Multi-Scale Quantitative Characterization of Pore Distribution Networks in Tight Sandstone by integrating FE-SEM, HPMI, and NMR with the Constrained Least Squares Algorithm

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Abstract: The goal of this study was to investigate the impacts of various sedimentary-diagenetic conditions on the macroscopic petrophysical parameters and microscopic pore structures of tight sandstones from the Lower Jurassic Badaowan Formation in the Southern Junggar Basin, China. Based on the traditional methods for establishing pore size distribution, including integrating the results of high-pressure mercury injection, nuclear magnetic resonance, and scanning electron microscopy, the constrained least squares algorithm was employed to automatically determine the porosity contributions of pore types with different origins. The results show that there are six genetic pore types: residual intergranular pores (RIPs), feldspar dissolution pores (FDPs), rock fragment dissolution pores (RFDPs), clay mineral intergranular pores (CIPs), intercrystalline pores of kaolinite (IPKs), and matrix pores (MPs). Four lithofacies were identified: the quartz cemented-dissolution facies (QCDF), carbonate cemented facies (CCF), authigenic clay mineral facies (ACMF), and matrix-caused tightly compacted facies (MCTF). Modified by limited dissolution, the QCDF with a high proportion of macropores (RIPs, FDPs, and RFDPs) exhibited a slightly higher porosity and considerably higher permeability than those of others. A large number of micropores (MPs, CIPs, and IPKs) in MCTF and ACMF led to slightly lower porosities but considerably lower permeabilities. Due to the tightly cemented carbonates in the CCF, its porosity reduced sharply, but the permeability of the CCF remained much higher those of the MCTF and ACMF. The results highlight that a high proportion of macropores with large radii and regular shapes provide more effective percolation paths than storage spaces. Nevertheless, micropores with small radii and complex pore structures have a limited contribution to flow capability. The fractal dimension analysis shows that a high proportion of MPs is the major reason for the heterogeneity in tight sandstones. The formation of larger macropores with smooth surfaces are more conductive for oil and gas accumulation.

Keywords: tight sandstone reservoir; pore structures; fractal characteristics; diagenesis; least squares estimator
1. Introduction

Tight sandstone reservoirs are regarded as potential unconventional resources and are widely distributed around the world, especially in Western China. Tight sandstone reservoirs are characterized by low porosity and permeability as well as multi-scale pore networks with strong heterogeneity [1,2]. The relationship between their macroscopic properties (e.g., permeability, porosity, and oil/gas saturation) and microscopic parameters (e.g., pore size distribution (PSD), pore geometry, and pore connectivity) weakens with a large proportion of nanoscale pores [3,4]. Therefore, identifying the factors that control the complexity of the pore networks of tight sandstones and clarifying the relationship between the macroscopic reservoir quality and microscopic pore structure are essential for the evaluation of tight sandstone reservoirs.

Variable depositional environment and various diagenetic processes are the main factors that can cause pore networks in tight sandstones to be more complicated and heterogeneous [4,5]. Although many scholars have studied the impacts of diagenetic processes on reservoir quality, controversies remain: (1) original depositional attributes determine pore network heterogeneities in tight sandstones [3]. In general, tight sandstones with a high content of ductile grains, poor sorting, and fine grains experienced stronger compaction, which causes a sharp reduction in the reservoir quality [6–8]. (2) The impact of authigenic clay-related pores (CPs) on reservoir quality remains a controversial issue. Some scholars think that a large amount of CPs could maintain the total storage spaces or slightly increase, while most of these pores are poorly connected, resulting in a severe decrease in seepage capacity [9,10]. However, other scholars suggest that CPs could create seepage paths in sandstone reservoirs [11]. In addition, grain-coating clay minerals can increase the pressure resistance of sandstone and limit the destruction due to compaction [11,12]. (3) Whether dissolution can improve the quality of reservoirs is still unknown. Increasingly more scholars are indicating that the dissolution pores (DPs) rarely provide a large number of pore spaces because of the possibility that the precipitation produced by dissolution occlude the secondary pores [13,14]. Furthermore, the impacts of various sedimentary-diagenetic factors on microscopic pore networks are still poorly studied.

Many scholars have tried to integrate various techniques to describe the multi-scale PSD of tight sandstones [15–17]. Nuclear magnetic resonance (NMR) is an effective tool for non-destructively quantifying the multi-range pore structures of tight sandstone reservoirs [18–20], but the NMR-derived PSD related to the relaxation time (T2) should be transformed to pore size (µm) through integration with other methods. The NMR-derived PSD has been determined with imaging methods (e.g., casting thin sections and field emission scanning electron microscopy (FE-SEM)) using a large amount of statistical multi-scale pore radii data [21]. The combination of the throat size distribution of rate controlled porosimetry (RCP) and PSD of NMR has been attempted, but the integrated parts of two techniques requires further study [11,22–24]. Besides, the integration of nitrogen adsorption and NMR to recover the total PSD of tight sandstones only effectively investigates the configuration of pores <50 nm. Thus, micron-scale pores remain difficult to describe [25,26]. High-pressure mercury injection (HPMI) is often integrated with NMR to reflect tight sandstone PSD [24,27], due to the resultant relatively full range of PSD characterization, although the relationship between T2 spectrums and pore radii directly influences the accuracy of the NMR-HPMI-integrated PSD.

The Lower Jurassic strata in the southern Junggar Basin are characterized by multilayer hydrocarbon sources that are connected with shallowly buried reservoirs and many sets of effective caprocks, which is considered a primary focus of current exploration efforts [28]. Developed in coal-bearing and near-source strata, the tight sandstones of the Badaowan Formation (J1b), at burial depths of 1600–2000 m, experienced complicated diagenesis but still include several excellent reservoirs with extensive dissolution [29]. Moreover, the tight sandstones are characterized by high gas content, and the gas is mainly derived from the coal seams in the braided delta plain of J1b, forming a set of “self-generating and self-accumulating” reservoirs. A series of studies of tight sandstone reservoirs in J1b have been conducted that focus on the evolution of the sedimentary environments [30–32], petrography [33,34], and diagenetic characteristics. However, the heterogeneous
reservoir quality and complex pore networks make further oil exploration more difficult, and the impacts of sedimentary-diagenetic on pore networks in the sandstones of J1b have not been thoroughly investigated yet.

In this study, 13 tight sandstone samples from J1b in the Southern Junggar Basin (China) were obtained, and the methods of casting thin sections, X-ray diffraction (XRD), FE-SEM, HPMI, and NMR are used to achieve the following goals: (1) characterize the macroscopic heterogeneities (lithofacies, genetic pore types, fluid mobilities, and petrophysical properties) of tight sandstones under different sedimentary-diagenesis conditions; (2) describe the characteristics of microscopic pore networks (pore structures and fractal features) and explore the internal connection between macroscopic reservoir heterogeneities and microscopic pore networks. (3) discuss the impacts of sedimentary and diagenesis settings on the macroscopic reservoir heterogeneities and microscopic pore networks in the tight sandstones of J1b.

2. Geological Setting

The Junggar Basin, which is considered a prolific oil basin in China [35], is located in the northern margin of the Tianshan Mountains and has been a continental basin since the early Paleozoic [36,37]. The Southern Junggar Basin is bounded by Jinghe County to the west and the Dashitou area of Mulei County to the east. It extends to North Tianshan (NTS) to the south and to the Urumqi-Erie Road to the north [30] (Figure 1).

Figure 1. (a) Location of the study area, sampled well, and field section; (b) the stratigraphic column of the Badaowan Formation; (c) geological map of the southern Junggar Basin and the location of the study area; and (d) location of the Central Asian Orogenic Belt (modified by [38]).
The Jurassic stratum in the Southern Junggar Basin consists of the Badaowan Formation, Sangonghe Formation, Xishanyao Formation, Toutunhe Formation, Qigu Formation, and Kalazha Formation from old to young [39]. The Lower Jurassic Badaowan Formation unconformably overlies the Triassic Haojiagou Formation of the Triassic. During the early period of the Badaowan Formation, a shallow-water braided delta plain with thin coal seams widely developed in the Southern Junggar Basin, and due to the frequent lake level fluctuations and the southward expansion of the Junggar Basin, the delta plain gradually evolved into a delta front but ultimately transitioned back to a delta plain. The environment of the coal-enriched swamp in the proximal shallow braided river delta provides the basis for the high contents of matrix and kaolinite in the tight sandstones, and these factors created favorable conditions for the densification of sandstones with complex pore structures.

3. Materials and Methods

3.1. Geologic Features of Samples

We collected 49 samples (20 drilling samples in well X1 and 29 field samples) from the J₁b (Figure 1b, Figure A1), including 12 sandy fine gravel samples, 13 coarse sandstone samples, eight medium sandstone samples, and 16 fine sandstone samples. The locations of the sampled well and the field section are marked in Figure 1, and the location of well X1 is on the high part of containing oil and gas geological structure—a short axis anticline in the central of the southern Junggar Basin. All the samples were obtained from the plain and the front of the braided delta (Figure 1).

3.2. Experimental Methods

To comprehensively investigate the pore structures of the tight sandstone reservoirs in J₁b, we performed a series of experiments. First, the types of storage spaces and mineral compositions of 49 samples were analyzed by XRD, casting thin sections, and FE-SEM. The clustering analysis of the petrophysical properties and mineral compositions of 49 samples was conducted by heat map (Figure A1), it is obvious that there are four groups with different mineral compositions and petrophysical properties of 49 samples, and the differences of the petrophysical properties and mineral compositions between well samples and field samples are slight. Then, 13 representative samples with constant mineral compositions, the typical diagenetic characteristics, and the high proportion of regularly shaped pores were selected from the 49 samples, and the fresh samples were formed into cylindrical plungers. After drying, the helium porosity and transient pulse decay permeability were measured under a confining pressure of ~30 MPa. After fully saturating with 10,000 mg/L under 30 MPa for 48 h, the NMR-derived T₂ spectrums were acquired by using 2 MHz MicroMR20-025V at Peking University (Beijing, China). Then, plungers were centrifuged under an equivalent air-water pressure of 208 psi for 1 h, and the T₂ spectra were measured again. The Carr–Purcell–Meiboom–Gill sequence was applied in NMR tests with an echo spacing of 0.2 ms and a waiting time of 5 s. The number of echoes was 1024, and the scanning number was 128. The NMR-derived PSD, pore structure parameters, and porosity were determined in the samples with saturated water and irreducible water contents. Following the NMR tests, the pore structures of the 13 samples were analyzed using HPMI. The HPMI tests were conducted on an AutoPore-IV9500 mercury porosimeter at Peking University (Beijing, China) according to the Chinese Oil and Gas Industry Standard (SY/T) 5346-2012. The intrusion pressure varied from 0.1 to 414 MPa, which corresponds to pore radii 3.6 nm to 1100 µm. In this paper, the petrographic descriptions, mineral compositions, petrophysical parameters (e.g., porosity, permeability, the contents of immovable fluid (BVI) and movable fluid (FFI)) and fracture evaluations are evaluated by ISRM [40].
3.3. Combining NMR and HPMI Methods

Based on the assumption of the ideal pore geometry, the relationship between $T_2$ and the relaxation effect of the rock grain surface can be expressed as [41]:

$$\frac{1}{T_2} = F_s \frac{\rho}{r},$$  \hspace{1cm} (1)

where $r$ is the pore radius, $\mu$m, $F_s$ is the form factor ($F_s = 3$ for spherical pores, and $F_s = 2$ for cylindrical pores), and $\rho$ is the relaxation rate ($\mu$m/ms). However, the actual pore structures are more complex than those of the ideal formation. Several scholars have found that an exponential relationship, rather than a linear relationship, exists between the $T_2$ spectrum (ms) and the pore radius ($\mu$m) [23,27,42]: this finding is also supported by Figure 2b,c; the relationship can be expressed as follow:

$$\frac{1}{T_2} = F_s \frac{\rho}{r^n} = \frac{1}{A r^n},$$  \hspace{1cm} (2)

where $n$ is the power exponent and $A$ is a constant equal to $\frac{1}{F_s r^2}$.

Equation (2) can be reorganized after taking the logarithm of both sides, and $r$ can be expressed as:

$$\ln r = \frac{1}{n} \ln T_2 - \frac{1}{n} \ln C = \frac{1}{n} \ln T_2 + \ln C,$$  \hspace{1cm} (3)

where $C$ is a constant.

![Figure 2.](image)

Figure 2. The process of integrating pore size distribution (PSD) from high-pressure mercury injection (HPMI) and nuclear magnetic resonance (NMR). (a) Cumulative pore volume fractions of HPMI and NMR; (b) linear regression results of the relationship between relaxation time ($T_2$) and pore radius ($r$); (c) power regression of $T_2$ and $r$; and (d) results of PSD derived by the combination of NMR and HPMI.

The NMR $T_2$ spectrum (ms) can be converted into the PSD ($\mu$m) if the constants $C$ and $n$ are calculated. The key point in matching $T_2$ and $r$ is that the PSD from NMR and HPMI have the same cumulative pore volume fraction. The steps of the converting method modified by Huang and Wang [23,27] are simplified as follows: (1) the cumulative pore volume fraction should be calculated based on the NMR and HPMI data. The cumulative pore volume fraction of NMR, which is greater than the maximum injected mercury saturation ($S_{\text{max}}$), should be excluded (Figure 2a). (2) After matching the cumulative pore volume fraction using NMR and HPMI, every cumulative pore volume fraction $P(j)$ has a uniquely corresponding pore radius $r(j)$, and $P(j)$ can correspond to the relaxation time $T_2 (j)$ by cubic spline interpolation of the cumulative pore volume fraction of the NMR. Then, the determined $C$ and $n$ can be used to convert the $T_2$ spectrum into the PSD ($\mu$m, Figure 2d).
3.4. Estimating the Proportion of Different Pores Based on the Least Squares Estimator

Many pore classifications are based on pore sizes without considering the forming mechanism of the pores [43,44]. However, the volume fraction of pores with various geological genesis (e.g., RIPs, DPs, and CPs) would reveal the relationships between the sedimentary-diagenetic conditions and pore structures. In the same study areas, the sizes of pores with the same genesis might be similar, and the pore size ranges of different genetic pore types could overlap. Therefore, it is difficult to obtain accurate pore volume fractions of different genetic pore types from the total PSD by calculating the area ratio. Therefore, the least squares estimator was applied to calculate the pore volume fractions of different genetic pore types for identifying the various characteristics of sedimentary-diagenetic settings.

The total PSD can be expressed as the combination of the PSD of different pore types in a certain proportion [11,45]. This proportion can be approximately considered as the pore volume fraction of different genetic pores.

We assumed that the total PSD derived by NMR-HPMI is a linear combination of the radii probability distributions of different pore types, which is consistent with the assumptions of other studies [43,44]. Thus, the total PSD, \( y(r) \), a function of pore radius \( r \), can be expressed as:

\[
y(r) = \sum_{i=1}^{N} f_i x_i(r)
\]  

(4)

where \( x_i(r) \) is the radii probability distribution of the \( i \)th pore type and \( f_i \) is the proportion of the \( i \)th pore type. \( N \) is the number of pore types. As the total PSD and the PSD of different pore types are determined, the linear combination model can be inverted to estimate the proportion of each pore type. Considering the physical meaning of the proportions of the pore type, an additional unity sum constraint equation can be incorporated to guarantee that the sum of the fractions is 1, and a non-negative constraint is used to avoid negative proportions. Therefore, the constraint condition of Equation (4) is:

\[
s.t \sum_{i=1}^{N} f_i = 1, \quad f_i \geq 0.
\]  

(5)

This overdetermined linear mixing problem, incorporating residual error, can be presented in matrix notation as:

\[
Y = Xf + e
\]  

(6)

where \( X \) is the radii probability distribution matrix of pore types and \( e \) is the error vector that must be minimized to obtain the fraction vector \( f \) that best fits the total PSD \( Y \). This type of problem can be solved in many ways [46–49]. In this research, we used the least square solution, and the fraction vector \( f \) can be computed by:

\[
f = (X^TX)^{-1}X^TY
\]  

(7)

After the successful determination of \( f \), the proportion of each pore type was obtained by decomposing the integrated PSD from NMR-HPMI. Based on Equation (4), the reconstructed PSD can be expressed as the linear combination of the radius probabilities of different pores with the calculated proportions.

3.5. Fractal Analysis Based on the HPMI-NMR Integration

The fractal dimensions have been widely employed to quantitatively characterize the complexity and heterogeneity of tight sandstone reservoirs [50]. Based on recent studies [27,44,51], the number of pores with sizes greater than \( r_o \) (\( N_r \)) can be obtained as:

\[
N_r = \int_{r_o}^{r_{max}} f(r)dr = Br^{-D}
\]  

(8)
where \( r \) is the pore radius (\( \mu m \)); \( r_{\text{max}} \) is the maximum pore radius (\( \mu m \)); \( B \) is the fractal factor; \( f(r) \) is the density function of the pore radii and \( D \) is the fractal dimension of the pore space.

\[
f(r) = \frac{dN_r}{dr} = B' r^{-(D+1)}
\]

where \( B' \) is a proportional constant that equals \((-DB)\). The cumulative pore volumes with radii smaller than \( r \) can be calculated by substituting Equation (10) into Equation (11):

\[
V_r = \int_{r_{\text{min}}}^{r} f(r)Br^3dr = B'' \left( r^{3-D} - r_{\text{min}}^{3-D} \right)
\]

where \( V_r \) is the cumulative volume of pores with radii smaller than \( r \), \( B'' \) is a proportional constant that equals \( B'/\left(3-D\right) \), and \( r_{\text{min}} \) is the minimum pore radius.

Hence, the total pore volumes of samples \( (V_t) \) can be calculated by the following equation:

\[
V_t = B'' \left( r_{\text{max}}^{3-D} - r_{\text{min}}^{3-D} \right).
\]

The relationship between the cumulative pore volume fraction \( (S_v) \) and the fractal dimension can be expressed as follows:

\[
S_v = \frac{V_r}{V_t} = \left( \frac{r - r_{\text{min}}}{r_{\text{max}} - r_{\text{min}}} \right)^{3-D}
\]

Assuming that \( r_{\text{min}} \) is considerably smaller than \( r_{\text{max}} \), Equation (13) can be simplified as:

\[
S_v = \left( \frac{r}{r_{\text{max}}} \right)^{3-D}
\]

Taking the logarithm of both sides produces:

\[
\lg S_v = 3 - D \lg r - (3 - D) \lg r_{\text{max}}.
\]

The pore radii \( r \) could be transformed from the \( T_2 \) using Equation (3), and the fractal dimensions of the pore size distributions could be obtained from the slope of the \( \lg S_v - \lg r \) curves.

4. Results

4.1. Mineral Composition and Petrophysical Parameters of Four Lithofacies

Characterized by a high matrix content, the \( J_1 b \) sandstones mainly include litharenite with minor feldspathic litharenite and lithic arkose. The main type of quartz is monocrystal, and the feldspars within \( J_1 b \) include plagioclase (albite in majority and calcic plagioclase in minority) and K-feldspar. The rock fragments mainly include sedimentary rock fragments, volcanic rock fragments, and small amounts of metamorphic rock fragments. Some authigenic minerals, e.g., calcite, ferrocalcite, kaolinite, illite, illite-smectite mixed layers, and chlorite, prevail in the \( J_1 b \) sandstones.

According to the cluster analysis of mineral compositions, sedimentary-diagenetic processes, and reservoir quality, four lithofacies were identified, including the quartz cemented-dissolution facies (QCDF) (Figure 3a,b), authigenic clay mineral facies (ACMF) (Figure 3c,d), carbonate cemented facies (CCF) (Figure 3e–h), and matrix-caused tightly compacted facies (MCTF) (Figure 3i). Within the abundant detrital quartz grains and quartz cements, the QCDF mainly developed medium- to coarse-grained and well-sorted sandstones. The porosity and permeability of the QCDF is the highest among the four lithofacies. The CCF often has high percentage of carbonate minerals (including calcite, ferrocalcite, and siderite), which could exceed 25.14%. The sandstones with extensive carbonate cement are often poorly sorted and fine to medium-grained. The porosity range of CCF is from 4.19% to 5.42%, and the permeability varies from 0.05 to 0.07 mD. In the ACMF, authigenic kaolinite, chlorite, illite,
and I/S mixed layers with the form of booklet, fibrous, and bridge significantly block the pores in the tight sandstones. Among these authigenic clay minerals, the content of kaolinite is the highest, which varies from 4.742% to 5.599%. The illite content ranged from 3.35% to 3.96%, and the content of illite/smectite mixed layers is lower than that of illite. The chlorite content in the ACMF ranges from 2.66% to 3.14%. The porosity of the ACMF is widely distributed from 7.78% to 11.20%, whereas the permeability is still poor, ranging from 0.037 to 0.079 mD. The MCTF is usually rich in ductile grains (especially matrix) and is characterized by fine grains and poor-sorting, which results in the MCTF experiencing extensive compaction during the burial. The porosity of the MCTF is stable in the range of 7.02% to 7.75%, and the permeability is concentrated at 0.02 mD. The petrophysical properties and the mineral composition results of 13 samples are presented in Table 1.

Figure 3. Casting thin sections of the tight sandstone samples in J1b, showing the main pore types and four types of lithofacies: (a,b) widely developed quartz overgrowth and a large number of dissolution pores (DPs) with siderite rims, well X1, sample 1674.5; (c) the DPs of rock fragments filled with chlorite, well X1, sample 1787.2; (d) fibrous pore-filling illite well X1, sample 1787.2; (e) ferrocalcite occluding the DPs of feldspar, well X1, sample 1882.3; (f) poikilitic calcite filling the residual intergranular pores, well X1, sample 1827.5; (g) cathode luminescence image of two secondary pore-filling ferrocalcite cements and poikilitic calcite cements; (h) siderite and calcite cemented the residual pores, well X1, sample 1882.3; (i) matrix with a widely developed but small proportion of residual intergranular pores, well X1, sample 1714.6. Q, quartz; QG, quartz overgrowth; F, feldspar; RF, rock fragment; Cc/Cc-I, calcite; Cc-II/Fcc, ferrocalcite; Sid, siderite; C, chlorite; I, illite; M, matrix; MOP, moldic pore; FDP, feldspar dissolution pore; RIP, residual intergranular pore; RFDP, rock fragment dissolution pore.
Table 1. Petrophysical parameters and mineralogical compositions of 13 tight sandstone samples.

| Sample | Depth (m) | Lithology          | Porosity (%) | Permeability (mD) | Detrital Quartz (%) | Quartz Overgrowth (%) | Plagioclase (%) | K-Feldspar (%) | Sedimentary Rock Fragments (%) | Igneous Rock Fragments (%) | Metamorphic Rock Fragments (%) | Authigenic Clay (%) | Calcite (%) | Ferrocalcite (%) | Chlorite (%) | Sidereite (%) | Matrix (%) | Lithofacies |
|--------|-----------|--------------------|---------------|------------------|---------------------|----------------------|------------------|---------------|-----------------------------|--------------------------|--------------------|--------------------|-------------|--------------|-------------|-------------|-----------|-------------|
| 1879.5 | 1879.5    | Coarse sandstone   | 4.956         | 0.066            | 34.159              | 1.332                | 4.597            | 9.195         | 10.768                      | 5.569                    | 1.745              | 3.348              | 1.59        | 2.343        | 1.088       | 6.857       | 1.523     | 5.334       | 2.710     | CCF         |
| 1882.3 | 1882.3    | Sandy fine gravel  | 5.424         | 0.069            | 22.292              | 1.261                | 10.007           | 3.336         | 21.309                      | 3.184                    | 2.228              | 3.167              | 0.985       | 1.126        | 1.759       | 22.391      | 2.749     | 0           | 5.620     | CCF         |
| 1827.5 | 1827.5    | Sandy fine gravel  | 4.186         | 0.055            | 23.65               | 1.54                 | 19.366           | 7.262         | 12.025                      | 10.938                   | 0.667              | 2.931              | 0.596       | 1.246        | 2.565       | 8.947       | 0          | 0           | 4.187     | CCF         |
| 1714.6 | 1714.6    | Fine sandstone     | 7.752         | 0.026            | 27.689              | 0.639                | 6.763            | 4.509         | 14.802                      | 6.585                    | 6.43               | 1.215              | 0.289       | 1.013        | 0.376       | 2.431       | 2.431     | 0           | 18.162    | MCTF        |
| 1713   | 1713      | Fine sandstone     | 7.023         | 0.02             | 26.546              | 0.52                 | 18.452           | 6.151         | 16.234                      | 8.978                    | 3.332              | 1.123              | 0.27        | 1.003        | 0.278       | 2.565       | 2.132     | 0           | 20.523    | MCTF        |
| 1767.2 | 1767.2    | Fine sandstone     | 7.783         | 0.037            | 24.958              | 1.54                 | 18.068           | 3.142         | 18.91                       | 5.552                    | 3.282              | 5.399              | 0.956       | 3.96         | 3.141       | 3.985       | 0          | 0           | 3.790     | ACMF        |
| C-36   | 1758      | Fine sandstone     | 11.2          | 0.079            | 24.63               | 1.5                  | 19.37            | 2.989         | 19.673                      | 9.365                    | 0.164              | 4.742              | 0.81        | 3.354        | 2.66        | 1.793       | 0          | 0           | 7.276     | ACMF        |
| 1667.2 | 1667.2    | Medium sandstone   | 8.295         | 0.016            | 34.358              | 1.67                 | 10.979           | 1.568         | 17.799                      | 6.306                    | 2.384              | 4.544              | 1.286       | 1.715        | 1.029       | 0.779       | 0          | 0.779       | 5.659     | QCDF        |
| 1672.5 | 1672.5    | Medium sandstone   | 10.546        | 0.072            | 31.851              | 1.78                 | 14.438           | 2.406         | 13.467                      | 11.255                   | 1.355              | 4.685              | 0.8         | 3.314        | 2.628       | 0.762       | 0          | 0.762       | 6.553     | QCDF        |
| 1674.5 | 1674.5    | Medium sandstone   | 10.17         | 0.172            | 24.549              | 2.129                | 17.931           | 3.164         | 18.419                      | 7.066                    | 2.59               | 3.373              | 1.405       | 3.092        | 1.499       | 0.01        | 0          | 0           | 1.916     | QCDF        |
| 1907   | 1907      | Medium sandstone   | 7.727         | 0.15             | 37.443              | 1.724                | 16.548           | 3.31         | 13.2                        | 4.263                    | 1.176              | 3.715              | 3.143       | 3.817        | 0.561       | 0.041       | 0          | 0.802       | 4.321     | QCDF        |
| 1907.6 | 1907.6    | Medium sandstone   | 8.905         | 0.08             | 27.235              | 1.613                | 22.311           | 3.718         | 12.371                      | 6.188                    | 0.736              | 3.909              | 1.818       | 2.546        | 0.818       | 0.909       | 0          | 0.152       | 3.945     | QCDF        |
| C-37   | 1660      | Fine sandstone     | 13.6          | 0.22             | 31.261              | 2.02                 | 13.525           | 2.705         | 23.118                      | 5.89                     | 1.514              | 4.6                 | 1.302       | 1.766        | 1.041       | 0.329       | 2.165     | 0           | 4.340     | QCDF        |
4.2. Pore Geometry and Size and the Proportion of Six Pore Types

Based on the observations and pore size measurements of 63,137 pores by casting thin section and FE-SEM, six types of pores were identified by genetic characteristics. By decomposing the HPMI-NMR-derived PSD, the proportion of each type was estimated based on the least squares method (Figure 4), as shown in Section 3.4.

![Figure 4](image_url)

**Figure 4.** The results of decomposing the HPMI-NMR-derived PSDs using the least squares estimator for 13 J₁ b sandstone samples.

The pores can be classified into six genetic types: (1) residual intergranular pores (RIPs), (2) feldspar dissolution pores (FDPs), (3) rock fragment dissolution pores (RFDPs), (4) clay mineral intergranular pores (CIPs), (5) intercrystalline pores of kaolinite (IPKs), and (6) matrix pores (MP). Modified by extensive compaction and cementation, the shapes of RIPs are commonly triangular or polygonal, with radii ranging from 0.885 to 80.364 μm (Figure 5a) [13]. The proportion of RIPs in the J₁ b sandstones is relatively low, ranging from 0.39% to 11.30%. The FDPs developed an irregular strip shape and are distributed along the cleavage of feldspar (Figure 5b). FDPs are usually larger than other pores (the pore radii typically range from 0.951 to 10.429 μm) with relatively good connectivity (Figure 5i). The proportion of FDPs ranged from 4.21% to 19.77%. The RFDPs are smaller than the FDPs, with pore radii ranging from 0.885 to 80.364 μm (Figure 5a). The proportion of RFDPs ranged from 4.21% to 19.77%. The CIPs and IPKs are smaller than 0.124 μm, with the proportion varying from 0.13% to 14.63% (Figure 5c). The proportions of CIPs and IPKs increase with more authigenic clay mineral precipitation and are especially influenced by kaolinites (Figure 4d,e,g,h). The radii of the CIPs predominantly range from 0.136 to 1.383 μm (Figure 4), as shown in Section 3.4.
and that of the IPKs ranges from 0.10% to 35.26%. Generally, the MPs have the smallest radii (mainly from 4 to 118 nm) but a high proportion in tight sandstones (Figure 5i,f). According to the size of pores, the RIFs, FDPs, and RFDPs were identified as macropores, whereas CIPs, IPKs, and MPs were identified as micropores in this study. In addition, micro-fractures caused by compaction and tectonic activities are also important to the seepage capability. These micro-fractures often developed through rigid minerals and surrounding pores (Figure 5b). However, there are few micro-fractures, representing only 1–2% of the pore space. The proportion and porosity of the six pore types are listed in Table 2.

**Figure 5.** The geometries and sizes of the six types of pores in the J1b tight sandstone samples: (a) residual intergranular pores (RIPs) between grains, well X1, sample 1674.5; (b) feldspar dissolution pores (FDPs) developed in K-feldspar, well X1, sample 1674.5; (c) rock fragment dissolution pores (RFDPs), well X1, sample 1627.5; (d) clay mineral intergranular pores (CIPs) occurring in a RFDP, well X1, sample 1907; (e) intercrystalline pores and intergranular pores of kaolinite (IPKs), well X1, sample 1787.2; (f) matrix with widely developed and a large number of matrix pores (MPs), well X1, sample 1714.6; (g) honeycombed intergranular pores developed among the I/S mixed layers, well X1, sample 1827.5; (h) intergranular pores of rosette chlorites, well X1, sample 1713; and (i) frequency distributions of the pore sizes of the aforementioned six pore types.
Table 2. The proportion and porosity of different pore types in the J1b samples.

| Sample | Residual Intergranular Pores (%) | Feldspar Dissolution Pores (%) | Rock Fragment Dissolution Pores (%) | Clay Mineral Intergranular Pores (%) | Kaolinite Intercrystalline Pores (%) | Matrix Pores (%) | Residual Intergranular Pores (%) | Feldspar Dissolution Pores (%) | Rock Fragment Dissolution Pores (%) | Clay Mineral Intergranular Pores (%) | Kaolinite Intercrystalline Pores (%) | Matrix Pores (%) | X_{RMS} |
|--------|----------------------------------|---------------------------------|----------------------------------|----------------------------------|----------------------------------|----------------|----------------------------------|----------------------------------|----------------------------------|----------------------------------|----------------------------------|----------------|---------|
| 1879.5 | 1.276                            | 6.285                           | 3.565                            | 22.567                           | 4.286                            | 62.022         | 0.063                            | 0.311                            | 0.177                            | 1.118                            | 2.121                            | 3.074          | 0.006   |
| 1882.3 | 3.965                            | 4.978                           | 0.872                            | 19.227                           | 4.669                            | 66.174         | 0.215                            | 0.270                            | 0.047                            | 1.043                            | 0.253                            | 3.589          | 0.005   |
| 1827.5 | 5.694                            | 4.384                           | 1.307                            | 15.086                           | 8.962                            | 64.366         | 0.247                            | 0.184                            | 0.055                            | 0.631                            | 0.375                            | 2.694          | 0.002   |
| 1714.6 | 0.392                            | 4.212                           | 1.974                            | 4.800                            | 0.100                            | 89.051         | 0.030                            | 0.327                            | 0.153                            | 0.372                            | 0.008                            | 6.903          | 0.007   |
| 1713   | 1.519                            | 6.790                           | 3.627                            | 4.197                            | 2.881                            | 89.103         | 0.107                            | 0.477                            | 0.255                            | 0.295                            | 0.202                            | 6.258          | 0.008   |
| 1787.2 | 4.175                            | 8.329                           | 0.128                            | 21.850                           | 35.261                           | 31.597         | 0.325                            | 0.648                            | 0.010                            | 1.701                            | 2.744                            | 2.459          | 0.001   |
| C-36   | 3.585                            | 7.812                           | 8.603                            | 33.130                           | 16.588                           | 32.635         | 0.402                            | 0.875                            | 0.964                            | 3.711                            | 1.858                            | 3.655          | 0.002   |
| 1667.2 | 1.007                            | 11.456                          | 4.586                            | 25.866                           | 11.431                           | 45.654         | 0.084                            | 0.950                            | 0.380                            | 2.146                            | 0.948                            | 3.787          | 0.003   |
| 1672.5 | 4.067                            | 12.689                          | 4.929                            | 29.457                           | 9.146                            | 39.712         | 0.429                            | 1.338                            | 0.520                            | 3.107                            | 0.965                            | 4.188          | 0.002   |
| 1674.5 | 5.230                            | 16.229                          | 14.632                           | 20.347                           | 15.411                           | 28.092         | 0.532                            | 1.651                            | 1.488                            | 2.069                            | 1.567                            | 2.857          | 0.005   |
| 1907   | 11.302                           | 14.879                          | 14.123                           | 18.756                           | 13.318                           | 27.576         | 0.873                            | 1.150                            | 1.091                            | 1.449                            | 1.029                            | 2.131          | 0.002   |
| 1907.6 | 3.468                            | 10.698                          | 14.238                           | 23.092                           | 18.690                           | 29.939         | 0.309                            | 0.953                            | 1.268                            | 2.056                            | 1.664                            | 2.666          | 0.004   |
| C-37   | 5.362                            | 19.778                          | 11.296                           | 30.030                           | 14.773                           | 20.750         | 0.729                            | 2.690                            | 1.536                            | 4.084                            | 2.009                            | 2.822          | 0.002   |
4.3. Pore Structures Characterized by HPMI and NMR

4.3.1. Pore Size Distribution Patterns from HPMI and NMR

The PSD patterns of the four above-mentioned lithofacies are distinctive. In the ACMF, the PSD from HPMI are continuous without obvious peak values, and the radii are distributed from 0.002 to 6.3 μm (Figure 6a). The T₂ spectrums have noticeable bimodal characteristics with greater amplitudes of the left peaks, demonstrating that micropores (MPs and CPs) control the PSD of the ACMF (Figure 6e). In the QCDF, the HPMI-derived PSD exhibit unimodal characteristics with radii ranging from 0.1 to 0.63 μm (Figure 6b). The T₂ spectrums display conspicuous bimodal behaviors, with the left peaks ranging from 0.619 to 1.822 ms and the right peaks ranging from 8.829 to 20.256 ms (Figure 6f). The CCF has an obvious bimodal peak pattern in HPMI-derived PSD, which reveals that the samples are dominated by micropores and relatively large pores ranging from 0.04 to 0.0063 μm and 0.25 to 0.4 μm, respectively (Figure 6c). The T₂ spectrums of CCF have noticeable unimodal features, suggesting that the PSD are relatively controlled by micropores (Figure 6g). In the MCTF, the PSD derived from HPMI show single-peak characteristics, with peaks distributed from 0.025 to 0.16 μm, indicating that the MCTF samples have more micropores (Figure 6d). Similarly, the T₂ spectrums of MCTF are also characterized by typical bimodal behaviors and have greater left peaks, with peak values ranging from 0.496 to 1.203 ms (Figure 6h).

![Figure 6](image_url)

Figure 6. PSD obtained from the HPMI and NMR experiments of four typical lithofacies. (a–d) PSD derived from HPMI for authigenic clay mineral facies (ACMF), quartz cemented-dissolution facies (QCDF), carbonate cemented facies (CCF), and matrix-caused tightly compacted facies (MCTF) (e–h) PSD derived from NMR for the ACMF, QCDF, CCF, and MCTF.

4.3.2. Parameters of Pore Structures Determined by NMR and HPMI

The microscopic parameters of pore networks were evaluated by HPMI and NMR. Quantitative pore structure parameters, such as entry pressure (Pₐ), maximum pore radius (rₘₐₓ), medium pore radius (r₉₀), average pore radius (r), sorting coefficient, skewness and maximum mercury intrusion saturations (Sₘₐₓ), were derived from HPMI measurements. The Pₐ ranged from 0.1 to 30.625 MPa, corresponding to an rₘₐₓ in the range of 0.024 to 5.334 μm. The r₉₀ and r of pores were 0.002–0.399 μm and 0.008–0.963 μm, respectively. rₘₐₓ, which represents the pore radius corresponding to the apex of Pittman’s plot, reveals the transition from well-connected pores to poorly connected pores [50], and was 0.027–1.090 μm. The NMR porosities of all samples are consistent with the helium porosities, verifying that the PSD determined using NMR are fully ranged and the diffusion effects can be neglected [27]. The T₂cutoff is defined as the separation between BVI and FFI, and the BVI porosity (ϕBVI) and FFI porosity (ϕFFI) were calculated. The T₂cutoff values are not constant, but vary between 1.25 and
18.64 ms (Table 2). The $T_{2\text{peak}}$ (the $T_2$ value corresponding to the highest signal amplitude) and $T_{2gm}$ (the amplitudes weighted as means on a logarithmic scale) values can be derived from the $T_2$ spectrum as well. The parameters of the pore structures identified from NMR and HPMI were determined, as shown in Table 3.

### 4.4. Fractal Dimensions from the Combination of HPMI and NMR

The plots of $\log S_v$ vs. $\log r$ of samples in accordance with Equations (8)–(14) were used to calculate the fractal dimensions of the pore networks based on the HPMI-NMR-integrated PSD [23,27]. Two distinct linear segments were identified, and the values of radii that correspond to the division points ($r_d$) were similar to the values of $r_{\text{ape}}$, which is regarded as the boundary dividing poorly-connected pores and well-connected pores [11]. The proportion of pores with radii larger than $r_d$ has a positive correlation with the proportion of macropores (Figure 7a). Similarly, a positive linear correlation exists between the proportion of pores whose sizes are smaller than $r_d$ and the proportion of micropores (Figure 7a).

![Figure 7. Plots exhibiting the relationships between (a) the proportion of different pore types and their fractal dimensions, and (b) $D_1$ and $D_2$ of different lithofacies.](image)

Therefore, the fractal dimension $D_1$ derived from segments with radii smaller than $r_d$ represents the fractal characteristics of MPs and CPs. The fractal dimension $D_2$ calculated from segments with radii larger than $r_d$ represents the heterogeneities of RIPs and DPs. The values of $D_2$ are generally larger than those of $D_1$, and there is a strongly positive correlation between $D_1$ and $D_2$ (Figure 7b). The $D_1$ values range from 0.719 to 2.240, and the $D_2$ values vary from 2.840 to 2.994. Furthermore, the fractal dimensions of the four lithofacies are distinct (Figure 7b). The $D_1$ and $D_2$ values of the MCTF are highest among all lithofacies. The fractal dimensions of the CCF are slightly smaller than those of the other samples (Figure 8), which means that the presence of a large number of CPs increases the heterogeneity of macropores. The characteristics of the fractal dimensions are listed in Table 4.
Table 3. The parameters of pore structure in J1b tight sandstones from NMR and HPMI.

| Sample | Lithofacies | Parameters of HPMI Measurement | Parameters of NMR Measurement |
|--------|-------------|--------------------------------|--------------------------------|
|        |             | $P_d$ (MPa) | $r_{eq}$ (µm) | $r_{apex}$ (µm) | $\phi_{NMR}$ (%) | $T_{2cutoff}$ (ms) | $\phi_{BVI}$ (%) | $\phi_{FEI}$ (%) | $T_{2peak}$ (ms) | $T_{2gm}$ (ms) |
| 1879.5 | CCF         | 30.625      | 0.002          | 0.008          | 1.324           | 0.212             | 3.074            | 30.625           | 0.267          | 4.920           | 3.122           | 2.499           | 0.508           | 1.077           | 21.994         |
| 1882.3 | CCF         | 13.773      | 0.005          | 0.015          | 0.881           | 0.253             | 3.589            | 13.773           | 0.358          | 5.320           | 4.702           | 3.765           | 0.765           | 0.554           | 10.201         |
| 1827.5 | CCF         | 2.052       | 0.010          | 0.064          | 2.209           | 0.375             | 2.694            | 2.052            | 1.090          | 4.150           | 1.250           | 3.223           | 0.655           | 0.469           | 6.496          |
| 1714.6 | MCTF        | 2.753       | 0.062          | 0.083          | 1.974           | 0.008             | 6.903            | 2.753            | 0.036          | 7.468           | 3.917           | 4.044           | 0.822           | 1.138           | 4.835          |
| 1713  | MCTF        | 1.370       | 0.031          | 0.166          | 2.661           | 0.202             | 6.288            | 1.370            | 0.027          | 6.980           | 3.752           | 4.159           | 0.845           | 1.023           | 4.325          |
| 1787.2 | ACMF        | 0.675       | 0.155          | 0.208          | 2.125           | 2.744             | 2.459            | 0.675            | 1.078          | 7.684           | 14.650          | 4.537           | 0.922           | 0.397           | 6.207          |
| C-36   | ACMF        | 0.677       | 0.082          | 0.209          | 2.634           | 1.858             | 3.655            | 0.677            | 0.540          | 12.213          | 17.158          | 3.916           | 0.796           | 6.693           | 15.499         |
| 1667.2 | QCDF        | 0.672       | 0.027          | 0.220          | 2.832           | 0.948             | 3.787            | 0.672            | 0.134          | 8.162           | 11.895          | 3.677           | 0.747           | 1.677           | 41.876         |
| 1672.5 | QCDF        | 0.150       | 0.200          | 0.230          | 2.468           | 0.965             | 4.188            | 0.150            | 0.357          | 9.987           | 11.098          | 3.492           | 0.710           | 8.829           | 19.256         |
| 1674.5 | QCDF        | 0.138       | 0.399          | 0.330          | 3.444           | 1.567             | 2.857            | 0.138            | 0.542          | 10.050          | 16.832          | 3.379           | 0.687           | 18.644          | 27.054         |
| 1907   | QCDF        | 0.674       | 0.222          | 0.298          | 2.222           | 1.029             | 2.131            | 0.674            | 1.081          | 10.089          | 14.326          | 3.255           | 0.662           | 8.588           | 43.670         |
| 1907.6 | QCDF        | 0.100       | 0.220          | 0.629          | 3.000           | 1.664             | 2.666            | 0.100            | 0.359          | 6.634           | 16.058          | 3.624           | 0.737           | 1.724           | 22.075         |
| C-37   | QCDF        | 0.138       | 0.243          | 0.963          | 3.460           | 2.009             | 2.822            | 0.138            | 0.268          | 12.943          | 18.644          | 3.217           | 0.654           | 14.940          | 31.250         |
Figure 8. Fractal dimension analysis from NMR-HPMI derived PSD of four selected representative sandstone samples for the (a) QCDF, (b) ACMF, (c) CCF, and (d) MCTF.

Table 4. The characteristics of fractal dimensions in the J1b sandstone samples derived from NMR-HPMI-integrated curves.

| Sample | Lithofacies | Proportion of $D_1$ (%) | $K_1$ | $D_1$ | $R^2_{D1}$ | Proportion of $D_2$ (%) | $K_2$ | $D_2$ | $R^2_{D2}$ | $r_d$ |
|--------|-------------|--------------------------|-------|-------|------------|--------------------------|-------|-------|------------|-------|
| 1879.5 | CCF         | 78.950                   | 1.138 | 1.862 | 0.705      | 21.050                   | 0.051 | 2.950 | 0.871      | 0.268 |
| 1882.3 | CCF         | 91.230                   | 1.245 | 1.755 | 0.790      | 8.770                    | 0.018 | 2.982 | 0.843      | 1.079 |
| 1827.5 | CCF         | 88.800                   | 1.201 | 1.799 | 0.718      | 11.200                   | 0.016 | 2.984 | 0.825      | 1.106 |
| 1714.6 | MCTF        | 89.650                   | 0.886 | 2.115 | 0.782      | 10.350                   | 0.022 | 2.978 | 0.985      | 0.035 |
| 1713  | MCTF        | 92.694                   | 0.760 | 2.240 | 0.705      | 7.306                    | 0.006 | 2.994 | 0.736      | 0.027 |
| 1787.2 | ACMF        | 86.730                   | 1.738 | 1.262 | 0.740      | 13.270                   | 0.026 | 2.974 | 0.876      | 1.079 |
| C-36  | ACMF        | 78.228                   | 1.866 | 1.134 | 0.755      | 21.772                   | 0.058 | 2.942 | 0.822      | 0.532 |
| 1667.2 | QCDF        | 62.580                   | 1.973 | 1.027 | 0.777      | 37.420                   | 0.043 | 2.957 | 0.780      | 0.134 |
| 1672.5 | QCDF        | 70.980                   | 1.472 | 1.528 | 0.740      | 29.020                   | 0.029 | 2.971 | 0.718      | 0.362 |
| 1674.5 | QCDF        | 65.720                   | 1.856 | 1.144 | 0.723      | 34.280                   | 0.115 | 2.885 | 0.905      | 0.542 |
| 1907  | QCDF        | 71.900                   | 1.404 | 1.596 | 0.739      | 28.100                   | 0.033 | 2.968 | 0.839      | 1.100 |
| 1907.6 | QCDF        | 66.980                   | 1.918 | 1.082 | 0.761      | 33.020                   | 0.080 | 2.920 | 0.836      | 0.363 |
| C-37  | QCDF        | 49.143                   | 2.281 | 0.719 | 0.798      | 50.857                   | 0.160 | 2.840 | 0.905      | 0.268 |

5. Discussion

5.1. Validation and Limitation of Decomposing the NMR-HPMI Integrated PSD by the Least Squares Estimator

After decomposing the NMR-HPMI-integrated PSD by the least squares estimator mentioned in Section 3.4, the results show the reliability of this method through highly positive correlations between the mineral contents and the porosities of relevant pores: the porosity of MP exhibits a positive correlation with the content of matrix ($R^2 = 0.8821$, Figure 9a), and a direct correlation was discovered between the content of kaolinite and the porosity of IPK ($R^2 = 0.7310$, Figure 9b). There is also a significant proportionality relationship between the content of clay minerals and the porosity of CIP ($R^2 = 0.8084$, Figure 9c).

The accuracy of the proportion of pores can be indirectly evaluated by calculating the difference between the reconstructed PSD and the HPMI-NMR derived PSD. The root mean square error of reconstruction ($X_{RMS}$) can be calculated by,
where \( y_i(r_i) \) is the pore volume fraction from the HPMI-NMR derived PSD corresponding to the \( i \)th pore radius and \( y_c(r_i) \) is the pore volume fraction from the reconstruction PSD corresponding to the \( i \)th pore radius. \( M \) is the number of the pore radius.

The RMS errors of 13 samples ranged from 0.001 to 0.008 (Table 2), which suggests that the differences between the reconstructed PSD and NMR-HPMI derived PSD are clear, proving that the results could be employed to determine the porosity contributions of pore types from different genetic origins.

However, many flaws in this method cannot be neglected. It is necessary to indicate that self-defects of HPMI would cause the cumulative pore volume fraction of HPMI-derived PSD to be somewhat not consistent with that of NMR-derived PSD. For instance, the pore-blocking effects might mean that the macropores cannot be fully detected [6]. However, compared to the RCP and \( \text{N}_2 \) adsorption results, the HPMI can characterize a wider ranges of pore sizes (from several nm to hundreds of \( \mu \)m). Hence, the use of HPMI-NMR derived PSD is the best choice for multi-scale pore networks so far.

In addition, the porosity contributions of pores with unfixed sizes (e.g., moldic pores and micro-fractures) cannot be accurately estimated by the least squares estimator. The porosities of these pores could be temporarily ignored because they are rarely observed via thin sections or SEM in the \( J_1b \) sandstones. The above discussion indicates that decomposing the NMR-HPMI-integrated PSD by the least squares estimator is effective for determining the pore volume fractions of different genetic pore types in \( J_1b \) tight sandstones.

\[
X_{\text{RMS}} = \sqrt{\frac{\sum_{i=1}^{M} (y_i(r_i) - y_c(r_i))^2}{M}},
\]  

(15)

**Figure 9.** The correlation between the porosities of different types of pores and mineral compositions: (a) matrix pore (MP) porosity vs. matrix content, (b) intercrystalline pores of kaolinite (IPK) porosity vs. kaolinite content, (c) CIP porosity vs. clay minerals content, (d) MP porosity vs. residual intergranular pore (RIP) porosity, (e) the total porosity vs. carbonate cement content, (f) DP porosity vs. quartz overgrowth content; (g) DP porosity vs. clay-related pore (CP) porosity, and (h) RIP porosity vs. quartz overgrowth content.
5.2. Effects of Sedimentary and Diagenetic Settings on Petrophysical Properties and Pore Networks

5.2.1. Impact of Diagenesis and Sedimentary Processes on the Macroscopic Reservoir Quality

The sedimentary conditions determine the original reservoir quality by controlling the sediment composition, grain size, and primary porosity. In the sedimentary setting of the proximal-shallow delta plain, sediments accumulated quickly, leading to the poor sorting and small grain size of the sandstones, while generating a large number of matrix at the bottom of the braided channel. Hence, a large number of MPs exist in MCTF, and the highest MP porosity in the MCTF is 6.903%. Most MPs are on the nanometer scale, and their origins are currently being debated. MPs may include the tiny intergranular pores between matrix grains, or the DPs formed by eogenetic dissolution [52,53].

The high MP content resulted in a poor connection between the porosity-permeability and complicated pore network structures. In addition, the high matrix content not only aggravates damage to the reservoirs due to mechanical compaction [52], but also triggers a sharp reduction in the RIP porosity (Figure 9d).

In the burial process, the diagenetic reworking determines the reservoir quality, and the pore types of the four diagenetic facies are different. The CCF is mostly distributed at the interfaces between mudstones and sandstones or the thin sandstone interlayers of massive mudstones (Figure 10a). In the process of pressure solution or under the reworking of acidic fluids, matrix, frame grains, or adjacent mud layers may provide abundant Ca\(^{2+}\) and Fe\(^{2+}\) for the cementation of carbonates. In addition, the organic acid dissolved a large number of aluminosilicate minerals, whereas large-scale DPs are rarely discovered in the early calcite cement (Figure 3e–h) because, in a closed diagenesis system, the equilibrium constant of the carbonate leaching reaction is much lower than that of the feldspar (or rock fragments) dissolution reaction. Additionally, more H\(^+\) is needed by the reaction of carbonate cement dissolution [54]. The cementation of calcite and siderites in the eogenetic period considerably blocked the RIP, and ferrocalcite partially replaced the feldspars or filled some DPs during the mesogenetic period (Figure 9e). In summary, the carbonate cements decreased the proportion of macropores, worsening the petrophysical properties of the reservoirs.

The QCDF mostly developed in the center of the channel sand bodies, which are favorable for the modification and migration of acid [55]. The positive correlation between the quartz overgrowth content and the DP or CP porosity indicates that the Si\(^4+\) in the quartz overgrowth mainly originated from the dissolution of feldspar and rock fragments, especially from the feldspar, due to the higher correlation coefficient between the quartz overgrowth content and the FDP porosity (Figure 9f,g). However, samples with higher matrix contents do not conform to this correlation (Figure 9f), which reveals that the matrix hindered the activity of the diagenetic fluids and even inhibited the cementation of quartz. The mesogenetic quartz overgrowth increased the compression resistance of reservoirs protecting the RIPs from being destroyed by compaction (Figure 9h). In the QCDF, DPs play important roles, constituting 20–40% the macropores. However, the porosity of most of the QCDF is still below 10% (Figure 10a,b), which demonstrated that dissolution products (e.g., authigenic clay minerals and quartz cements) moved slowly in the tortuous aqueous pathways in the closed diagenetic environment by diffusion or deposited in situ and further blocked the pores [14,52]. As a result, the reworking degree of dissolution on the storage spaces in J1b sandstones is extremely limited. This finding is proven by the positive correlation between the CP and DP porosities (Figure 9g).

In the ACMF, CPs play dominant roles, with proportions ranging from 4.445% to 5.568%. The continuous reduction in macropores resulted from mat-like, bridge-like, and fibrous illite, and vermicular or booklet kaolinite aggregates filling the pore spaces (Figure 4e,g,h), and a series of nanoscale pores with poor seepage performances were generated by the authigenic clay minerals [11]. The authigenic clay minerals mainly derived from feldspars and rock fragments due to dissolution by the organic acids and meteoric water. However, the positive correlation between the CP and DP porosities is not observed in the ACMF (Figure 9g), which implies that authigenic clay minerals may...
be generated by dissolution in addition to other reactions. For instance, illite may be converted from kaolinite during the eogenetic period, and chlorite may be converted from berthierine or odinite [56].

![Figure 10](image-url)

**Figure 10.** Impacts of the proportion distributions of different pore types in the four lithofacies. (a) Pore volume factions of six types of pores in 13 samples; (b) the variation in porosity, (c) the variation in permeability, (d) the variation in the proportion of immovable fluid (BVI) for 13 samples; and (e) pore network model of four lithofacies.

5.2.2. Relationship between Petrophysical Properties and Different Genetic Pores

The pore volume fraction of different genetic pores plays the bridge and medium roles in linking the sedimentary-diagenetic factors and microscopic pore structures from the perspective of storage and percolation capacities, the porosity of the QCDF is only slightly higher than that of the other lithofacies, but its permeability is higher than that of the other lithofacies by one order of magnitude (Figure 10b,c), which indicates that the increase in the DP volume is favorable for the increase in percolation pathways, considerably improving the permeability. The porosity of the CCF is the lowest among the four lithofacies, but the permeability is slightly higher than that of the MCTF samples and some of the ACMF samples (Figure 10b,c). The porosities of the MCTF and ACMF are slightly lower than that of the QCDF, although the porosity is higher than 10% in the ACMF, the permeabilities of both the MCTF and ACMF are extremely low, lower than that of the CCF, which has the lowest porosity (Figure 10b,c). MPs and CPs constitute some of the porosity, but these micropores are mostly isolated with poor connectivity at the nanoscale, causing the permeabilities of the reservoirs to be fairly low. The φBVI values of the ACMF and MCTF are significantly higher than those of the QCDF and CCF, which also proves that most MPs and CPs are isolated pores (Figure 10d). The porosity of the ACMF is slightly higher than that of the MCTF, which indicates that pore-filling authigenic clay minerals decreased damage due to compaction and thus preserved the reservoir quality to some extent [11] (Figure 10d,e).

From the perspective of porosity, different types of pores provide certain contributions to the volumes of storage spaces in sandstones. Among them, MPs and CPs constitute the majority of the
total porosity in $J_1 b$ tight sandstones (Figure 10a). However, the porosities of samples might increase as the proportions of FDPs and CIPs increase but decrease as the proportion of MPs increases (Figure 11).

![Figure 11. The relationship between the petrophysical properties and the proportions of different pore types. (a–f) Porosity vs. the proportions of RIP, FDP, RFDP, CIP, IPK, and MP; (g–l) permeability vs. the proportions of RIP, FDP, RFDP, CIP, IPK, and MP.](image)

Effective percolation pathways have an important effect on permeability in tight sandstones. From the relationship identified between the permeability and the proportions of different types of pores in tight sandstones indicates that permeability commonly increased as RIP and DP porosities increased (Figure 12g–i). In addition, there is no correlation between permeability and CP porosity, and permeability even presents a decreasing trend with the increase in MP porosity (Figure 11j–l).
The contribution of different pores to the permeability ($K_i$) can be obtained by considering the bundle of the tube model [57]:

$$K_i = \frac{dS_{hgi} \times r^2}{\sum_i (dS_{hgi} \times r_i)}$$

where $dS_{hgi}$ is the increment of total mercury intrusion corresponding to pores with a radius of $r_i$ [18].

The permeability contribution by HPMI is determined on the basis of the Purcell equation. In the QCDF, 31.688% of the pores control 95% to permeability, and the types of the pores that contribute significantly to the permeability are mainly RIPs and DP s (Figure 12a). In the ACMF, 32.256% pores contribute 95% to permeability, and similarly, RIPs and DPs contribute greatly to the permeability (Figure 12b). For the CCF, the pores that contribute considerably to permeability range from 0.177 to 0.63 μm and account for 42.331% of the total pore volume (Figure 12c). We found that the permeability of the CCF is mainly controlled by CIPs, RFDPs, and CIPs. In the MCTF, 54.483% of the pores control 95% of the permeability, of which 92.097% is controlled by the MP s and IPKs with radii of 0.015–0.1 μm, and the rest (2.993%) is controlled by the MP s, which are smaller than 0.015 μm (Figure 12d). As the proportion of pores that mainly contribute to the permeability increased gradually, the main types of permeability-contributing pores transitioned from macropores to micropores, and the permeability decreased gradually (Figure 12).

To summarize, macropores are better connected and strongly contributed to permeability, possibly due to the formation of effective percolation pathways in the tight sandstones. However, a large amount of immovable fluid exists in the micropores, suggesting that the permeability contributions of micropores are limited, and the higher proportion of micropores, the lower the permeability [44]. Therefore, although micropores could provide considerable storage spaces and slightly increase the
total porosity, the percolation capacity of the J1b sandstones is still poor due to the poor connectivity among these pores.

5.3. Relationships Among the Fractal Dimensions, Petrophysical Properties, and Pore Structures of Four Lithofacies

Previously, many scholars thought that a low fractal dimension represents better seepage and storage capacities, which correspond to a higher proportion of primary pores and weaker diagenetic modification [58]. However, pore networks are often complicated due to multiple fractal characteristics, and tight sandstone is no exception. This study found that the total porosity is negatively correlated with fractal dimensions $D_1$ and $D_2$, whereas the $D_2$ is generally higher than $D_1$ because the proportion of micropores is very high (Figures 13 and 14a). As the RIP porosity increases, $D_1$ and $D_2$ obviously decrease, as does RFDP porosity (Figure 13a,c). The FDP porosity has an inverse relationship with $D_2$, and its relationship with $D_1$ displayed no obvious trend (Figure 13b). In terms of the correlative degree, the porosities of different macropores have more effects on $D_2$ than on $D_1$, and the CP porosity has more effects on the heterogeneity of micropores than that of macropores (Figure 13d,e). The MP porosity is positively related to $D_1$ and $D_2$ (Figure 14f), indicating that the high proportion of MPs is the main reason for the complexity of pore networks in tight sandstones.

Figure 13. Relationships between fractal dimensions and porosities of different pore types. (a) porosity of RIP vs. $D_1$ and $D_2$, (b) porosity of FDP vs. $D_1$ and $D_2$, (c) porosity of RFDP vs. $D_1$ and $D_2$, (d) porosity of CIP vs. $D_1$ and $D_2$, (e) porosity of IPK vs. $D_1$ and $D_2$, and (f) porosity of MP vs. $D_1$ and $D_2$.

Figure 14. Relationships between the fractal dimensions and petrophysical properties. (a) Total porosity vs. $D_1$ and $D_2$; (b) total permeability vs. $D_1$ and $D_2$.

Permeability is negatively correlated with $D_2$, and the relationship between permeability and $D_1$ is not apparent (Figure 14a). The complexity of macropore networks may dominate reservoir permeability whereas the micropores heterogeneity has less of an effect on permeability (Figure 14b).

The pore sizes have a direct effect on the fractal dimension, and the heterogeneity of pore networks determines the percolation capacities of tight sandstones. The maximum and median pore radii can effectively describe the complexity of micropores, whereas the influence of pore sizes on the
heterogeneity of macropores is not obvious (Figure 15a,b). In addition, the heterogeneity of micropores decreases considerably with the increase in $\phi$BVI (Figure 15c). Similarly, there is a strongly negative correlation between $\phi$FFI and $D_2$ (Figure 15d). Therefore, in the process of hydrocarbon charging, oil and gas tended to flow into large pores that have regular shapes with smooth surfaces, especially RIPs and DPs. In addition, $D_1$ and $D_2$ can be effective parameters for evaluating the percolation characteristics of tight sandstone reservoirs.

**Figure 15.** Relationships between the fractal dimensions and pore structure parameters. (a) Pore radius (maximum radius, median radius, and average radius) vs. $D_1$; (b) pore radius (maximum radius, median radius, and average radius) vs. $D_2$; and (c) $D_1$ vs. $\phi$BVI (d) $D_2$ vs. porosity of movable fluid (FFI).

6. Conclusions

The effects of depositional and diagenetic settings on the microscopic pore networks and macroscopic petrophysical properties of tight sandstones from the Lower Jurassic Badaowan Formation ($J_1b$) in the Southern Junggar Basin were investigated in this study. The conclusions are as follows:

1. A high matrix content, strong carbonate cementation, high authigenic clay mineral content, and extensive dissolution are primary reasons for the heterogeneities of the pore networks in the $J_1b$ sandstones. Through casting thin sections observation and FE-SEM, six types of pores were identified: residual intergranular pores (RIPs), feldspar dissolution pores (FDPs), rock fragment dissolution pores (RFDPs), clay mineral intergranular pores (CIPs), kaolinite intercrystalline pores (IPKs), and matrix pores (MPs). The pore volume fractions of six genetic pore types were determined according to decomposing the integrated PSD from nuclear magnetic resonance (NMR) and high-pressure mercury injection (HPMI). Four lithofacies were determined based on the analysis of the mineral compositions, pore structures, and sedimentary-diagenetic processes: quartz cemented-dissolution facies (QCDF), carbonate cemented facies (CCF), authigenic clay minerals facies (ACMF), and matrix caused tightly compacted facies (MCTF).

2. Due to the limited modification caused by dissolution, the QCDF has a slightly higher porosity but much higher permeability compared to those of the other lithofacies. A slight drop in pore volumes and a considerable reduction in permeability occur as the proportion of MP and CP increases in the MCTF and ACMF. Carbonate cementation decreased the porosity of CCF, although the permeability of CCF is higher than those of the MCTF and ACMF. This difference is because the storage spaces in the $J_1b$ sandstones are mainly determined by a large number of CPs and MPs, while the percolation...
capacity is mainly dominated by RIPs and DPs. However, the contributions of MPs and CPs are limited by their smaller pore sizes and complex pore structures.

(3) The pore networks of tight sandstones in J1b show multiple fractal characteristics, and the fractal dimensions of micropores (MPs and CPs) and macropores (RIPs and DPs) are defined as D1 and D2, respectively. The macropore porosities significantly influence D2, whereas D1 was more prominently affected by the proportion of micropores. The high proportion of MP is the main reason for the complexity of the entire pore network. The heterogeneity of macropores chiefly controlled the flow capabilities of the tight sandstones in J1b. Besides, larger RIPs and DPs with regular shapes, and smooth surfaces provide more effective spaces for oil and gas accumulation compared to those provided by the sandstones enriched in MPs and CPs.

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Appendix A

Figure A1. The clustering heatmap of petrophysical properties and mineral contents which is employed to choose the representative samples of four lithofacies for characterizing pore structures of the tight sandstones in J1b.

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