Research Article

Micro- and Nanoscale Pore Structure Characterization of Carbonates from the Xiaoerbulake Formation in the Tarim Basin, Northwest China

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Received 30 October 2020; Revised 23 November 2020; Accepted 12 April 2021; Published 29 April 2021

1. Introduction

Carbonate reservoirs have a considerable exploration and exploitation significance as they contain a significant proportion of the world’s hydrocarbon resources [1]. China has a vast area of carbonate rock, mostly located in the Tarim and Sichuan Basins. Cambrian-aged carbonates are widely developed in the Tarim Basin with a thickness of over 2100 m covering an area of 41 × 104 km², and they form part of well-developed source-reservoir-seal petroleum system. Since commercial hydrocarbon production started in 2013 from the Xiaoerbulake Formation in Well ZS 1 drilled in the central uplift of the Tarim Basin [2], Cambrian carbonates have become an exploration target in the Tarim Basin. However, for the experiences of more than 100 million years of geological history, also multistage tectonic movements and diagenetic transformations, a pattern of multiple media was formed in Cambrian carbonate reservoirs, which cause the extremely high heterogeneity [3].

Previous studies of Cambrian carbonates in the Xiaoerbulake Formation have mostly focused on the provenance of the carbonates, their sedimentary characteristics, and pore formation [4]. For example, Li et al. [5] studied the origin and development of porosity. Bai et al. [6] investigated the
geological characteristics and major controlling factors of platform margin microbial reef reservoirs in the formation. However, less attention has been paid to the pore structure (both geometry and connectivity [7] of the carbonates), which is an essential part of reservoir characterization including reservoir quality, hydrocarbon storage capabilities and transport properties.

The pore structure in carbonates is more complex and heterogeneous, compared with conventional reservoirs such as sandstones, due to the diverse pore types caused by sedimentation and diagenesis [8–10]. Recent studies indicate that the Xiaoerbulake Formation is characterized by low porosity, low permeability, and strong heterogeneity [6, 11]. As a result, a number of complementary methods are needed to evaluate and characterize the structure and connectivity of pore networks at the microscale in these carbonate reservoirs.

In recent years, fractal theory has been widely used to describe the irregularity and roughness of natural structures [12]. Pfeifer et al. [13] suggested that the microstructure of rock pores is fractal. Krohn [14] proposed that in a certain pore size range, carbonate rocks, sandstone, and shale show typical fractal characteristics, while Muller [15] first characterized the multifractal behavior of pore spaces in sedimentary rocks. And according to Xie et al. [16], the pore structure of carbonates is multifractal using the box-counting method applied to images from environmental scanning electron microscopy (ESEM). Therefore, the pore heterogeneity of carbonate rocks can be defined by fractal dimensions [16], and as a result, the heterogeneity of pore structures was quantitatively assessed in a single parameter.

The purpose of this research is to qualitatively and quantitatively characterize the micro- and nanoscale pore structure of carbonate reservoir carbonates from the Xiaoerbulake Formation in the Tarim Basin, Northwest China, classify the pore network types of carbonate in the study area, and investigate the connectivity for various pore network types. In this study, the pore structure of outcrop carbonate samples from the Xiaoerbulake Formation was observed directly in photomicrographs (optical microscopy and field emission-SEM), the porosity was measured by different methods including vacuum saturation and routine core analysis, and the pore-throat size distributions were obtained by mercury intrusion porosimetry (MIP). Subsequently, the micro- and nanoscale pore network was classified into three types based on the analysis of MIP data and curves. The fractal dimensions of different pore networks were derived from the MIP results. Moreover, the connectivity of pore networks was evaluated by spontaneous imbibition and the relationships between pore structure (pore-throat diameter and tortuosity) and connectivity have been investigated.

2. Geological Setting

The Tarim Basin is located in northwest part of China, covering an area of about 560,000 km², and is the largest basin with hydrocarbon production in China. Keping uplift is located in the northwest margin of the Tarim Basin, Wushi County, Akesu Prefecture, with an area of nearly 20,000 km² (Figure 1). Keping uplift is a thrust belt formed by thrust nap-
characterized by the MIP technique. Samples were prepared as 1 cm³ cubes, and for removing the moisture in connected pore spaces, cubic samples were drying in a 60°C oven for more than 48 hours, then left to cool at room temperature. The MIP analyses were carried out using the Micromeritics AutoPore 9520. Mercury which has the molecular size of 0.31 nm is nonwetting to most porous materials and has high interfacial tension with air. When the intrusion pressure is increasing, mercury is pressed into the connected pore networks, and the pore radius can be calculated from the Washburn equation [25]:

\[ P_c = \frac{2 \times \sigma \times \cos \theta}{r}, \]  \( (1) \)

where \( P_c \) is the mercury intrusion capillary pressure, \( r \) is pore radius, \( \sigma \) is the interfacial tension between mercury and air, and \( \theta \) is the contact angle through the mercury phase. In this study, the pressure range used was from 5 psi (0.034 MPa) to 60000 psi (413 MPa), connected pore spaces with pore-throat diameters ranging from 2.8 nm to 50 μm could be measured, and the published physical constant values used were surface tension = 485 mN/m and contact angle = 140° [26].

The permeability of a connected pore network can be derived from MIP data using the method of Thompson [26] and Katz [27]:

\[ K = \frac{1}{89} \frac{L^3_{\text{max}}}{L_i} \phi S_{r_{\text{max}}}, \]  \( (2) \)

Figure 1: Location of study area and sampling sections.
in which $k$ (μD) is absolute permeability, $L_{\text{max}}$ (μm) is the pore-throat diameter at which hydraulic conductance is maximum, $L_t$ (μm) is the characteristic length representing the pore-throat diameter corresponding to the critical pressure $P_t$ (psia), ϕ is porosity, and $S_{\text{max}}$ represents the fraction of connected pore space composed of pore diameter of size $L_{\text{max}}$ and larger.

From MIP data, an important topological parameter, effective tortuosity $\tau$, can also be derived via Equation (3) [28, 29]:

$$\tau = \sqrt{\frac{\rho}{24k(1 + \rho V_{\text{tot}})}} \int_{\eta = r_{\text{min}}}^{\eta = r_{\text{max}}} \eta^2 f(\eta) d\eta,$$

(3)

where $\rho$ is mercury density (g/cm$^3$), $V_{\text{tot}}$ is total pore volume (mL/g), $k$ is permeability (Darcy), and $\int_{\eta = r_{\text{min}}}^{\eta = r_{\text{max}}} \eta^2 f(\eta) d\eta$ is the pore throat volume probability density function [7].

Equation (4) relates the effective tortuosity $\tau$ to the effective diffusion coefficient and travel distance of mercury molecules [30–32]:

$$\tau = \frac{D_0}{D_f} \left( \frac{1}{\phi} \right) \left( \frac{L_t}{L} \right)^{1/2},$$

(4)

with $L_t/L$ is defined as the geometrical tortuosity[7].

Previous studies have confirmed that the pore structure complexity, which indicates the heterogeneity condition of the pore structure (e.g., pore-throat diameter, pore shape, and pore size distribution), can be quantitatively analyzed by fractal dimensions [1, 14, 33]. Several models have been used to derive fractal dimensions from MIP data, such as the tubular model, spherical model [34, 35], and the thermodynamic model reported by Zhang and Li [36]. In this work, the tubular model derived from MIP data was adopted to obtain the fractal dimensions of carbonate samples, because of negative results occurred by using the spherical model which are irrational.

Based on the fractal geometry theory, if pore structure is fractal, it will satisfy a specific power-law function [12]:

$$N(>r) \propto r^{-D_f},$$

(5)

where $r$ is the pores radius (or characteristic length), $N(>r)$ is the number of pore with radius larger than $r$, and $D_f$ is the fractal dimension.

When assuming a tubular model, pore networks of samples are a bundle of tortuous capillary tubes [37]. According to Li [38], the number of units required to fill the entire
Table 1: Pore structure properties from routine core and MIP tests.

| Sample no. | Median pore-throat diameter (nm) | Volume \(4V/A\) | Average pore-throat diameter (nm) | Effective tortuosity \(D_0/D_e\) | Geometrical tortuosity \(L_e/L_{geo}\) | Porosity* (%) | Porosity\# (%) | Permeability* (mD) |
|------------|----------------------------------|----------------|----------------------------------|-------------------------------|---------------------------------|---------------|----------------|-------------------|
| SGT 1-4-3 | 988                              | 90.3           | 599                              | 1.37                          | 0.51                            | 0.98          | 0.84           | 0.0545            |
| SGT 1-7-A | 89.4                             | 105            | 233                              | 0.71                          | 0.15                            | 1.35          | 1.19           | 0.00233           |
| SGT 4-28-F| 7967                             | 37.1           | 5351                             | 4.22                          | 0.14                            | 3.61          | 1.82           | 0.00505           |
| SGT 4-30-E| 277                              | 149            | 83                               | 2.21                          | 1.20                            | 5.16          | 2.78           | 0.0248            |
| SGT 5-47-A| 2246                             | 178            | 436                              | 2.19                          | 0.35                            | 3.45          | 6.71           | 0.140             |
| SGT 6-49-A| 66.3                             | 63.1           | 589                              | 3.05                          | 0.77                            | 0.49          | 2.30           | 0.00122           |
| SGT 6-56-2| 12.0                             | 12.6           | 1951                             | 2.90                          | 0.83                            | 2.48          | 1.85           | 0.463             |
| SHT 1-002-3| 456                             | 34.1           | 989                              | 2.07                          | 0.50                            | 1.24          | 2.08           | 0.00135           |
| SHT 1-008-2| 304                             | 14.5           | 167                              | 1.46                          | 0.78                            | 2.04          | 1.52           | 1.14              |
| SHT 1-011-2| 92.7                            | 78.6           | 365                              | 1.27                          | 0.37                            | 0.71          | 3.23           | 0.0758            |
| SHT 1-018-1| 529                             | 84.3           | 814                              | 2.42                          | 0.45                            | 1.09          | 2.90           | 0.00448           |
| SHT 3-030-3| 4143                            | 403            | 433                              | 1.54                          | 0.23                            | 2.37          | 1.83           | 0.00341           |
| SHT 3-041-3| 3712                            | 719            | 489                              | 1.46                          | 0.17                            | 1.83          | 1.27           | 0.296             |
| SHT 3-098 | 2644                             | 181            | 1427                             | 2.55                          | 0.23                            | 2.13          | 2.63           | 0.0649            |
| SHT 4-091-D| 87.3                            | 82.2           | 167                              | 1.61                          | 0.70                            | 2.06          | 3.02           | 0.00333           |
| SHT 5-107-3| 22.1                            | 120            | 167                              | 2.22                          | 0.57                            | 1.06          | 2.79           | 0.0998            |
| SHT 5-108-D| 221                             | 205            | 234                              | 1.92                          | 0.77                            | 1.07          | 1.50           | 0.0154            |
| SHT 6-133-1| 486                             | 234            | 233                              | 1.57                          | 0.45                            | 2.44          | 2.55           | 0.00545           |

Avg ± std dev 1352 ± 2107 152 ± 171 818 ± 1231 15 ± 12 2.04 ± 0.81 0.51 ± 0.29 1.98 ± 1.18 2.38 ± 1.29 0.133 ± 0.279

*When pore-throat diameter corresponds to 50% of total cumulative intrusion volume (by volume); \(V\) = total pore volume; \(A\) = surface area. *Porosity and permeability obtained from gas (helium) measurements.

*Porosity obtained from vacuum saturation (DI water).
capillary tube $N(r)$ can be calculated by the cumulative volume of mercury intrusion $V_{Hg}(r)$, which can be expressed by

$$N(r) = \frac{V_{Hg}(r)}{\pi r^2 l},$$

(6)

where $l$ is the length of a capillary tube. Then substituting Equation (6) into Equation (4) yields

$$\frac{V_{Hg}(r)}{\pi r^2 l} \propto r^{-D_f}.$$

As the length of capillary tube is a constant, thus, Equation (7) is simply expressed as

$$V_{Hg}(r) \propto r^{2-D_f},$$

(8)

and $V_{Hg}$ can be substituted by the mercury saturation $S_{Hg}$; moreover, according to Equation (1), pore radius $r$ could be associated with capillary pressure $P_c$, thus, the following equation can be obtained:

$$S_{Hg}(r) \propto P_c^{-(2-D_f)}.$$

(9)

As revealed by Equation (9), the value of fractal dimension $D_f$ can be obtained from the slope of the linear regression of $\log S_{Hg}$ versus $\log P_c$ in a log-log plot.

3.3. Field Emission-Scanning Electron Microscopy (FE-SEM). The FE-SEM imaging method provides information about the morphology of micro- to nanoscale pores and throats in the samples. Both backscattered electron (BSE) and secondary electron (SE) modes were used to observe cross-sections of six representative carbonate samples at magnification scales from 200 to 20000. Before imaging with FE-SEM (Zeiss Merlin Compact), the sample was firstly cut at right angles to the bedding plane. To obtain an extremely flat plane for better observation, fine grinding was carried out using a Leica EM TXP with a sequence of 9 μm, 2 μm, and 0.5 μm abrasive papers and finally ion milled by Ion Beam Milling System (Leica EM TIC 3X) for two hours [39]. During the milling process, two accelerating voltages of 5.5 kV and 2.0 kV were selected alternately for 4 rounds of milling [40]. The edge of each sample was coated with a conductive carbon adhesive to improve electrical conductivity.

3.4. Vacuum Saturation. The open porosity of carbonates core samples was obtained by vacuum saturation of DI water. The first sample chamber was evacuated to 0.05 Torr (1 Torr = 1 mm Hg = 133.3 Pa), equivalent to a 99.993% vacuum [41] and keeping this pressure for 6 h. Then, a saturating fluid (DI water) was injected into the vacuumed chamber under the pressure of 10-15 MPa, until the sample was immersed, and the fluid would occupy the evacuated open porosity. After 12 h, the sample was removed from the chamber and the open porosity could be obtained by the changes of samples weight.

3.5. Contact Angle Measurement. The contact angle refers to the angle between the liquid-solid interface and the solid-liquid interface when the tangent line of the gas-liquid interface is made at the intersection of the three phases. The measurement of contact angle is a quick and quantitative technology to evaluate the wettability of rock, which has clear mechanical and thermodynamic properties [42]. In this study, the contact angle between deionized (DI) water and carbonate samples was measured by using a droplet of 2 μL fluid on a flat surface (polished with 200 grit sandpaper) of a 1 cm × 1 cm sample piece and a contact angle meter and an interface tensiometer (Model SL200KB, USA Kino Industry Co.), and the wettability was quantitatively evaluated. In order to obtain correct contact angle, the focus should be adjusted to make the clear image of the injection needle during the measurement process, and the needle should be moved to the center of the view field through the fine-tuning knob. When the liquid drops on the sample, capture the shape picture of the liquid drop, select the measurement reference line, and then identify the outline of the liquid drop to directly measure the contact angle. The measurement method used in this study is circular fitting, and the accuracy of the measurement result is ±1°.

3.6. Spontaneous Imbibition. Spontaneous fluid imbibition tests were carried out on six representative carbonate samples, and distilled (DI) water was used as the displacement fluid to replace the air in the pore space. For the purpose of minimizing the effect of vapor absorption, four sides of each cubic sample were coated with quick-cure epoxy before the test. The top and bottom surfaces were left untreated, so imbibition could take place. The same with the MIP tests, the samples were drying in a 60°C oven for 48 hours and cooled to 23°C (room temperature). The experimental procedure of imbibition tests, as well as the data processing, has been described in detail by Hu et al. [43]. In brief, for the imbibition test, the bottom surface of the cubic sample was submerged in DI water to a depth of about 1 mm. Several beakers of water were placed inside the test chamber to maintain the environment with high and constant relative humidity [44, 45]. The imbibed mass of DI water over time was recorded by a high-precision microbalance with a readability of 0.01 mg (Shimazu, Model AUV220WD) connected to a computer for periodic recording of the balance weights.

4. Results and Discussion

4.1. Petrography of Carbonate Samples and Reservoir Quality. The original characteristics of the pores in the Xiaoerbulaake Formation have almost been completely destroyed due to its deep burial and multistage diageneric modifications, and the reservoir pore space is now mainly composed of composite genetic pores (secondary transformed primary pores) and secondary pores and fractures [17]. From directly observations of outcrop samples and thin sections, we found that the samples in this study are mainly fine-medium grained crystalline dolomites (Figure 3(a)) and micritic dolomites (Figure 3(d)); in addition, dolarenite (Figure 3(b)) and microbial dolomites (Figure 3(c)) are occasionally observed. Two
dolomite textures are also observed in these samples, namely, matrix dolomites and dolomite cements (Figure 3(i)) [21]. Using the porosity type classification of Choquette and Lloyd [46] and the sample observation of thin sections by optical microscopy and FE-SEM images, the pore systems of the Xiaerbulake Formation samples are dominated by three types of pores, ranging in size from nanometers to microns: intergranular pores, intragranular pores, and intercrystalline pores (Figures 3(g)–3(i) and 4); also micro- and nanoscale fractures are observed (Figures 5 and 6). Additionally, two or more pore types could be observed in adjacent areas, which indicate the different types of pores are developed together in the Xiaerbulake Formation carbonates.

Typical FE-SEM images of carbonate samples from Xiaerbulake Formation are presented in Figure 4. It shows the presence of intergranular pores in Figures 4(a) and 4(b), intercrystalline pores in Figures 4(c) and 4(d), and intragranular pores in Figures 4(e) and 4(f). Intergranular pores in samples are heterogeneous and irregular with pore sizes > 10 μm (Figures 4(a) and 4(b)). The pore size distribution of intercrystalline pores ranges from 100 nm to 10 μm (Figures 4(c) and 4(d)). Intragranular pores...
are mostly circular, linear, and angular (Figures 4(e) and 4(f)), and the pore shapes of the well-developed intragranular dissolution pores vary from nearly circular to irregular (Figures 4(g)–4(i)). Generally, the pore size distribution of intragranular and dissolution pores ranges from 10 nm to 1 μm. Microfractures with apertures ranging from nm- to μm-scale are developed in several samples, but they are filled with various types of cements including dolomite, quartz, and calcite (Figure 3(e)). The various pore types and micro-lithologies in our samples give rise to variable and heterogeneous pore systems, and these will be described in Section 4.3.

4.2. Porosity Obtained by Different Methods. The helium porosity and permeability results of outcrop samples indicate relatively poor reservoir quality of the Xiaoerbulake Formation. The porosity is in the range of 0.49%–5.16%, with an average of 1.98%, and the permeability is from 0.001 mD to 1.140 mD, and the average permeability is 0.133 mD.

The open porosity of outcrop samples was measured by vacuum saturation (DI water), and the results are listed in Table 1. Generally, the vacuum saturation porosity is lower than gas porosity considering the unconnected pores. However, the average vacuum saturation porosity of samples is 2.38%, which is higher than the average gas porosity (1.98%). The wettability of samples has impact on the vacuum saturation porosity results. The contact angle measurements of these samples with DI water show 47 degrees on average (from 34 to 82 degrees, Figure 7), indicative of their water-wet nature (in the air). Thus, the saturation porosity could be overestimated. In addition, the wells drilled in Xiaoerbulake Formation are mainly producing gas; we believe the gas porosity results of study samples are more reliable.

4.3. Pore Structure Characterization. Through the MIP tests and data analysis, the pore structure and pore size distributions of 18 carbonate samples were investigated. As shown in Table 1, both nm- and μm-sized pores are developed in the carbonate samples, with the median pore-throat diameters ranging from 12 nm to 7967 nm, which indicates a wide spectrum of pore-throat sizes. On average, pores with throat
sizes of >10 μm account for 18.2% of the total pore volume, throat sizes of 1-10 μm for 25.1%, throat sizes of 0.1-1 μm for 28.4%, and throat sizes of 10-100 nm for 27.9% (Table 2). Carbonate samples have different pore-throat size distributions in μm-nm ranges, and as we referred above, the pore systems of these samples are various.

As described in the study of Gao and Hu [47], the critical (threshold) pressure $P_t$ of each of multiple connected pore networks can be obtained from the inflection point, the maximal location between the difference of intrusion volume was divided by the difference of logarithmic pore-throat diameter for two neighboring data points [48], and the values of $L_{max}$ and permeability can then be obtained.

Inflection points can be observed from the plot of log differential intrusion vs. intrusion pressure (numbered on the Figures 8(a), 8(c), and 8(e)), which indicates different connected pore networks [48]. In general, four inflection points are observed in μm- and nm-scales for all carbonate samples, which suggests four connected pore networks. The average corresponding critical pore-throat diameter of the 1st to 4th inflection points is 22.8 μm, 5.39 μm, 0.500 μm, and 50.5 nm, from the pore networks located at the intervals of 10 μm–45 μm, 1–10 μm, 0.1–1 μm, and 10–100 nm, respectively (Table 1). Based on inflection points and pore-throat size distributions, the pore systems of carbonate samples can be divided into three types (Table 2). For samples belonging to Type I, the pore networks are dominated by pore diameters at the nm-scale (10 nm < pore-throat diameter < 1 μm) with an average median pore-throat diameter of 180 nm, and the pores are dominated by intragranular (dissolution) pores. Figures 8(a) and 8(b) show plots of incremental intrusion and pore volume percentage distribution from MIP of a typical Type I sample (SGT 4-30-E). This sample has a gas porosity of 5.16% and a median pore-throat diameter of 277 nm, with nearly 95% of the pore-throat sizes located in the 100 nm to 1 μm range. This result also explains why there are no evident pores in the thin section of this sample (Figure 9(a)), but the porosity is relatively high, which could be due to nm-size intragranular pores observable by FE-SEM (Figures 9(b)–9(d)).

Type II samples have a pore system dominated by both μm-scale (pore-throat diameter > 1 μm) and nm-scale (10 nm < pore-throat diameter < 1 μm) pore diameter networks, with an average median pore-throat diameter of 341 nm, and the pore system is a mix of different pore types. As shown in Figures 8(c) and 8(d), the gas porosity of the Type II sample (SGT 6-49-A) is mainly composed of pores with pore-throat diameters of >1 μm and 10 nm-100 nm, with the proportion of about 40% and 50% of the total pore volume, respectively. The porosity of this sample is 0.49% with the median pore-throat diameter of 66.3 nm (Table 1).
The photomicrographs also illustrate the mixed pore system. From the thin section of this Type II sample, some intergranular pores and intercrystalline pores ranging from 5\( \mu \text{m} \) to 50\( \mu \text{m} \) are observed (Figure 9(e)), and intragranular and dissolution pores in the range from 10\( \text{nm} \) to 100\( \text{nm} \) are found (Figures 9(f)–9(h)).

Type III samples have pore systems dominated by \( \mu \text{m} \)-scale pore networks, with pore-throat diameters > 1\( \mu \text{m} \) and an average median pore-throat diameter of 4.14\( \mu \text{m} \); the pore types are dominated by intergranular and intercrystalline pores. Plots of incremental intrusion and pore volume percentage distribution of the typical Type III sample (SGT 5-47-A) are shown in Figures 8(e) and 8(f); pores with pore-throat diameters of >1\( \mu \text{m} \) account for nearly 70% of the total pore volume. The observations of the thin section and FE-SEM are consistent with the MIP results. Intragranular (dissolution) pores with pore-throat diameters < 1\( \mu \text{m} \) rarely are found, while the intergranular pores ranging
from 10 μm to 50 μm and intercrystalline pores ranging from 1 μm to 10 μm are more frequently observed (Figures 9(i) and 9(j)).

4.3. Permeability of Multiple Connected Pore Networks. According to Equation (2) and inflection points and threshold pressures from MIP data, the permeability of each connected pore network with pore-throats covering different ranges (micro- to nanoscale) can be obtained. Table 3 displays the calculated permeability values for four pore diameter ranges for carbonate samples, the corresponding threshold pressures, and the critical pore-throat diameters. The values of calculated permeability and corresponding critical pore-throat diameter decrease over several orders of magnitude with increasing threshold pressure. The calculated permeability of pore networks with pore-throat diameters > 10 μm is in the range of 0.14–12.5 mD, which is comparable to the air permeability of carbonates dominated by intergranular and dissolution pores on the nm-scale [17, 49].

These results suggest that μm-scale pore networks dominated by intergranular or intercrystalline pores can provide significant permeability, which may in turn make a contribution to the ability of oil to move, or migrate, within carbonate reservoirs.

In this work, the permeability contribution values of multiple pore networks were obtained by the equation proposed by Purcell [50]:

\[
\Delta K_{ci} = \frac{\Delta K_{mi}}{\sum_{i=1}^{n} \Delta K_{mi}},
\]

\[
\Delta K_{mi} = \frac{1}{2} \left( \frac{1}{\pi \Delta P_{ci}} + \frac{1}{\pi \Delta P_{ci+1}} \right) \Delta S_{ci+1},
\]

where \(\Delta K_{ci}\) is the permeability contribution value of pore network with different ranges of pore-throat diameters, \(i\) represents the interval number of pore network, \(\Delta S_{ci+1}\) is the cumulative volume of intruded mercury at different intervals, and \(\Delta P_{ci}\) is the capillary pressure at different intervals. The intervals were obtained by the inflection points shown in Figure 8, and the \(\Delta P_{ci}\) is equal to the threshold pressure.

The distributions of pore volume and corresponding permeability contributions were calculated and are shown in Table 2. It shows that even though pore-throat diameter >
10 μm makes up only 18.2% on average of total pore volume, their average contribution to the permeability is 86.8%, suggesting that for carbonates from Xiaoerbula Lake Formation, the pore networks with pore-throat diameter > 10 μm are the main reservoir permeability channel. Therefore, the relatively highly interconnected intercrystalline pores and intergranular pores are the main contributors to the overall permeability. On the other hand, the proportion of nanoscale.
pores is 56.7%, which becomes the main reservoir storage space, even though its contribution to permeability is limited. The poor connectivity of the pore networks at the nanoscale may explain the phenomenon of high porosity with low permeability, which is in keeping with the observation results of the FE-SEM (Figures 4(e) and 4(f)). It can be concluded that the permeability is mainly controlled by a small number of μm-size pores for most of the samples.

4.4. Fractal Dimension of Pore Networks. The curve of mercury saturation vs. the capillary pressure can be used to determine whether samples conform to the fractal characteristics. If it is a straight line on a log-log plot, the pore structure can be characterized by fractal dimensions [51]. However, the statistical results of studied samples show that there is no linear relationship between log mercury injection capillary pressure and log mercury saturation. Considering the multiple connected pore networks in carbonate samples discussed before, we divide the fractal dimensions into a four-segment pattern basing on the inflection points, and good linear relationships are found, respectively, for each pore network (Figure 10). This finding indicates the heterogeneity and complexity of the pore surfaces and distribution within different pore-size ranges and pore types.

According to Equation (8), fractal dimensions of multiple pore networks can be calculated from the slope of each fitted line (Figure 10). The calculated fractal dimensions of multiple pore networks are expressed as $D_{11}$, $D_{12}$, $D_{23}$, and $D_{34}$, respectively. Generally, the correlation coefficient of each segment is higher than 0.9, which is good (Table 4). Because each segment was decided by an inflection point (with corresponding characteristic length and threshold pressure), the fractal dimension of each segment can be correlated loosely to the pore networks located at the intervals of >10 μm, 1-10 μm, 0.1-1 μm, and 0.01-0.1 μm, respectively. The results suggest that the values of fractal dimension for the pores with larger pore-throat diameters are greater than those of pores with smaller pore-throat diameters. It may indicate that the larger pores have more complex structure (such as rough surface and irregular size), whereas the pore networks with smaller pore-throat diameters are relatively homogenous. The photomicrographs (Figures 4 and 9) show comparable results: the intragranular pores are mostly circular, linear, and angular, while the intergranular pores and intercrystalline pores are more heterogeneous and irregular.

However, fractal dimensions greater than three are found in a few samples (SGT 1-7-1, SHY 3-030-3, and SHY 3-041-3). According to fractal theory, the fractal dimensions should be less than the physical dimension of three. The invalid value may be due to the oversimplification of the assumption that micro-scale pores are cylindrical. Song et al. reported a similar result (>3) which may be related to the existence of microfractures with the more complex and rough structure in the sample [52]. From the thin section images, microfractures are actually developed in the three samples with $D_1 > 3$ (Figure 5). Furthermore,
Table 3: Pore network diameter ranges and associated parameters from MIP tests.

| Sample       | \(P_t\) (MPa) | \(L_t\) (μm) | Calculated permeability (mD) | \(P_t\) (MPa) | \(L_{t1}\) (μm) | Calculated permeability (mD) | \(P_t\) (MPa) | \(L_{t2}\) (μm) | Calculated permeability (mD) | \(P_t\) (MPa) | \(L_{t3}\) (μm) | Calculated permeability (mD) | \(P_t\) (MPa) | \(L_{t4}\) (μm) | Calculated permeability (mD) |
|--------------|----------------|--------------|----------------------------|----------------|----------------|----------------------------|----------------|----------------|----------------------------|----------------|----------------|----------------------------|----------------|----------------|----------------------------|
| SGT 1-4-3    | 0.117          | 12.8         | 0.14                       | 0.406          | 3.68           | 0.092                     | 6.89           | 0.217          | 0.0006                     | 68.9           | 0.021          | 0.00001                    | 100             | 0.021          | 0.00001                    |
| SGT 1-7-A    | 0.069          | 21.9         | 0.32                       | 0.271          | 5.54           | 0.092                     | 1.37           | 1.100          | 0.0071                     | 20.7           | 0.071          | 0.00007                    | 100             | 0.021          | 0.00007                    |
| SGT 4-28-F   | 0.083          | 18.2         | 2.50                       | 0.406          | 3.68           | 0.191                     | 2.75           | 0.547          | 0.0046                     | 68.9           | 0.021          | 0.00001                    | 100             | 0.021          | 0.00001                    |
| SGT 4-30-E   | 0.069          | 24.7         | 3.83                       | 0.207          | 8.22           | 0.348                     | 3.78           | 0.449          | 0.0345                     | 14.4           | 0.123          | 0.00317                    | 100             | 0.021          | 0.00001                    |
| SGT 5-47-A   | 0.138          | 10.9         | 3.83                       | 0.548          | 2.76           | 0.324                     | 2.20           | 0.684          | 0.0170                     | 26.2           | 0.056          | 0.00019                    | 100             | 0.021          | 0.00019                    |
| SGT 6-49-A   | 0.069          | 24.7         | 6.21                       | 0.270          | 6.39           | 1.137                     | 6.20           | 0.273          | 0.0024                     | 35.1           | 0.047          | 0.00013                    | 100             | 0.021          | 0.00013                    |
| SGT 6-56-2   | 0.069          | 21.9         | 1.37                       | 0.241          | 6.35           | 0.377                     | 2.47           | 0.607          | 0.0017                     | 68.9           | 0.021          | 0.00000                    | 100             | 0.021          | 0.00000                    |
| SHY 1-002-3  | 0.055          | 27.4         | 1.62                       | 0.239          | 6.35           | 0.219                     | 3.43           | 0.437          | 0.0023                     | 68.9           | 0.021          | 0.00001                    | 100             | 0.021          | 0.00001                    |
| SHY 1-008-2  | 0.165          | 9.2          | 0.89                       | 1.235          | 1.22           | 0.034                     | 14.47          | 0.102          | 0.0004                     | 24.8           | 0.059          | 0.00034                    | 100             | 0.021          | 0.00034                    |
| SHY 1-011-2  | 0.138          | 10.9         | 0.61                       | 0.615          | 2.45           | 0.054                     | 4.13           | 0.363          | 0.0008                     | 35.1           | 0.041          | 0.00005                    | 100             | 0.021          | 0.00005                    |
| SHY 1-018-1  | 0.048          | 31.3         | 4.30                       | 0.207          | 7.28           | 0.862                     | 2.75           | 0.547          | 0.0089                     | 48.2           | 0.030          | 0.00004                    | 100             | 0.021          | 0.00004                    |
| SHY 3-030-3  | 0.055          | 27.4         | 3.18                       | 0.238          | 6.35           | 0.775                     | 14.46          | 0.102          | 0.0003                     | 30.3           | 0.048          | 0.00012                    | 100             | 0.021          | 0.00012                    |
| SHY 3-041-3  | 0.048          | 31.3         | 2.52                       | 0.165          | 9.20           | 0.891                     | 3.44           | 0.437          | 0.0040                     | 35.1           | 0.041          | 0.00009                    | 100             | 0.021          | 0.00009                    |
| SHY 3-098    | 0.041          | 41.2         | 12.48                      | 0.200          | 8.50           | 0.487                     | 1.92           | 0.886          | 0.0099                     | 51.6           | 0.032          | 0.00002                    | 100             | 0.021          | 0.00002                    |
| SHY 4-091-D  | 0.179          | 8.4          | 0.72                       | 0.955          | 1.58           | 0.057                     | 4.13           | 0.363          | 0.0048                     | 23.4           | 0.063          | 0.00034                    | 100             | 0.021          | 0.00034                    |
| SHY 5-107-3  | 0.200          | 7.5          | 0.54                       | 0.407          | 3.68           | 0.824                     | 1.93           | 0.783          | 0.0507                     | 26.2           | 0.056          | 0.00062                    | 100             | 0.021          | 0.00062                    |
| SHY 5-108-D  | 0.041          | 39.9         | 2.19                       | 0.231          | 6.35           | 0.375                     | 6.89           | 0.217          | 0.0049                     | 26.2           | 0.056          | 0.00029                    | 100             | 0.021          | 0.00029                    |
| SHY 6-133-1  | 0.041          | 39.9         | 4.55                       | 0.200          | 7.49           | 0.526                     | 1.72           | 0.879          | 0.0190                     | 14.5           | 0.102          | 0.00060                    | 100             | 0.021          | 0.00060                    |
| Average      | 0.090          | 22.8         | 2.88                       | 0.391          | 5.39           | 0.426                     | 4.72           | 0.500          | 0.0097                     | 38.2           | 0.051          | 0.00034                    | 100             | 0.021          | 0.00034                    |

\(L_t\): the characteristic length is the pore-throat diameter corresponding to the critical (threshold) pressure \(P_t\).
Liu et al. suggested the upper value 3 indicates a totally irregular or rough surface [53]. Thus, the values between 3 and 4 obtained in this study are considered the result of microfractures and physically reasonable.

4.5. Connectivity of Pore Networks. Spontaneous imbibition is the invasion of wetting fluid into a porous medium by capillary forces [54, 55]. For unconventional reservoirs, spontaneous imbibition is the primary mechanism responsible for enhanced oil production and an effective oil recovery method [56–58]. Previous studies have concluded that the spontaneous imbibition process is primarily controlled by the pore structure of the porous media, as well as the physical properties of fluids and interactions between them [55, 57]. Thus, the pore structure and the hydrocarbon production behavior can be better understood by studying the spontaneous imbibition process. Handy [59] proposed that plotting cumulative imbibition height against imbibition time on a log-log scale would in theory give a slope of 1/2 for porous media with well-connected pore networks [60]. However, a 1/2 slope is not always obtained for natural rocks. Based on the percolation theory [61, 62], a lower slope value (<1/2) may suggest poorer pore connectivity [60, 63]. Hu et al. [63] observed a 1/2 slope for Berea sandstone indicative of a well-connected pore space and an imbibition slope of 1/4 for well-cemented Indiana sandstone of low pore connectivity. According to Hu et al. [63] and Yang et al. [64],

![Figure 10: Fractal dimension calculation with a tubular pore model (D = 2 + slope) using four-straight-line fitting.](image)
the imbibition rate can be indicated by the slope of the straight lines, and afterward, the connectivity of pore networks could be qualitatively assessed by it.

Spontaneous imbibition tests using DI water were conducted on six representative samples. The plots of DI water imbibition behavior are shown in Figure 11. The imbibition curves are generally composed of two stages: rapid increasing stage at the beginning and stably increasing stage. At the beginning of the test (1-2 minutes), with increasing imbibition time, the log cumulative imbibition increases rapidly and some fluctuations may occur (e.g., Figure 11(d)), which may be caused by unstable sample and the boundary effects. After that, the log cumulative imbibition increases stably and linear relationships which have different slopes can be observed. When the sample is saturated with imbibition fluid, the straight line paralleled to the x-axis will appear (the green line, Figure 11(c)). Except for sample SGT 6-56-2 and SHY 1-002-3 (Figures 11(e) and 11(f)), only one slope is evident in the stably increasing stage for three other samples (the blue line). These results are at first sight in contrast with the MIP results; namely, that there are different connected pore networks in all six samples.

A second stable slope is observed after a long time period of imbibition in the curves of samples SGT 6-56-2 and SHY 1-002-3 (the green line in Figures 11(e) and 11(f)). Based on the FE-SEM images, micro- to nanoscale fractures were observed in these two samples. As shown in Figure 6, fractures at nm-scales are developed in sample SHY 1-002-3 which connect the intragranular (dissolution) pores and intergranular pores. Moreover, dissolution pores associated with the fractures are observed. From the fractal dimension of these six samples (Table 4), it can be found that the fractal dimension values of pores ranging in 10 nm-100 nm ($D_f$) of samples SGT 6-56-2 and SHY 1-002-3 are higher than the average value, especially for sample SGT 6-56-2, whose fractal dimension is as high as 2.95. As we mentioned in Section 4.4, because of its more complex shape and rough edge, the fractal dimension of fracture will be higher, even more than 3. This is consistent with observation of FE-SEM. Additionally, the MIP result shows that for sample SHY 1-002-3, 44% of the whole pores are in the 10-100 nm range, and 35% are in the 1-10 µm range; and for sample SGT 6-56-2, 17.9% of the whole pores have pore-throat diameter > 10 µm, and 72.1% are ranging in 10-100 nm. Therefore, the occurrence of two different slopes could be explained by two relatively developed well-connected pore networks and the existence of fractures at micro- to nanoscale. However, according to Hu et al. [63], spontaneous imbibition of a wetting fluid into a well-connected porous material produces a late-time imbibition slope ($d \log (\text{mass imbibed})/d \log (\text{time})$) of approximately 0.5; an imbibition slope of 0.25 indicates that the sample has a relatively poor connectivity. The imbibition slopes of selected samples are all around 0.30 or even lower than 0.25, which may indicate the poor to moderate pore connectivity of pore networks in these carbonate samples from Xiaoerbulake Formation. The intragranular (dissolution) pores account nearly half of the total pore volume, while the pores are well-developed in the granular, the poor pore connectivity limits the permeability, and thus the fractures made by an oil recovery method may significantly improve the reservoir quality.

As shown in Figure 12, the relationship between spontaneous imbibition slope with the proportion of pores of pore-throat diameter > 10 µm shows a positive correlation ($R^2 = 0.8$). Combined with the permeability contribution of different pore networks, it is obvious that pore networks located at µm-scale are the most important permeability channel for samples from Xiaoerbulake Formation, even though its pore volume is not predominant in the total porosity. Furthermore, pore types in samples from Xiaoerbulake Formation were identified before; it could be concluded that unless there is micro-nano-fracture development, the pore networks dominated by intragranular pores have the best connectivity, while those predominated by intragranular and dissolution pores have the relatively low pore connectivity.

Additionally, the effective tortuosity can be calculated by Equation (3) (Table 1). The value of tortuosity for pore networks ranging from 10 nm to 100 nm is as high as 818 ± 1231. Put another way, the effective diffusion coefficient for nonsorbing gas and oil molecules in carbonates will be in the order of 10-8 and 10-12. These relatively large values of tortuosity imply that, in order to migrate from one location to another, fluid within the nano-scale pore network will need to make its way through some tortuous pathways. The geometrical tortuosity $L_r/L$ of 2.04 ± 0.81 means that fluid has to actually travel 2.04 ± 0.81 cm to reach a point 1 cm away. This is consistent with the imbibition results that the pore networks ranging in nm-scale of the carbonates are
Figure 11: Spontaneous imbibition results for six representative carbonate samples from the Xiaoerbulake Formation.
poorly connected; therefore, much time is required for fluid to find connected pathways to travel a limited distance [44]. This section may be divided by subheadings. It should provide a concise and precise description of the experimental results, their interpretation as well as the experimental conclusions that can be drawn.

5. Conclusions

In the present work, the nature and connectivity of pore networks in 18 carbonate samples from two outcrop locations of the Xiaoerbulake Formation have been characterized by combining the methods of MIP, FE-SEM, spontaneous imbibition, and fractal dimensions analyses. The following conclusions can be drawn:

1. The lithologies are dominated by micritic dolomites, finely to medium to coarsely crystalline dolomites, microbial dolomites, and dolarenite. Three main types of pores within micro-nano-scale were identified by combining MIP analyses with photomicrographic observations (both optical microscope and FE-SEM), namely, intergranular pores, intercrystalline pores, and intragranular pores (dissolution pores).

2. The Xiaoerbulake Formation carbonates are characterized by complex multiscale pore networks. Four different pore networks ranging in nm-μm spectrum are identified by MIP. Based on the pore volume distributions of the four different pore-throat diameter ranges, three types of pore network patterns were identified. Multiple fractal characteristics show pore networks with larger pore throat diameter have more complex structure (more irregular shape and rough surface).

3. The permeability is controlled by pore networks in microscale, which means the interparticle pores and intercrystalline pores make a considerable stronger contribution to permeability. Even though pore-throat diameter > 1 μm makes up only 43.3% on average of total pore volume, their average contribution to the permeability is 99.64%.

4. The spontaneous imbibition tests show that the connectivity of pore networks is controlled by pore type; the Type III pattern pore networks dominated by μm size pores are better connected. Generally, the pore networks in Xiaoerbulake samples exhibit poor to moderate pore connectivity. Nevertheless, the development of fractures ranging from μm to nm is beneficial for the connectivity greatly by connecting different pore types, such as among intragranular (dissolution) pores as well as between intragranular (dissolution) and intergranular or intercrystalline pores.

Data Availability

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

Conflicts of Interest

The authors declare no conflict of interest.

Authors’ Contributions

Qinhong Hu, Jingyi Wang, and Mengdi Sun are responsible for the conceptualization. Jingyi Wang curated the data. Jingyi Wang, Mengdi Sun, and Tao Zhang did the formal analysis. Mengdi Sun, Zhongxian Cai, and Cong Zhang acquired funding. Qinhong Hu, Cong Zhang, and Tao Zhang are assigned to the methodology. Zhongxian Cai is involved in the project administration. Zhongxian Cai is responsible for the resources. Qinhong Hu performed the supervision. Jingyi Wang wrote the original draft. Qinhong Hu, Mengdi Sun, Zhongxian Cai, Cong Chang, and Tao Zhang wrote, reviewed, and edited the manuscript.

Acknowledgments

The authors sincerely thank the Strategic Priority Research Program of the Chinese Academy of Science (Grant No. XDA14010302), the National Natural Science Foundation of China (Grant Nos. 41802146, 41830431, and 41572134), and the Key Laboratory of Unconventional Oil and Gas Geology, China Geological Survey (No. 30200018-19-ZC0613-0065) for the financial support.

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