Applying NMR T2 Spectral Parameters in Pore Structure Evaluation—An Example from an Eocene Low-Permeability Sandstone Reservoir

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Abstract: The Eocene low-permeability sandstone reservoirs in the Dongying Depression, Bohai Bay Basin, China host a significant amount of oil reserves. The development of the reservoirs has been hampered by our inability to understand the complex and heterogeneous pore structures of the reservoirs. In this study, the pore systems, pore sizes, pore connectivity, and movable fluid distribution of the Eocene Shahejie Formation (Es4) sandstone reservoirs were investigated using an integrated analysis of optical and scanning electron microscopy (SEM), mercury injection capillary pressure (MICP), and nuclear magnetic resonance (NMR). The full-range pore structures of the Es4 sandstone reservoirs were evaluated by using NMR experiments. Various NMR T2 spectral parameters suitable for describing the pore structures and movable fluid distribution were extracted through morphological and statistical analysis of NMR T2 spectra. In combination with corresponding MICP data and petrophysical properties, we have demonstrated the reliability and robustness of the T2 spectral parameters for pore structure characterization. Four types of pore structures (I, II, III, and IV) were distinguished from the NMR T2 spectral parameters in association with other petrophysical properties and macroscopic behaviors. We have demonstrated the effectiveness of using the NMR T2 spectral parameters to characterize and classify micropore structures, which may be applied to effectively evaluate and predict low-permeability reservoir quality.

Keywords: NMR T2 spectra; pore structure; low-permeability sandstones; Dongying Depression

1. Introduction

The Eocene low-permeability sandstone reservoir is a major petroleum source in the Dongying Depression, Bohai Bay Basin, China [1–3]. The reservoirs are characterized by poor petrophysical properties, complex pore structures, and strong reservoir heterogeneities owing to their terrestrial depositional environments and complex diagenetic modifications. Detailed and integrated analyses of pore structures are crucial for reservoir quality evaluation [4–7], permeability prediction [8–10], and identification of reservoir formation mechanisms [11,12]. Pore structures are defined as the geometric shape, type, size, distribution, and connectivity of pore throats, as well as the relationships among various properties [13,14]. The complex pore systems, highly variable pore size distribution, and poor connectivity in the Eocene sandstone reservoirs pose a great challenge in the adequate characterization of their microscopic pore structures.

Various analytical methods have been applied to investigate the pore structures of sandstone reservoirs, including optical petrography [15–17], SEM [18,19], MICP [20–22], X-ray computer tomography [23–25], nitrogen gas adsorption [26,27], and NMR [28,29].
NMR, as a non-invasive technique, is widely used in pore structure characterization and movable fluid evaluation [30–34]. The NMR technique has also been successfully applied in other fields, such as CO2 storage and geological modeling [35,36].

Previous studies mainly invoked indirect analysis of NMR data, including qualitative characterization of pore size distribution [30,37], simulation of capillary pressure curves [38,39], and estimation of movable fluid distribution in pore space [40,41]. Several researchers also paid attention to analyzing some sensitive NMR parameters for pore structure characterization and evaluation (e.g., NMR porosity, $T_2$ geometric mean value ($T_{2gm}$), $T_2$ cut-off time ($T_{2cut0}$), maximum $T_2$ relaxation time ($T_{2max}$), porosity for effective movable fluids, and pore components ($S_i$, $S_2$, and $S_3$) [42,43]. We had reported the effectiveness of fractal analysis and machine learning on pore structure characterization [3]. In this paper, we attempt to shed light on the application of the NMR $T_2$ spectral parameters in pore structure evaluation. Different from the previous study, to the focus is on the morphological analysis of NMR $T_2$ spectra. From the perspective of pore geometry, NMR $T_2$ spectra show similar morphological characteristics with the pore size distribution derived from MICP measurements. Hence, the direct extraction of quantitative NMR parameters based on mathematical morphology analysis of NMR $T_2$ spectra would be more practical. We also try to verify the feasibility of using the NMR $T_2$ spectral parameters to derive pore structure information by correlating the NMR $T_2$ spectral parameters, petrophysical parameters, and capillary parameters. NMR spectral parameters can also be potentially applied to evaluate pore structures and further extend the NMR logging capability.

In this study, several technical methods were combined to quantify pore structure features in low-permeability sandstone reservoirs. We attempted to directly extract NMR $T_2$ spectral parameters from the morphological and statistical analysis of NMR data. We also hoped to shed light on pore structure identification and evaluation using extracted NMR $T_2$ spectral parameters in combination with other experimental data. In this paper, the first section describes the significance, aims, and scopes of this study. The second section presents the geological background, sampling information, and methodology; The third section investigated the petrophysical properties, pore structures, and effective movable fluid in pore space using an integrated method. The final section discusses the effectiveness of the NMR $T_2$ spectral parameters in pore structure evaluation by establishing a reservoir quality classification scheme for the Eocene sandstones.

2. Geological Background

The Bohai Bay Basin is an important petroliferous basin in eastern China (Figure 1A) [2,39]. The Dongying Depression, a secondary tectonic unit in the Bohai Bay Basin (Figure 1B,C), experienced both synrift and postrift tectonism (Figure A1) [44,45]. The Eocene Shahejie Formation (Es) is the main regional reservoir containing four units, including Es4, Es3, Es2, and Es1 from bottom to top. The upper Es4 (Es4u) member is the target reservoir interval in the Dongying Depression, which is characterized by low-permeability sandstones deposited in near shore-shallow beach-bar environments (Figure A1) [1]. The sandstone reservoirs primarily comprise fine sandstones, siltstones, and argillaceous siltstones with interbedded thin mudstone layers. The Es4u sandstone reservoir is widely distributed and contains abundant hydrocarbons. However, the reservoirs are characterized by poor petrophysical properties and a highly variable pore size distribution from nano-scale to micro-scale. Optical petrography, SEM, MICP, and NMR analyses were conducted to probe the pore structures of the Es4u reservoirs aiming to better characterize and evaluate the reservoirs.
Figure 1. (A–C) Geological location of the study area in the Dongying Depression, Bohai Bay Basin, China.

3. Sampling and Methodology

3.1. Samples and Analytical Techniques

A total of 753 sandstone samples from the Eocene sandstone reservoirs were analyzed in the laboratory of China University of Petroleum (East China). The samples were first cleaned with petroleum ether for removing the oil and then dried for 24 h under a temperature of 95 °C. Core plug samples (50 mm long and 25.4 mm in diameter) were drilled for helium porosity, air permeability, MICP, and NMR measurements. Core chips were used to make thin sections for optical microscopic analysis and SEM analyses. The sample preparation procedure conforms to the protocol of GB/T23561.1-2009 “Methods for Determining the Physical and Mechanical Properties of Coal and Rock”. The experimental procedure and workflow for pore structure evaluation are shown in Figure 2.

Helium porosity and air permeability measurements were conducted on 753 core plug samples at a net confining pressure of 400 psi. Optical petrographic analysis was conducted on 327 thin sections with 500 point-counting per sample to identify pore throats and petrological characteristics of the reservoir sandstones. SEM analysis was performed on 103 samples to identify pore throat types, sizes, and contact relationships between the pore throat and clay minerals. The pore structures and pore throat size distribution of 23 core plug samples were analyzed by MICP. The maximum mercury inlet pressure is 116 MPa, corresponding to a minimum throat radius of 0.0063 μm.

NMR T₂ spectra of 21 core plug samples were measured under 100% water-saturated and centrifuged states. The samples were saturated with sodium chloride solution with a salinity of 12,000 mg/L. The experimental temperature and humidity used are 25 °C and...
50%, respectively. Firstly, the samples were saturated for 24 h with sodium chloride solution under a net pressure of 30 MPa. Then, NMR $T_2$ spectra under a water-saturated state were extracted. The echo interval, waiting time, and the number of echoes were set to 0.21 ms, 6000 ms, and 2048, respectively. The samples were centrifuged at 6000 r/min to remove free water in the core plugs, and then, they were measured again to obtain NMR $T_2$ spectra.

![Workflow](image)

**Figure 2.** Workflow used for pore structure evaluation.

### 3.2. MICP Methodologies

In the MICP measurement, an external pressure is required to drive mercury into the pore space and to obtain the pore throat volumes. The relationship between the injection pressure and pore throat radius is described by the Washburn equation (Equation (1)) under the assumption that pores are cylindrical [46]. It should be mentioned that MICP measures only pore throat sizes.

$$P_c = \frac{2\gamma \cos \theta}{r}$$  

where $P_c$ is the threshold capillary pressure (MPa); $r$ is the pore throat radius ($\mu$m); $\gamma$ is the surface tension (mN/m); and $\theta$ is the contact angle (°).

### 3.3. NMR Methodologies

#### 3.3.1. NMR Measurement

The transverse relaxation time $T_2$ can be expressed as the following [47]:

$$\frac{1}{T_2} = \frac{1}{T_{2B}} + \frac{1}{T_{2D}} + \frac{1}{T_{2S}} \approx \frac{1}{T_{2S}} = \rho \frac{S}{V}$$  

where $T_{2B}$, $T_{2D}$, and $T_{2S}$ are the bulk, diffusion, and surface transversal relaxation time in ms, respectively; $S/V$ is the surface-to-volume ratio; and $\rho$ is the transversal surface relaxivity ($\mu$m/s) [48]. Since rapid diffusion is dominated by surface relaxation in most geological media, the $T_2$ time of pore space is directly related to $S/V$ (Equation (3)).

$$\frac{1}{T_2} \approx \rho \frac{S}{V} = \rho \frac{N}{r}$$  

where $N$ is the pore shape factor ($N = 2$ for cylindrical model and $N = 3$ for spherical model) [49]. Generally speaking, short $T_2$ relaxation times are associated with small pores,
whereas long $T_2$ relaxation times correspond to large pores and fractures. Thus, the pore sizes can be characterized by $T_2$ relaxation times.

3.3.2. NMR $T_2$ Spectral Parameters

NMR $T_2$ spectra contain essential information on the petrophysical properties, pore size distribution, and fluid occurrence states. Therefore, NMR $T_2$ spectra are vital for pore structure evaluation [50,51]. In addition to the Free Fluid Index (FFI), Bulk Volume of Immovable Fluid (BVI), NMR porosity, and $T_{2\text{cutoff}}$, a number of quantitative parameters can be extracted from $T_2$ spectral analysis, including $T_{2\text{gm}}$, $T_2$ arithmetic mean value ($T_{2\text{ave}}$), $T_{2\text{max}}$, median $T_2$ relaxation time ($T_{2\text{mid}}$), sorting coefficient ($\sigma_{\text{NMR}}$), and skewness ($S_{\text{kp}}$) [41,43]. Among them, $T_{2\text{max}}$ is associated with the NMR response corresponding to the maximum pore size. $T_{2\text{mid}}$ is defined as the $T_2$ relaxation time corresponding to 50% of the total NMR porosity under a 100% water-saturated state. It is a vital parameter for pore size evaluation. $T_{2\text{peak}}$ is the $T_2$ relaxation time associated with the highest peak of the NMR $T_2$ spectra. $\varphi_{\text{max}}$ is the highest interval porosity, which is indicative of high content of pore fluid and porosity contribution. The graphical representations of various quantitative parameters in an NMR $T_2$ spectrum are shown in Figure A2.

$T_{2\text{gm}}$ and $T_{2\text{ave}}$ can be used to characterize the average $T_2$ relaxation time [52]. The calculation equations are shown in Equations (4) and (5).

$$T_{2\text{gm}} = \left( \prod_{i=1}^{N} T_{2i} \varphi_i \right)^{1/N} \varphi_{\text{nr}}$$ \hspace{1cm} (4)

$$T_{2\text{ave}} = \frac{\sum_{i=1}^{N} T_{2i} \varphi_i}{\varphi_{\text{nr}}} \varphi_{\text{nr}}$$ \hspace{1cm} (5)

The sorting coefficient ($\sigma_{\text{NMR}}$) and skewness ($S_{\text{kp}}$) can also be derived from the morphological analysis of NMR $T_2$ spectra. Among them, $\sigma_{\text{NMR}}$ describes the dispersion degree of the $T_2$ relaxation time centered on $T_{2\text{ave}}$ (Equation (6)). A small sorting coefficient indicates a uniformity distribution of the $T_2$ relaxation time.

$$\sigma_{\text{NMR}} = \sqrt{\frac{\sum (T_{2i} - T_{2\text{ave}})^2}{\varphi_{\text{nr}}}}$$ \hspace{1cm} (6)

The asymmetric distribution of the $T_2$ relaxation time can be described by $S_{\text{kp}}$, and the variation range of $S_{\text{kp}}$ is [-1,1]. A positive value suggests that the sample is dominated by a short $T_2$ relaxation time, while a negative value implies a high proportion of long $T_2$ relaxation time (Equation (7)).

$$S_{\text{kp}} = \frac{\varphi_{94} + \varphi_{16} - 2\varphi_{50}}{2(\varphi_{84} - \varphi_{16})} + \frac{\varphi_{84} - 2\varphi_{50}}{2(\varphi_{95} - \varphi_{5})}$$ \hspace{1cm} (7)

3.3.3. Pore Components Derived from NMR $T_2$ Spectra

The pore components ($S_1$, $S_2$, and $S_3$) can also be obtained by NMR $T_2$ spectral analysis, representing various pore volumes corresponding to micropores, mesopores, and macropores, respectively [42]. The pore components are critical for evaluating micropore structures. The larger the $S_2$ and $S_3$, the better the micropore structure would be. $S_1$, $S_2$, and $S_3$ can be calculated by Equation (8).
\[ S_1 = \sum_{i=1}^{n_1} T_{2i} \phi_i \]  
\[ S_2 = \sum_{i=n_1}^{n_2} T_{2i} \phi_i \]  
\[ S_3 = \sum_{i=n_2}^{N} T_{2i} \phi_i \]  

where \( n_1 \) and \( n_2 \) are the category boundaries of pore components.

NMR-derived pore components have strong regional differences and need to be calibrated by MICP data. As shown in Figure A3, the pore types of the Es4 sandstone reservoirs can be classified into micropores, mesopores, and macropores by using the category boundaries of 0.1 \( \mu m \) and 1.0 \( \mu m \). The category boundaries were selected based on pore throat size distribution of the Es4 reservoirs and regional empirical values proposed by Wu et al. (2019) [39]. The corresponding category boundaries of \( S_1-S_2 \) and \( S_2-S_3 \) are approximately 27.4 ms and 289.9 ms, respectively (Figure A3).

4. Results
4.1. Petrophysical Properties and Pore Types

The porosity and permeability results of 753 sandstone core samples from the Es4 sandstone reservoirs indicate that the petrophysical properties are generally unfavorable with porosity mainly ranging from 3.0% to 24% (average 12.3%) and permeability ranging from 0.005 to 191.68 mD (averaging 10.75 mD) (Figure 3). The majority of the samples belong to the category of low-permeability sandstones (Figure 3). When excluded samples with micro-fractures, the porosity and permeability show a good correlation \( (R^2 = 0.70) \) because the presence of micro-fractures can significantly improve the reservoir permeability but has little influence on the porosity. The samples with micro-fractures are generally characterized by high permeability values but highly variable porosities (5–25%) (Figure 3B).

As can be seen from SEM images and casting thin sections, the pore systems are mainly constituted by residual intergranular pores, dissolution pores, micropores, and a minor amount of micro-fractures (Figure 4). The residual intergranular pores are irregular in shapes (Figure 4A,B,H,I,J), which are often associated with carbonate cement (Figure 4A,B). The primary intergranular pores visible under petrographic microscope are generally characterized by larger pore diameter as compared to secondary dissolution pores.
The dissolution pores are predominantly in feldspars, lithic fragments, and carbonate cements (Figure 4A,B,H,I,J). Some of the intergranular pores and dissolution pores are filled by clay minerals, forming intercrystalline pores (Figure 4E,F). There are a large number of intercrystalline pores within kaolinite, chlorite, and mixed layer illite/smectite, and the pore diameter is less than 1 μm (Figure 4E,F). The micropores formed by authigenic clay minerals and dissolution clastic particles contribute to high porosity but have low permeability [53,54].

Figure 4. Microscopic characteristics of pore systems in the Es4 sandstone reservoirs. (A,B) Intergranular pores and dissolution pores; (C,D) Micro-fractures; (E,F) Intercrystalline pores; (G) Dissolution pores; (H,I) Intergranular pores and dissolution pores; (J) Residual intergranular pores and dissolution pores; (K,L) Extensive carbonate cementation.

4.2. Pore Throat Size Distribution from MICP Measurements

The MICP results show that the capillary pressure curves of the sandstone samples are different in morphology (Figure 5A), suggesting complex pore structures and microscopic connectivity. The longer the flat segment of the capillary curves, the better the sorting and microscopic connectivity. The capillary pressure curves of samples Cn371-1 and F153-1 exhibit a longer flat segment during the mercury intrusion (Figure 5A), indicating a high proportion of large and connected pore throats and good microscopic connectivity. As shown in Figure 5B, the pore throat radius of samples Cn371-1 and F153-1 are concentrated between 0.5 and 5.0 μm. In contrast, the flat segments of sample F119-1 and Sample G351-1 are short (Figure 5A), suggesting poor sorting and microscopic connectivity of pore throats.
Figure 5. Pore structure characteristics of the Es4 sandstone reservoirs obtained from MICP data. Capillary pressure cures (A) and pore throat characteristics (B) for four typical samples.

Highly variable pore throat radii are quite apparent from the MICP data with the average pore throat radius being mostly less than 2.0 μm with a non-uniform distribution (Figure 6B). Most of the mercury withdrawal efficiency is in the range of 25–45% (Figure 6A). The maximum mercury saturation has a concentrated distribution from 65% to 95%, with an average value of 89.69% (Figure 6C). Other parameters that can reflect pore structure characteristics, such as porosity (φ), permeability (k), and displacement pressure (Pd) also have a wide range of distribution (Figures 3 and 6D). Overall, the pore structures in the Es4 sandstone reservoirs are characterized by strong reservoir heterogeneities, highly variable pore throat sizes, and poor microscopic connectivity.

Figure 6. Distribution of mercury withdrawal efficiency (A), average pore throat radius (B), maximum mercury saturation (C), and displacement pressure (D) for 23 sandstone samples.

4.3. Micro-Fracture Analysis

Micro-fractures are well developed in Es4 reservoirs, which can be observed on core photos, photomicrographs, and MICP analysis (Figure 7). The capillary curves of samples with micro-fractures exhibit an obvious two-segment pattern in the mercury intrusion stage (Figure 7). In the initial stage of mercury intrusion, the mercury saturation increases
rapidly, and the capillary pressure curve shows a relatively long flat segment, which is characteristic of fracture systems. With the increasing mercury pressure, mercury saturation increases slowly, and the capillary curve becomes inclined (Figure 7). However, the response of micro-fractures on the NMR $T_2$ spectra is not obvious, implying that the micro-fractures have little effect on the detection of pores. Macroscopically, the development of fractures also has a minor effect on porosity but a significant effect on the permeability (Figure 3B).

| Sample No. | Characteristics of Micro-Fractures |
|------------|-----------------------------------|
| G890-1     | ![Image](image1)                    |
|            | ![Image](image2)                    |

Figure 7. Characteristics of micro-fractures of cores, photomicrographs, MICP, and NMR plots (samples Cn371-2 and G890-1).
The pore structures in the samples investigated are generally characterized by a low displacement pressure (Pd), a large average pore throat radius, and a poor pore throat sorting (Figure 7). The presence of micro-fractures can greatly alter the pore structure and make an excessive contribution to the fluid low in sandstones (Figure 7) [55].

4.4. NMR Experiments and Data Analysis

4.4.1. NMR T2: Spectral Analysis

The pore size distribution is closely related to the characteristics of the NMR T2 spectra. For example, the T2 relaxation times with longer values are usually associated with larger pores [48,56]. Hence, NMR T2 spectra can provide crucial information for pore size evaluation. Different from the pore throat size distribution derived from MICP analysis, NMR experiments can provide information of the full-range pore structures [9]. According to the NMR experiments performed on 21 sandstone samples from the E4 reservoir, the NMR T2 spectra are characterized as both unimodal and bimodal (Figure 8), indicating great differences among various sandstone samples [56]. Some typical NMR T2 spectral distributions are shown in Figure 8A–F.

Samples with unimodal distribution (e.g., samples C276-2 and L218-3) display a continuous pore size distribution, while the T2 relaxation time is mainly between 0.1 ms and 1000 ms (Figure 8A, B). The pore systems are dominated by dissolution pores and residual intergranular pores (Figure 4A, G,H). Samples with bimodal behaviors are shown to have both long and short T2 components (Figure 8C–F), implying a wide range of pore size distribution and strong reservoir heterogeneities. The bimodal behaviors can be further separated into bimodal large pore and bimodal small pore behaviors, considering the morphological features on the NMR T2 spectra. The bimodal large pore samples (e.g., samples C141-1 and F119-1) usually have a wider range of T2 values (mainly in the range of 0.1–3000 ms) compared with these samples with unimodal distributions (Figure 8C, D). The pore systems are dominated by residual intergranular pores and dissolution pores (Figure 4I, J). Very large T2 values (>100 ms) are rare in the sandstone samples with bimodal small pore distributions due to the lack of the large pores (Figure 4K, L). The bimodal small pore distributions are usually characterized by a higher left peak and a lower right peak. The T2 values of the left peak are commonly less than 10 ms, and the amplitude is significantly higher than that of the right peak (Figure 8E, F).

Figure 8. Typical NMR T2 spectral distributions (A, B) showing unimodal behaviors in samples C276-2 and L218-3; (C, D) showing bimodal large pores in samples C141-1 and F119-1; (E, F) showing bimodal small pores in samples G351-2 and G890-2.
4.4.2. Effective Movable Fluid in Pore Space

The pore fluid in sandstones can be separated into irreducible and movable fluid (including the effective movable fluid and immobile fluid) at the $T_{2	ext{water}}$ values [29,57,58]. The irreducible fluid is considered to be clay- or capillary-bound water retained in pores [47]. NMR analyses show that the $T_{2	ext{water}}$ values obtained from 20 sandstone samples have a wide range from 2.83–150.41 ms (averaging 42.29 ms), indicating the complexity of movable fluid distribution in the $E_4$ sandstone reservoirs (Table 1). Previous studies have shown that the centrifugal component cannot reach zero even when $T_2 > T_{2	ext{water}}$ (Figure 9) [40,41]. There may still be ineffective movable fluid (immobile fluid) presence in the pore throats beyond the $T_{2	ext{water}}$ values (Figure 9) due to the presence of isolated intergranular pores. The porosity for movable fluids ($\varphi_m$) is not effective in characterizing movable fluid distribution. As shown in Figure 9, the samples with similar $\varphi_m$ show different pore size distribution and petrophysical properties. Therefore, a new parameter (porosity for effective movable fluids ($\varphi_{em}$)) was proposed [40,41], which is the product of the saturation for effective movable fluid and NMR porosity under 100% water-saturated state (Figure 9).

![Figure 9. NMR $T_2$ spectra and effective movable fluid distribution obtained from sandstone samples in the $E_4$ reservoirs. (A) Sample C141-1, $\varphi = 17.5\%$, $K = 11.61$ mD; (B) Sample C406-1, $\varphi = 13.6\%$, $K = 0.76$ mD; (C) Sample F153-1, $\varphi = 10.9\%$, $K = 4.40$ mD.](image)

Statistical analysis shows that the $\varphi_{em}$ varies from 0.02% to 5.98% (averaging 2.41%) (Table 1), suggesting a poor connectivity of microspore throats and complex occurrence states of fluids in the micro-pore space. The value of $\varphi_{em}$ exhibits a strong correlation with average pore throat radius ($R_{ave}$) ($R^2 = 0.76$), implying that $\varphi_{em}$ is closely associated with micro-pore structures (Figure 10). The correlation between $\varphi_{em}$ and permeability was also investigated, and an excellent exponential correlation ($R^2 = 0.90$) was obtained (Figure 11A). However, $\varphi_{em}$ is less strongly correlated with porosity, with a relatively low determination coefficient ($R^2 = 0.47$; Figure 11B). The movable fluid mainly exists in the large intergranular pores connected by effective pore throats, since the micropores and small secondary dissolution pores are isolated or very poorly connected. Therefore, the permeability is mainly contributed by $\varphi_{em}$ rather than porosity. Consequently, $\varphi_{em}$ is more suitable to characterize the reservoir permeability capacity and microspore structures.
Figure 10. Relationship between porosity for effective movable fluids and average pore throat radius.

Figure 11. Relationships between porosity for effective movable fluids and petrophysical parameters. (A) Effective movable fluids versus permeability; (B) Effective movable fluids versus porosity.

Table 1. NMR $T_2$ spectral parameters of 21 sandstone samples obtained by 100% water-saturated and centrifugal $T_2$ spectra. Sample Cn371-1 is not well consolidated, falling apart during the centrifugation experiment; thus, there is no centrifugation data for the sample.

| Sample No. | Core Data | NMR Data |
|------------|-----------|-----------|
|            | $q$ (%)   | $K$ (md)  | $q_{pm}$ (%) | $T_{2max}$ (ms) | $T_{2mid}$ (ms) | $T_{2cutoff}$ (ms) | $T_{2ave}$ (ms) | $T_{2peak}$ (ms) | $q_{pm}-max$ (%) | $S_w$ (%) | $S_{kp}$ (%) |
| F119-1     | 12.30     | 0.77      | 1.68         | 1084.37 | 48.32 | 130.41 | 28.62 | 118.11 | 155.22 | 0.18 | 72.73 | 0.0013 |
| F119-2     | 8.05      | 0.05      | 0.02         | 135.10 | 0.99  | 3.95  | 1.00  | 2.69  | 1.20  | 0.17 | 97.52 | -0.0062 |
| F143-1     | 10.97     | 0.56      | 2.60         | 310.79 | 25.85 | 46.93 | 15.31 | 45.99 | 62.95 | 0.21 | 64.85 | -0.0080 |
| F151-1-1   | 8.00      | 0.09      | 0.11         | 270.50 | 3.07  | 12.82 | 3.00  | 6.66  | 3.65  | 0.23 | 93.44 | -0.0108 |
| F153-1     | 10.85     | 4.40      | 3.79         | 1431.46 | 52.02 | 91.99 | 24.18 | 126.32 | 144.81 | 0.22 | 60.94 | -0.0020 |
| G351-1     | 3.60      | 0.04      | 0.47         | 117.58 | 1.07  | 2.83  | 1.23  | 6.65  | 1.12  | 0.09 | 80.24 | 0.0014 |
| G351-2     | 10.74     | 0.04      | 0.29         | 126.04 | 2.54  | 8.96  | 2.56  | 4.79  | 2.97  | 0.28 | 90.48 | -0.0108 |
| G890-1     | 17.25     | 54.30     | 5.20         | 541.59 | 61.30 | 84.02 | 39.96 | 87.91 | 102.34 | 0.47 | 60.71 | -0.0970 |
| G890-2     | 2.72      | 0.04      | 0.23         | 144.81 | 1.38  | 5.09  | 1.51  | 11.96 | 1.59  | 0.08 | 86.94 | 0.0010 |
| C141-1     | 17.5      | 11.61     | 4.30         | 2327.20 | 31.50 | 41.49 | 21.63 | 142.49 | 155.22 | 0.16 | 52.55 | 0.0020 |
| C141-2     | 9.06      | 0.61      | 3.01         | 666.99 | 2.08  | 4.72  | 2.27  | 6.66  | 1.38  | 0.21 | 68.48 | -0.0018 |
| C276-1     | 10.42     | 0.40      | 2.36         | 821.43 | 12.67 | 34.36 | 14.40 | 50.94 | 9.01  | 0.17 | 68.53 | -0.0009 |
| C276-2     | 13.60     | 1.26      | 2.97         | 880.49 | 12.56 | 43.45 | 13.08 | 40.60 | 6.37  | 0.25 | 74.79 | -0.0056 |
| C406-1     | 13.61     | 0.76      | 2.49         | 580.52 | 4.83  | 7.97  | 6.56  | 44.95 | 3.65  | 0.32 | 63.53 | 0.0280 |
| Cn371-1    | 20.44     | 17.13     | /            | 943.79 | 11.23 | /     | 9.07  | 23.24 | 18.04 | 0.42 | /     | -0.0548 |
| L218-1     | 16.65     | 10.01     | 5.98         | 505.26 | 71.80 | 85.61 | 48.74 | 99.95 | 117.58 | 0.44 | 56.01 | -0.0785 |
| L218-2     | 14.47     | 6.12      | 5.15         | 505.26 | 47.11 | 64.88 | 33.00 | 79.25 | 102.34 | 0.33 | 58.41 | -0.0322 |
| L218-3     | 14.11     | 2.37      | 4.32         | 505.26 | 50.60 | 76.98 | 31.63 | 81.90 | 102.34 | 0.32 | 61.78 | -0.0353 |
| L752-1     | 10.43     | 0.15      | 0.87         | 289.94 | 7.49  | 63.97 | 7.57  | 30.43 | 54.79 | 0.14 | 83.63 | 0.0003 |
| L752-2     | 9.07      | 0.19      | 2.35         | 541.73 | 2.25  | 5.53  | 2.95  | 14.34 | 1.70  | 0.18 | 68.44 | 0.0025 |
| L752-3     | 7.57      | 0.05      | 0.08         | 191.16 | 1.91  | 9.88  | 1.98  | 4.37  | 2.10  | 0.22 | 96.57 | -0.0046 |
5. Discussions

5.1. Relationships between NMR T2 Spectral Parameters and Petrophysical Properties

Petrophysical properties are controlled by the microscopic pore structures of reservoirs [59–61]. Based on 21 sandstone samples from the E4 reservoir in the Dongying Depression, the relationships between the NMR T2 spectral parameters and petrophysical parameters were investigated (Figure 12). The NMR T2 spectral parameters are shown to be intimately correlated to reservoir petrophysical properties, indicating that the T2 spectral parameters can be used to characterize reservoir permeability and microscopic pore structures.

Pore volumes from helium porosity measurement can also be adequately approximated by NMR experiments [28,29]. The NMR porosity exhibits a strong correlation with helium porosity ($R^2 = 0.87$; Figure 12A), suggesting the effectiveness of using the surface relaxation mechanism in reflecting pore systems of low-permeability reservoirs. In addition, a strong exponential correlation between $T_{2gm}$ and permeability is observed for the E4 reservoirs ($R^2 = 0.71$; Figure 12B), implying that the sandstones with abundant long T2 components are characteristic of good reservoir quality. In contrast, the sandstone with poor reservoir quality is mainly associated with short T2 components, correlating with a lower value of $T_{2gm}$. The value of $T_{2mid}$ appears to be well correlated with permeability ($R^2 = 0.70$; Figure 12C), indicating that high-quality reservoirs are dominated by large $T_{2mid}$ values. $S_h$ is consistent with the proportions of macropores and shows a strong correlation with permeability ($R^2 = 0.80$; Figure 12D), suggesting that macropores are of great importance for improving reservoir permeability. To further illustrate this point, the correlation between $S_{kp}$ and permeability was investigated. As shown in Figure 12E, $S_{kp}$ has a negative correlation with permeability ($R^2 = 0.61$), indicating that $S_{kp}$ decreases with increasing permeability. This is because reservoirs with low $S_{kp}$ often have high proportions of macropores, and these macropores have profound controls on the overall permeability of the reservoir. Therefore, macropore systems greatly control the pore structures and reservoir quality of low-permeability sandstones. The $T_{2cutoff}$ value is weakly correlated with permeability with a determination coefficient ($R^2$) of 0.53 (Figure 12F). This indicates that the pore radius corresponding to the bound fluids are complex, reflecting the complexity of microscopic pore structures.
Figure 12. Relationships between NMR $T_2$ spectral parameters and petrophysical properties. (A) NMR porosity versus helium porosity; (B) $T_{2gm}$ versus permeability; (C) $T_{2mid}$ versus permeability; (D) $S_3$ versus permeability; (E) $S_{kp}$ versus permeability; (F) $T_{2cutoff}$ versus permeability.

5.2. Comparison of NMR $T_2$ Spectral Parameters and MICP Capillary Parameters

In order to verify the reliability of NMR $T_2$ spectral parameters for pore structure characterization, a comparative analysis between $T_2$ spectral parameters and MICP capillary parameters was carried out for parameters with similar petrophysical proxies.

MICP measurement is only effective in measuring pore throat sizes, whereas NMR analysis can better detect the pore sizes. Limited by the maximum mercury injection pressure attainable, some nanopore throats cannot be detected by MICP measurements, but the majority of micro/nano-scale pore throats can be obtained. In addition, influenced by a Haines jump, the mercury cannot enter into tortuous pore networks uniformly, rather in a process of rapid filling [62,63]. The effect of Haines jump is more significant in the initial stage of mercury intrusion, when most pores are unfilled [63]. This results in that a considerable amount of the large throats has not been accounted for. Therefore, the throat size distribution derived from MICP data is apparently narrower compared with the actual distribution (Figures 13 and 14). As shown in Figure 13, the large pore throats do exist in sandstone samples, and they can be detected by 2D image analysis based on the “maximal balls” algorithm [64].
However, the overall trends in pore sizes revealed by optical photomicrograph analysis, MICP, and NMR are the same (Figures 14 and 15A,B). Regression analysis shows that the $T_2$ relaxation times ($T_{2\text{max}}$ and $T_{2\text{mid}}$) are consistent with the corresponding pore throat radius derived from MICP data. In general, $T_{2\text{max}}$ and $T_{2\text{mid}}$ increase with increasing pore throat radius (maximum pore throat radius ($R_{\text{max}}$) and median pore throat radius ($R_{\text{50}}$)), with good exponential correlations (Figure 15A,B), confirming the applicability of using NMR $T_2$ relaxation times to calculate pore sizes. Due to the shielding effect of large throats caused by Haines jump, the correlation between the $T_{2\text{max}}$ and maximum pore throat radius ($R_{\text{max}}$) is relatively weak ($R^2 = 0.67$; Figure 15A).

We also investigated the reliability of using NMR $T_2$ spectral parameters to approximate the pore size distribution by using the sorting coefficient ($\sigma$) and skewness ($S_{kp}$). As shown in Figure 15C, there is a weak to moderate determination correlation ($R^2 = 0.53$) between $\sigma$ calculated from NMR and MICP data, but there is no apparent correlation between $S_{kp}$ derived from NMR and MICP data (Figure 15D). This may be because MICP is
effective in identifying smaller pore throats but is not suitable to detect large pore throats [65], whereas NMR can provide the full-range pore structure information [30]. Thus, the pore size distribution derived from NMR experiments is wider than that from MICP measurements (Figure A3). This leads to some differences in the morphological characteristics and skewness derived from NMR and MICP.

![Figure 15](image-url)

**Figure 15.** Comparative analysis of NMR $T_2$ spectral parameters and MICP capillary parameters. (A) $T_{\text{max}}$ versus $R_{\text{max}}$; (B) $T_{\text{mid}}$ versus $R_{\text{50}}$; (C) $\sigma_{\text{NMR}}$ versus $\sigma_{\text{MICP}}$; (D) NMR $S_0$ versus MICP $S_0$; (E) $\phi_{\text{em}}$ versus displacement pressure; (F) $S_{\text{mov}}$ in NMR experiment and maximum mercury saturation from MICP measurements.

As shown in Figure 15E, $\phi_{\text{em}}$ derived from NMR experiments is consistent with the displacement pressure computed from MICP measurements, showing a negative relationship ($R^2 = 0.78$). In addition, for the Es sandstone reservoirs, the movable fluid saturation ($S_{\text{mov}}$) obtained from NMR appears to be correlated with the maximum mercury saturation from MICP ($R^2 = 0.59$; Figure 15F). The results indicate that the NMR $T_2$ spectral parameters are effective in estimating the fluid distribution in pore space and microscopic pore connectivity.

The comparative results demonstrate that the NMR $T_2$ spectral parameters are in good fits with the capillary parameters, suggesting that the pore structures can be evaluated and characterized by NMR analysis. In addition, the NMR $T_2$ spectral parameters can be used to characterize the capillary parameters that can usually not be easily obtained by MICP. If continuous NMR logging data is available, continuous pore structures can be obtained by using the NMR $T_2$ spectral parameters [28].
5.3. Application of NMR T2 Spectral Analysis in Pore Structure Evaluation

NMR T2 spectral analysis can provide quantitative parameters for reservoir classification and evaluation. According to the NMR T2 spectral parameters combined with petrography, MICP, and NMR T2: spectral analysis, four typical pore structures (I, II, III, and IV) of the sandstone reservoir in the Dongying Depression are classified (Figure 16). The results show that the T2 spectral parameters are sensitive to the characteristics of pore structures (Figure 17 and Table 2). From Type I to Type IV pore structures, the values of $T2_{max}, T2_{avg}, T2_{min}$, and $q_{wm}$ gradually increase, while the value of irreducible water saturation ($S_w$) decreases (Figure 17 and Table 2). The detailed information of pore structures are as follows.

The capillary pressure curves of the Type I pore structure exhibit a long flat segment in the mercury intrusion stage, and it has the lowest displacement pressure (Figure 16I-A). The NMR T2 spectra are characterized as unimodal with longer relaxation time, implying a high proportion of large pores (Figure 16I-B). The T2 relaxation time ranges between 1 and 300 ms with a concentrated distribution (Figure 16I-B), and the corresponding pore size ranges from 0.6 to 4.0 μm. This is usually typical of micro-fractures or large pore systems. The large pore systems are the combination of residual intergranular pores and dissolution pores (Figure 16I-C). Since the Type I pore structure has a larger pore throat radius and a better microscopic connectivity, it exhibits comparatively higher permeability.

The capillary pressure curves show a relatively low displacement pressure and maximum mercury saturation in the Type II pore structure (Figure 16II-A). The NMR T2 spectra exhibit unimodal or bimodal behaviors with a higher right peak (Figure 16II-B). The T2 relaxation time is mainly between 1 and 200 ms (Figure 16II-B), with pore sizes being concentrated mostly between 0.1 and 1.6 μm. The volume of the pore throat is lower than that in the Type I pore structure. The pore types of the Type II pore structure are composed mainly of intergranular pores and dissolution pores (Figure 16II-C), which show a good petrophysical properties and microscopic connectivity.

Type III capillary pressure curves are characterized by a shorter flat segment and a higher displacement pressure (Figure 16III-A). The NMR T2 spectra are typical of bimodal. The T2 relaxation time has a wide range of distribution, and the proportion of large pore throats is low (Figure 16III-B). The pore types of the Type III pore structure are dominated by isolated dissolution pores with rare residual intergranular pores. Extensively, carbonate cementation is present in the Type III pore structure-dominated sandstones, forming a pore system dominated by small pore throats (Figure 16III-C).

The flat segments of Type IV capillary pressure curves are the shortest compared with all the other types of pore structures, and the microscopic connectivity is the poorest (Figure 16IV-A). The NMR T2 spectra are characterized as unimodal or weak-bimodal with shorter relaxation time, indicating the presence of a high proportion of small pores (Figure 16IV-B). The T2 relaxation time is mainly between 0.3 and 10 ms (Figure 16IV-B), and the corresponding pore sizes are in the range of 0.004–0.1 μm. Except for a small amount of isolated dissolution pores, micropores dominate the pore space of the Type IV pore structure. The Type IV pore structure-dominated sandstones are characterized by strong compaction and extensive carbonate cementation with no visible pores in thin sections (Figure 16IV-C). In some cases, abundant clay-dominated micropores are present in Type IV pore structure-dominated sandstones, exhibiting high porosity but low permeability.
Figure 16. Classification and evaluation of various types of pore structures in the Es4 sandstone reservoirs, showing the microscopic pore types and pore throat characteristics for different types of pore structures.

Figure 17. NMR $T_2$ spectral parameters of four types of pore structures: (A) $\phi_{em}$ versus $S_{wi}$; (B) $T_{2mid}$ versus $T_{2max}$; (C) $T_{2gm}$ versus $T_{2ave}$; (D) $\phi_i^{-max}$ versus $S$. 
Table 2. Statistics of the NMR $T_2$ spectral parameters for four types of pore structures in the E4 sandstone reservoirs.

| Type | $T_{2\text{avg}}$ (ms) | $T_{2\text{max}}$ (ms) | $T_{2\text{ave}}$ (ms) | $T_{2\text{min}}$ (ms) | $\phi_{\text{emax}}$ (%) | $S_i$ | $S_{\text{mi}}$ (%) | $q_{\text{em}}$ (%) |
|------|-------------------------|------------------------|-----------------------|------------------------|--------------------------|------|-------------------|------------------|
| I    | 11.23–71.80/505.26–1362.77/203.24–142.49/9.07–48.84/10.16–0.47/483.80–1547.59/52.55–60.71/4.3–5.98/5.16 | 43.96/1079.46/88.40/29.85/0.37/1229.92/56.42 | 12.56–52.02/505.26–1362.77/126.32–138.08–33.02–0.22–0.33/510.09–1482.50/58.41–74.79/2.97–5.15/4.06 | 40.59/830.62/82.02/25.47/0.28/950.21/63.89 | 2.08–81.32/1084.37/6.66–118.11/2.27–26.82/0.14–0.32/16.29–572.47/30/63.5–83.63/0.87–3.01/2.19 | 0.99–3.07/1.8 117.58–270.50/2.69–11.96/1.0–3.0/1.80.08–0.28/0.02–0.47/0.02 | 3 | 164.20 | 19 | 8 | 0.18 | 80.24–97.52/90.87 |

6. Conclusions

The petrophysical properties, pore structures, and effective movable fluid in pore space were analyzed by integrated optical and SEM petrographic and petrophysical analyses including poroperm, MICP, and NMR measurements. Various quantitative $T_2$ spectral parameters derived from NMR experiments were employed to characterize and evaluate the pore structures of the Eocene sandstone reservoirs in the Dongying Depression, Bohai Bay Basin, China. Some key findings are as follows:

1. Petrographic analysis reveals that the pore systems in the Eocene sandstone are composed mainly of residual intergranular pores, dissolution pores, micropores, and a minor amount of micro-fractures.

2. The $T_{2\phi m}$, $T_{2\text{mid}}$, $S_i$, and $\phi_{\text{em}}$ parameters have positive relationships with permeability, suggesting that the proportion of large and effective pores has a profound control on the overall permeability of the sandstones. Thus, the permeability of the Eocene sandstone is mainly dominated by large pore systems.

3. The NMR $T_2$ spectral parameters exhibit excellent correlations with MICP capillary parameters, indicating that the NMR $T_2$ spectral parameters also contain rich information on pore structures and movable fluids. Thus, pore structures, pore fluid distribution, and reservoir permeability can be effectively evaluated by using NMR $T_2$ spectral parameters.

4. A comprehensive classification scheme of the Eocene sandstones is established based on NMR $T_2$ spectral parameters while considering the petrophysical properties and macroscopic behaviors. The E4 sandstone reservoirs are classified into four types of pore structures (I, II, III, and IV). Type I and II pore structures exhibit good petrophysical properties and microscopic connectivity. Our study demonstrates the effectiveness and applicability of the NMR technique in characterizing low-permeability sandstone reservoirs and provides a basis for further improving reservoir quality evaluation in the Bohai Bay Basin, China. However, limited by the quantity of NMR experimental data, continuous evaluation of pore structure throughout entire reservoir intervals would not be feasible. The combination of NMR experimental data and NMR logging or conventional logging data would be crucial for further extending these research findings.

Author Contributions: Conceptualization, Y.L. and K.L.; methodology, Y.L., K.L. and Y.W.; validation, Y.L. and Y.W.; formal analysis, Y.L.; investigation, Y.L., K.L. and Y.W.; resources, Y.L. and Y.W.; data curation, Y.L.; writing—original draft preparation, Y.L.; writing—review and editing, Y.L., K.L. and Y.W.; visualization, Y.L.; supervision, K.L.; project administration, K.L.; funding acquisition, K.L. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by the National Natural Science Foundation of China (Grant No. 41821002), the Strategic Priority Research Program of the Chinese Academy of Sciences (No. XDA14010401) and the National Science & Technology Major Project of China (No. 2017ZX05009001).

Institutional Review Board Statement: Not applicable.
Informed Consent Statement: Not applicable.

Data Availability Statement: The data presented in this study are available on request from the corresponding author.

Conflicts of Interest: The authors declare no conflict of interest.

Appendix A

| System | Epoch (Series)          | Age (Ma) | Stratigraphy | Thickness (m) | Lithology                                      | Sedimentary facies | Tectonic evolution |
|--------|-------------------------|----------|--------------|---------------|------------------------------------------------|--------------------|---------------------|
| Quaternary |                        |          | Pinyuan (Q₄) | 250–350       | Uncemented loess                                 |                    |                     |
|        |                        |          | Minghuazhen (N₄) | 100–120       | Sandstone and siltstone, interbedded transgressive mudstones | Flood plain         |                     |
|        |                        |          | Guantao (N₃) | 300–400       | Sandstone and conglomerate                        | Rafted fluvial      | Meandering (fluvial) |
|        |                        |          | E₄ (Upper)   | 500–700       | Sandstone and mudstone, some conglomerates       | Delta               |                     |
|        |                        |          | E₄ (Lower)   |              |                                                 |                    |                     |
| Neogene |                        |          | Daping (E₃) | 110–160       | Mudstone, siltstone and sandstone intercalated coarse sand, conglomerates and biogenic carbonates | Lacustrine          |                     |
|        |                        |          | E₃ (Upper)   | 120–230       |                                             | Delta               |                     |
|        |                        |          | E₃ (Middle)  | 700–1200      | Sandstone and shale, marl, shale and siltstone, some anhydrites and salt | Coastal shallow lacustrine | Deep lacustrine |
|        |                        |          | E₃ (Lower)   |              |                                                 | Semi-deep lacustrine | Shallow lacustrine |
| Oligocene |                        |          | Shahaiping (C₄) | 150–350      | Mudstone and siltstone, some anhydrites           | Beach-bar           |                     |
|        |                        |          | E₄ (Upper)   | 200–400       | Some anhydrites                                  | Turbidite fan       | Lacustrine          |
|        |                        |          | E₄ (Lower)   |              |                                                 |                    |                     |
| Paleogene |                        |          | Kongliang (R₃) | 50–150        | Shale and siltstone with some intercalated sandstone and local volcanics | Delta               |                     |
|        |                        |          | E₅ (Upper)   |              |                                                 |                    |                     |
|        |                        |          | E₅ (Lower)   |              |                                                 |                    |                     |
| Paleozoic |                        |          | Basement rocks | 200          | Crystalline basement (granitic)                 |                    |                     |

Figure A1. Schematic Tertiary stratigraphy and tectonic evolution in the Dongying Depression.
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