thus, it appears to be a bedding fracture. SEM is a comprehensive analyser that affords high-resolution images and can be used to observe microfractures up to several nanometres [41, 42]. More than 200 SEM images and cast thin sections were acquired from 10 wells in the study area, including J174, J251, J36, and J172. Secondary microfractures were mainly observed, with only a few original intergranular pores, and they mostly developed along the layers. Figure 3 shows that the fractures developed inside minerals or along mineral margins with complex arrangements.

3.2. Acoustic Emissions. The rock triaxial acoustic emission experiment was completed in the Laboratory of Rock Mechanics, China University of Petroleum (Beijing). The test loading was carried out by the MTS 815 rock mechanics test system of MTS Company, and the acoustic emission acquisition was carried out by the PCI-II acoustic emission monitoring system of PAC Company. The AE technique visualises the changes in internal materials in rocks using AE events. AE events record the AE induced in the rocks owing to changes resulting from external forces. An AE experiment was performed, and the variations in the energy count and AE count were used to analyse the fracture process. The fracture process occurs in three stages. In the crack concentration stage, the initial microfractures gradually grow under external forces; thus, the AE curve manifests as a smooth rising line. In the fracture expansion stage, the expansion is intermittent; hence, numerous fractures are formed, showing a zigzag curve. In the broken damage stage, the rocks suddenly experience instantaneous failure [43, 44]. Research on the Yanchang Formation in the Ordos Basin showed that microfractures are formed when the external force imposed on a rock reaches the fracturing intensity. Hence, AE events can be measured using an AE curve to indicate the exact location of microfractures [45–47]. The experiments verified that after passing Caesar's phenomenon, the first small-scale microrupture period is the microfracture formation period. As shown in Figure 4, the cumulative number of AE events

FIGURE 3: Typical microfractures are developed inside minerals or along mineral margins in microscopic scale of the Lucaogou Formation in the Jimsar Sag: (a) well J251, 3751.44 m; (b) well J251, 3565.5 m.

FIGURE 4: The acoustic emission curve of the three-axis compression process: (a) curve of acoustic emission count with time; (b) curve of energy count with time.

FIGURE 5: NMR T_2 features (saturated curve, centrifugation, cumulative curve after saturation, and cumulative curve after centrifugation) of samples from well 174.

on the AE curve was used to determine the number of microfractures [48].

3.3. Nuclear Magnetic Resonance. The NMR T_2 distributions were measured at 20°C using a 2 MHz Suzhou Niumag Analytical Instrument at State Key Laboratory of Petroleum Resources and Prospecting. The rock samples were subjected to NMR tests. The area of the NMR T_2 spectrum indicates the variation in the pore structure and is proportional to the pore fluid concentration in rocks. Herein, the relaxation time was used to observe the pore size distributions of rock samples. When the relaxation time is long, the corresponding T_2 spectrum indicates the pore volume of relatively large-sized pores. The microfractures of tight sandstone can be studied via the qualitative and quantitative analyses of NMR data [49]. Figure 5 shows that a new peak appeared in the T_2 spectra under the saturated status, and the original peak moved leftwards to form a double peak. These results indicate the formation of numerous microfractures that contributed to the porosity of the rock samples. When the NMR T_2 spectra were observed in the irreducible water state, the right-side peak disappeared. Considering that fractures easily broke in the centrifugal status, the right-side peak can be considered to indicate microfracture formation. The fracture/microfracture percentage ratio can be defined as the sum of T_2 spectral amplitudes with a relaxation time T_2 of >10 ms divided by the total number of T_2 spectral amplitudes [50, 51]. Because microfractures can easily break during centrifugation and NMR analysis, the fracture/microfracture percentage ratio was used to represent the development degree of microfractures in each sample.

3.4. Experimental Procedure. First, porosity experiments based on helium were performed to select samples with consistent lithology and relatively large porosity. The sam-

FIGURE 6: Experimental flowsheet on fluid saturation correlation between microfractures and pores.

FIGURE 7: Three-dimensional stress diagram.

ples were saturated to 100% using a saturation metre and then saturated to different degrees by reconfiguration in centrifugation experiments. Then, the samples were sealed. Finally, triaxial compression experiments were performed, and AE was used to monitor fracture formation. Figure 6 shows the relationship between fractures and the pore fluid concentration.

Centrifuging is widely used to separate standard rock samples into high, medium, and low permeability. The centrifugal pressure must satisfy

$$P = 1.097 \times 9L \left(R_e - \frac{L}{2} \right) n^2, \quad (1)$$

where L is the rock length (mm), R_e is the epitrochoid radius (mm), and n is the rotating speed at the head of the centrifuge.

Triaxial compression experiments were performed, where the three-dimensional stress states of rock samples were simulated (Figure 7) to measure the maximum and minimum principal stresses. Then, the compressive strength, internal friction angle, and cohesion of the rocks were measured using multiple tests.

Three groups of rocks were placed in a saturation metre. Because all rock samples were tight sandstone, the static pressure for saturation was set to 20 MPa. Four rock samples (two samples per group) were placed in an LD5-10B centrifuge and centrifuged at 8000 rotations. After 1 h, the rock samples were removed. Then, one sample from each group was selected and placed inside the centrifuge again. When the lithology is consistent and the centrifugation time is the

TABLE 1: Parameters involved in the acoustic emission counting for the Lucaogou Formation tight sandstones in the Jimsar Sag, Junggar Basin.

Group	No. of core	Condition of water saturation (%)	Acoustic emission counting
G1	J174-1	0	50
	J174-2	30	65
	J174-3	80	100
	J174-4	100	166
G2	J22-1	0	53
	J22-2	30	74
	J22-3	90	101
	J22-4	100	169
G3	J36-1	0	56
	J36-2	30	65
	J36-3	70	107
	J36-4	100	170

same, the rock samples must show a consistent decrease in water content. The above steps were repeated successively. The centrifuged samples were then immediately sealed for the triaxial experiment. The rock samples were set in an anti-oil and antipressure plastic set that was custom-made and softened using blowing so that the samples tightly clung to the set. The set was installed according to experimental requirements. Then, the sensor was adjusted and slowly compressed. Simultaneously, the AE analyser was started. Thereafter, the corresponding rock mechanical parameters were determined. The AE curves were used to record the number of AE rings upon microfracture formation (i.e., number of AE events) (Table 1).

The main factors that affect the formation of microfractures in rocks are the contents of fragile minerals and carbonates. In this experiment, the quantitative relationship between microfractures and mineral composition was mainly studied from two aspects. First, several rock samples rich in carbonates were selected according to their lithological data and physical properties. Then, the rocks were fractured in triaxial compression experiments to form microfractures. Samples showing evident microfractures in the NMR T_2 spectrum were selected and used to analyse the quantitative relationship between the mineral composition and microfractures (Figure 8).

The main form of NMR applied to tight sandstone is usually the transverse relaxation time T_2 . Under rapid diffusion conditions, the relaxation time T_{2a} of a pore fluid can be approximated as

$$\frac{1}{T_{2a}} = \frac{1}{T_{2b}} + \rho_2 \frac{S}{V}, \quad (2)$$

where T_{2b} is the inherent relaxation time (ms) of pore fluid in a rock, ρ_2 is the surface relaxation rate in a fluid-containing pore ($\mu\text{m/ms}$), and S/V is the ratio of surface area to volume

FIGURE 8: The experimental flow chart of correlation between microfractures and mineral composition.

of the corresponding pore and is inversely proportional to the pore size:

$$\frac{S}{V} = \frac{F_s}{r}, \quad (3)$$

where F_s is the pore shape factor and r is the pore radius. When the pore fluid is water or light oil, the long inherent relaxation time leads to

$$\frac{1}{T_{2a}} = \rho_2 \frac{S}{V}. \quad (4)$$

For the same rock sample, the relaxation rate ρ_2 and pore shape factor F_s can be approximated as constants. Hence, the T_2 spectra can be used to determine the distribution of rock pores because rocks with longer relaxation times correspond to larger fractures, and vice versa [52, 53].

Before the experiments, tight sandstone samples were ground and paralleled. The samples were dried in a thermostatic drying chamber at 60°C for approximately 24 h until the weight no longer changed. Then, the basic parameters of the samples were measured at a peripheral pressure of 900 psi, air pressure of 400 psi, and pulse attenuation of PDP-200. To further clarify the mineral composition, the rock samples were tested in terms of the total organic carbon, kerogen ultimate analysis, whole-rock mineral X-ray diffraction, and organic matter macerals.

4. Genetic Types of Microfractures

Microfracture formation was primarily attributed to the tectonic stress field during rock diagenesis [54, 55]. Given the small openings and invisibility of microfractures, microscopy (i.e., casting thin sections and SEM) was used to observe their developmental characteristics to explore genetic types. Microfractures were generally well developed in the Lucaogou Formation with complex genetic types, including tectonic fractures, bedding fractures, intragranular fractures, marginal fractures, corroded fractures, diagenetic contraction fractures, and organic hydrocarbon-producing high-pressure fractures. These microfractures can be broadly classified as tectonic (i.e., directional), granular, or diagenetic based on their genetic types.

FIGURE 9: Tectonic-breaking microfractures in microscopic scale of the Lucaogou Formation in the Jimsar Sag: (a) well J31, 2715.94 m; (b) well J31, 3769.33 m.

FIGURE 10: Bedding fractures in microscopic scale of the Lucaogou Formation in the Jimsar Sag: (a) well J251, 3769.01 m; (b) well J251, 3769.01 m.

4.1. Tectonic Microfractures. Small-scale high-elongation tectonic fractures are formed, and some even cut through rocks and grains. They can connect with other fractures and even form networks to improve seepage [10, 11]. Tectonic fractures cut through beddings and are straight and even with openings of $0.01\text{--}10\text{ }\mu\text{m}$ (Figure 2). Most tectonic microfractures are filled with quartz, calcite, and dolomite and rarely with mud (Figure 2). Such tectonic fractures are formed when minerals are destroyed under stress that exceeds their fracture strength [14, 15]. Their developing planes are straight, even, and open to varying degrees. Tectonic fractures are commonly seen in quartz, feldspar, and other fragile minerals but rarely in clay minerals (Figure 9).

Bedding fractures are related to tectogenesis. Because beddings are the weak surfaces of strata, when the pressure gradient inside a closed system is greater than a critical value, a part of the bedding surface dislocates or opens to form a

fracture [52, 56]. Bedding fractures are nearly parallel to the bedding surface and cross mineral grains. They are typically manifested as one broad head and one gradually sharpening head. Bedding fractures are $0.1\text{--}5\text{ }\mu\text{m}$ wide and $0.1\text{--}10\text{ mm}$ long; they are mostly filled with mud, iron or quartz, feldspar, calcite, and other minerals in the later stage, with a filling degree of 80% (Figure 10).

4.2. Diagenetic Microfractures. Diagenetic microfractures result from diagenesis and show no definite orientation. They are open to varying degrees. Diagenetic microfractures exhibit irregular shapes, distributions, and sizes and are mostly branch- or cobweb-like. Common types include diagenetic contraction fractures, organic hydrocarbon-producing fractures, and corroded fractures. Diagenesis contraction fractures are found in kaolinite and other clay minerals, which contract upon dehydration because of their

FIGURE 11: Diagenetic contraction fractures in microscopic scale of the Lucaogou Formation in the Jimsar Sag: (a) well J251, 3751.44 m; (b) well J251, 3565.5 m.

FIGURE 12: High-pressure microfractures in microscopic scale of the Lucaogou Formation in the Jimsar sag: (a) well J251, 3751.44 m; (b) well J251, 3751.44 m.

FIGURE 13: Dissolution fractures in microscopic scale of the Lucaogou Formation in the Jimsar sag: (a) well J31, 2751.94 m; (b) well J251, 3784.11 m.

FIGURE 14: Gravel-edge fractures and corrosion fractures in microscopic scale of the Lucaogou Formation in the Jimsar Sag: (a) well J251, 3408.75 m; (b) well J251, 3408.75 m.

scale-like crystals to form fractures nearly parallel to the mineral layers [57]. High silicon reservoirs form diagenetic contraction fractures because of dehydration, mineral phase transformation, or thermodynamic contraction. Diagenetic contraction fractures are commonly seen in stratified minerals and exhibit diverse shapes, including straight or curved. They do not extend considerably but are well connected with large openings (Figure 11).

Organic hydrocarbon-producing high-pressure fractures are intragranular porous fractures that form when organic-rich argillaceous interlayers in tight reservoirs are sufficiently mature and buried sufficiently deep (Figure 12). This is probably because porous fractures are formed because of organic depletion after hydrocarbon generation from kerogen, water consumption owing to hydrocarbon generation, or increased pressure owing to hydrocarbon formation. Moreover, organic matter and adjacent minerals can form porous fractures owing to hydrocarbon formation, likely attributed to

FIGURE 15: Classification diagram of genetic types of microfractures.

FIGURE 16: Comparison between the NMR experiment and the acoustic emission experiment of well J174 based on a variable saturation: (a) NMR experiment of well J74 with 30% water saturation; (b) NMR experiment of well J74 with 80% water saturation; (c) AE experiment of well J74 with 30% water saturation; (d) AE experiment of well J74 with 80% water saturation.

organic matter contraction or pressure increment after hydrocarbon production.

Corroded fractures are formed when organic acids or underground fluids generated from hydrocarbon formation corrode the rock [14, 16, 17, 58–60]. The organic acids formed from the thermal evolution of organic matter provide H^+ and metallic elements for complexation, improving the solubility of minerals and affecting their stability. This leads to intragranular or intergranular corrosion. The degree of corrosion is related to the mineral type because different minerals exhibit differing levels of corrosion resistance. Calcite, dolomite, and other carbonates are the most easily corroded, followed by quartz and feldspar. Clay minerals show the highest corrosion resistance (Figure 13).

4.3. Granular Microfractures. Granular microfractures are formed along some fractured grains or particulate joints because of external forces and are mainly related to corrosion [61]. Granular microfractures mainly include intragranular and marginal fractures. Early-stage fractures are filled in the later stages and are less significant; however, once the filling corrodes, the fractures become more connected and significant [62–64]. SEM analysis revealed the intergranular fractures that formed more easily among different minerals but

not within the same mineral type (Figure 14). Owing to different crystal lattices among different minerals, they grow in different directions and thus can easily form intergranular fractures. Within the same mineral type, the formation of intergranular fractures is rare owing to consistent crystal lattice directions. Moreover, the mechanical properties differ among minerals; hence, they deform differently when subjected to the same stress, which also encourages intergranular fractures.

Generally, the Lucaogou Formation mainly developed diagenetic microfractures followed by tectonic microfractures, with little formation of granular microfractures (Figure 15). Statistical analysis of the cast sections showed that tectonic microfractures (directional microfractures) mostly developed near well J174. This indicates that besides the large-scale basin-wide geological activities, small-scale geological activities very likely occurred at this well. Diagenetic microfractures were mainly near well J34, indicating that this site is rich in organic matter and fragile minerals.

5. Results and Discussion

5.1. Relationship between Microfractures and Pore Fluid. The relationship between fractures and the pore fluid was

TABLE 2: Effect of fluids on mechanical properties of the Lucaogou Formation tight sandstones in the Jimsar Sag, Junggar Basin.

Water saturation (%)	Compressive strength (GPa)	Ratio of decrease (%)	Elastic modulus (GPa)	Ratio of decrease (%)	Poisson's ratio	Ratio of increase (%)	Group
0	156.94		29.75		0.259		G1
30	151.44	0.035	22.78	0.23	0.258	0.0039	G1
80	146.12	0.035	20.23	0.11	0.295	0.1434	G1
100	80.58	0.449	7.52	0.63	0.554	0.8780	G1
0	156.33		25.01		0.283		G2
30	146.16	0.065	21.65	0.13	0.284	0.0035	G2
90	90.22	0.321	14.30	0.34	0.289	0.0176	G2
100	80.23	0.191	8.30	0.42	0.446	0.5433	G2
0	146.21		26.35		0.214		G3
30	140.90	0.036	20.99	0.20	0.221	0.0327	G3
70	93.73	0.335	18.88	0.10	0.368	0.6652	G3
100	79.26	0.154	15.36	0.19	0.392	0.0652	G3

TABLE 3: Test data of core sample from well J34.

Sample	Nonbrittle mineral content (%)				Brittle mineral content (%)				
	Clay mineral	Chlorite	Illite	Mixed-layer illite	Quartz	Calcite	Dolomite	Feldspar	Pyrite
J37-1	44	24	59	16	43	1	2	6	4
J37-2	24	10	71	19	63	4	6	1	2
J37-3	28	11	70	19	48	7	4	12	1
J37-4	25	14	55	31	43	8	8	13	3

evaluated in terms of lithomechanical properties. The NMR T_2 spectrum of well J174 revealed additional microfractures and micropores as the water saturation increased. The same results were obtained from the AE experiments. In Figure 16, the curve of the AE count under the purple line indicates the number of microfractures, and that above the purple line indicates fractures. The AE ring count significantly increased as the water saturation increased, indicating the formation of additional microfractures.

The results of the triaxial experiments showed that the deformation parameters of rocks followed different trends depending on the degree of saturation. As the water content increased, the compressive strength and elastic modulus decreased by 45%–65% compared with the dry condition. Moreover, Poisson's ratio increased by 80% compared with the dry condition. These results indicate that the presence of a pore fluid affects the mechanical properties of rocks (Table 2).

As the pore fluid content increased, the compressive strength and elastic modulus decreased more rapidly, Poisson's ratio increased faster, and pore fluids more severely affected the mechanical properties of rocks. Contrarily, as the pore fluid content decreased, the compressive strength and elastic modulus decreased more slowly, Poisson's ratio increased more slowly, and pore fluids less severely affected the mechanical properties of rocks. The AE experiments showed that the AE ring count was proportional to the number of microfractures and significantly increased with increasing pore fluid content, indicating the formation of

additional microfractures. Furthermore, the number of microfractures showed a positive correlation with the pore fluid content.

The pore fluid content affected not only the deformation parameters but also the deformation and failure mechanisms of the rocks. The presence of pore fluid changed the rock strength and deformation because it can relieve the intergranular cohesive strength of rocks and accelerate the molecular motion of fluids. The liquid and gas filling the microfractures generate pore pressure, which partially offsets the total stress imposed on a random section on rocks, including peripheral pressure and tectonic stress. Such pressure decreases the elastic yield strength of rocks and makes them more susceptible to deformation, further affecting the formation and development of internal microfractures in the rocks. The presence of pore fluid also decreases the shear strength of rocks and makes them more susceptible to shear deformation. In summary, the pore fluid content mainly affects the mechanical properties of rocks and controls the developing degree of tectonic fractures. However, changes in the lithomechanical properties have little effect on the development of bedding fractures.

5.2. Relationship between Microfractures and Mineral Composition. Ten rock samples were selected and found to be rich in carbonate and fragile minerals (Table 3). After the samples were sealed, triaxial experiments were conducted. The rocks were compressed and saturated with water at certain degrees of mineralisation. The rock samples were

TABLE 4: NMR test results of samples from well J34.

Sample	Length (cm)	Diameter (cm)	Nuclear magnetic analysis		
			Fracture/microfracture content (%)	Water saturation (%)	200 psi
J37-1	5.082	2.539	17.33	100	52.15
J37-2	5.051	2.539	3.71	100	84.33
J37-3	5.086	2.531	9.61	100	86.58
J37-4	5.071	2.539	12.72	100	67.12

FIGURE 17: T_2 features of samples: (a) NMR of type I fractures; (b) NMR of type II fractures; (c) NMR of type III fractures.

displaced with oil and salts. According to laboratory standards, NMR was then applied to the saturated water cores. The NMR T_2 spectra were used to select rocks according to their microfracture characteristics (Figure 5) and calculate the corresponding fracture/microfracture ratio (Table 4).

The Lucaogou Formation mainly consists of five facies: sand detritus dolomite, micrite dolomite, dolomitic fine siltstone, argillaceous fine siltstone, and mudstone. The first

member of Lucaogou (Lu1) mainly shows three types of sedimentation: graded in situ mixed sedimentation, combined marginal mixed sedimentation, and graded parent-derived mixed sedimentation. The second member of Lucaogou (Lu2) mainly exhibits three types of sedimentation: mutant in situ mixed sedimentation, graded in situ mixed sedimentation, and combined marginal mixed sedimentation. The mechanical properties of the reservoir rocks were mainly

FIGURE 18: T_2 features of samples: (a) relationship between quartz content and microfractures; (b) relationship between carbonate content and microfractures.

affected by two components: (1) brittle components, such as calcareous and siliceous components, and (2) plastic components, such as argillaceous components [65].

The NMR images after triaxial compression experiments showed that the compressed fractures were mainly distributed as three types. Type I showed only one peak (P_1), and the fractures were distributed in areas with a short relaxation time ($T_2 < 10$ ms), indicating that only tiny pores were formed (Figure 17(a)). Type II exhibited two peaks (P_1 and P_2) distributed in areas with relatively long and short relaxation times, respectively, suggesting the development of tiny pores and microfractures (Figure 17(b)). Type III exhibited three peaks ($P_1 - P_3$) with long relaxation times, suggesting the formation of macrofractures (Figure 17(c)). This type of fracture is difficult to observe using NMR. The presence of macrofractures increased the breakability of the rocks in the centrifugation experiments.

In tight sandstone, a higher quartz content was positively correlated with a larger fracture/microfracture ratio (Figure 18(a)). Moreover, a higher carbonate content was positively correlated with a larger fracture/microfracture ratio (Figure 18(b)). Quartz is mainly composed of SiO_2 . According to the rock rupture mechanism, when quartz grains are stressed, their margins easily form marginal frac-

tures, which increase the pore permeability. Rocks containing a high silicon content are more brittle and can more easily form fractures. Furthermore, carbonate minerals are more prone to corrosion, forming corroded microfractures. Rocks with more carbonates can form microfractures more easily.

5.3. Relationship between Microfractures and Lithology. Sections from 10 wells in the study area were sent for granularity analysis. Combined with the lithological data, the sandstone in the study area was found to be generally fine-grained and well separated. Fine-sand and medium-sand rocks accounted for 60% and 23%, respectively. Microfractures also developed in dolomite, dolomitic mudstone, mudstone, and dolomitic fine siltstone. The types and characteristics of microfractures differed depending on lithology. Mudstone was mainly black or grey black and contained few macrofractures. It mainly developed with organic hydrocarbon-producing high-pressure fractures and corroded fractures. The dolomitic mudstone was greyish white and mainly developed with bedding fractures. The dolomitic siltstone was greyish white and mainly developed with bedding fractures and tectonic fractures.

The casting thin sections and 200 SEM images from nearly 20 wells in the Lucaogou Formation were classified

(a)

(b)

(c)

(d)

(e)

(f)

FIGURE 19: Continued.

FIGURE 19: The correlation diagram of microfractures and lithology: (a) microfracture surface density of sandy dolomite; (b) microfracture frequency of sandy dolomite; (c) microfracture surface density of micritic dolomite; (d) microfracture frequency of micritic dolomite; (e) microfracture surface density of dolomitic fine sandstone; (f) microfracture frequency of dolomitic fine sandstone; (g) microfracture surface density of argillaceous siltstone; (h) microfracture frequency of argillaceous siltstone; (i) microfracture surface density of mudstone; (j) microfracture frequency of mudstone.

according to lithology, and the microfractures were statistically analysed (Figure 19). The microfractures clearly developed according to the lithology. Generally, dolomite showed the highest microfracture density, followed by dolomitic siltstone, dolomitic mudstone, and mudstone. Hence, the microfracture development was observed to be closely related to lithology.

5.4. Relationship between the Fracture Space and Stratum Thickness. The Lucaogou Formation is enriched with hydrocarbon source rocks and has two major sweet points. The upper sweet point is divided into four sublayers: STD-1, STD-2, STD-3, and STD-4. The lower sweet point is segregated into six sublayers: XTD-1, XTD-2, XTD-3, XTD-4, XTD-5, and XTD-6. Statistical results showed that when the rock mechanical parameters and stress conditions were the same, thin rock layers were more likely to form high-density microfractures than thick rock layers. Because dolomite is rich in carbonate minerals, the microfractures formed from its corrosion affected the results. Hence, the microfrac-

tures in sections collected from sandstone layers of the study area were statistically analysed. The sections from the upper and lower sweet points of the Lucaogou Formation were statistically analysed under microscopy. Up to a stratum thickness of 2.5 m, the average single-well fracture space increased with the stratum thickness and the fracture density decreased. When the stratum thickness was greater than 2.5 m, the fracture space remained constant. Lithomechanical experiments verified that when the same stress ratio was applied for a certain time, the fracture space increased with the stratum thickness.

6. Conclusions

- (1) The Lucaogou Formation mainly developed diagenetic microfractures followed by tectonic microfractures, with little development of granular microfractures. The developing degree of the microfractures showed correlations with the pore

fluid content, mineral composition, lithology, and stratum thickness

- (2) The count of AE events showed a positive correlation with the microfracture density. A higher pore fluid content indicated a lower compressive strength of the rocks and a higher likelihood of microfracture formation
- (3) NMR obtained the fracture/microfracture percentage ratio. A higher fracture/microfracture percentage ratio indicated a higher content of fragile minerals in the rock and thus a higher likelihood of microfracture development
- (4) Thin rock layers were more likely to form high-density microfractures than thick rock layers when the rock mechanical parameters and stress conditions were the same

Data Availability

The main data used to support the study is available within the article. Readers interested in the data can communicate with the corresponding authors and obtain this data by email.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

Authors' Contributions

Xiangye Kong and Haowei Yuan contributed equally to this work.

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