Effect of pore structure on oil-bearing property in the third member of Paleogene Funing Formation in Subei Basin, East China

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Abstract
Mercury injection capillary pressure (MICP) tests, nuclear magnetic resonance (NMR), (fluorescence) thin section, X-ray diffraction (XRD), and scanning electron microscope (SEM) analyses were used to describe the size and distribution of entire pore-throat structures in the sandstones of the E1f3 (the third member of Paleogene Funing Formation) in the Subei Basin. The lithologies of E1f3 in the Subei Basin are mainly dark-gray, very fine-grained sandstones and siltstones, interbedded with dark mudstones. The pore systems predominantly feature secondary intergranular and intragranular dissolution pores, micropores coexisting with minor amounts of intergranular pores, and microfractures. The high threshold pressure and bulk volume of irreducible fluids values and the significant variation in the NMR and MICP parameters indicate that the E1f3 reservoirs are characterized by complex and heterogeneous microscopic pore structures. Microscopic pore-throat parameters are linked with macroscopic properties through the reservoir quality index (RQI). The NMR T2 (transverse time relaxation) spectrum is unimodal or bimodal but with weak right peaks, indicating the rarity of large intergranular pores. However, large-scale pore throats, though only account for a minor part of the total pore volume, significantly contribute to the total permeability. The abundance of small-scale pore-throat systems (short T2 components) results in high irreducible water content. Therefore, the oil saturation in E1f3 sandstones is low, and the pore structure, especially the number of micropores, determines the oil-bearing property. Oil primarily occurs in the intragranular dissolution pores with minor amounts occurring in the large intergranular pores. Most of the micropores are bound by capillary water. The sandstones with chlorite clay minerals tend to be oil-wet and have high oil-bearing potential, while the abundance of detrital clay or illite contributes to a low oil-bearing grade. The combination of core and microscopic observations and the MICP and NMR analyses have allowed the determination of the pore structure characteristics and their coupling effects on oil-bearing property.
1 | INTRODUCTION

Pore structure significantly influences storage capabilities, transport properties, and oil-bearing property in rock reservoirs. Sandstones typically have a wide range of pore-throat sizes, spanning from the nanoscale (<1 μm) to the microscale; therefore, various techniques and theories must be applied to qualitatively and quantitatively describe the complex pore geometry and pore-throat structure in sandstones. Mercury injection capillary pressure (MICP) experiments are widely used to determine the complexity and heterogeneity of pore-throat distribution. Laboratory NMR measurements provide uncalibrated pore-size distributions and determine fluid mobility in reservoir rocks. Additionally, NMR measurements can be used to identify oil-bearing pore-size distribution. Therefore, a combination of core and microscopic observations, as well as MICP and NMR analyses, allows the determination of pore structure characteristics and their effect on oil-bearing property.

The Paleogene Funing Formation is now the primary hydrocarbon exploration target in the Subei Basin, East China. Many scholars have revealed the tectonic evolution, stratigraphy, sedimentology, and reservoir heterogeneity of this formation. However, the reservoirs in E1f3 have various pore structures due to the complex diagenesis the sandstones had experienced during their geological history. Additionally, the oil saturation in the Funing Formation reservoirs is relatively low and heterogeneous. Consequently, to determine the amount of oil in the microscopic pore structure is of great importance. Presently, few studies have been conducted on pore structures and their coupling effect on the microscopic oil-bearing property.

Therefore, the main goals of this study are (a) to describe the porosity, permeability, and pore-throat systems in the Funing Formation in Subei Basin; (b) to provide insights into the pore network characteristics using a combination of MICP, NMR, thin section, and scanning electron microscope (SEM) analyses; and (c) to determine the effects of pore structure on the microscopic oil-bearing property through thin section fluorescence and NMR measurements.

2 | GEOLOGICAL SETTINGS

The Subei Basin is located in the South Yellow Sea Basin and includes the Yanfu Depression, Jianhu Uplift, and Dongtai Depression (Figure 1), with several sags and low uplifts within each depression. The Subei Basin is the largest (total area: 3.5 × 10^4 km^2) Mesozoic-Cenozoic basin in southeastern China. Presently, more than 70 oil and gas fields have been discovered in the Dongtai Depression in the southern Subei Basin, and the source rocks are part of the Paleogene Funing and Cretaceous Taizhou Formations. The Subei Basin is a rift basin formed during the Late Cretaceous (Figure 1) that has experienced two main rift phases (83-54.9 and 54.9-38) Ma.

The Mesozoic-Cenozoic sedimentary sequence, which is over 7 km thick, consists of the Cretaceous Taizhou Formation (K2f); the Paleogene Funing (E1f), Dainan (E2d), and Sanduo Formations (E3s); the Neogene Yancheng Formation (N2y); and the Quaternary Dongtai (Qd) Formation. The study area is located in the southeastern part of the Dongtai Depression with a geothermal gradient of approximately 27 °C/km, and the primary period of hydrocarbon accumulation was between 47 and 41.5 Ma. The Funing Formation can be divided into four members (E1f1-E1f4), and the E1f3 (the third member of the Funing Formation) is composed of deltaic deposits and has a lithology of gray-dark mudstone interbedded with silt-fine sandstone, as determined by core observations.

3 | SAMPLES AND METHODS

3.1 | Methodology

The pore (throat) radius r can be linked to the capillary pressure when assuming cylindrical pores for the MICP tests:

\[ r = \frac{2\sigma \cos \theta}{P_c}, \]

where \( P_c \) is the capillary pressure (MPa), \( \sigma = 0.48 \) N/m, and \( \theta = 140^\circ \) for the conversion of mercury pressure to pore-throat size.

The NMR transverse relaxation times \( (T_2) \) include three relaxation mechanisms under a gradient magnetic field: surface relaxation \( (T_{2s}) \), bulk fluid relaxation \( (T_{2B}) \), and diffusion relaxation \( (T_{2D}) \) (Equation 2).

\[ \frac{1}{T_2} = \frac{1}{T_{2B}} + \frac{1}{T_{2D}} + \frac{1}{T_{2S}}. \]

In the laboratory NMR tests (water-saturated porous media), the diffusion and bulk relaxation times (order of seconds) are much longer than the surface relaxation (order of milliseconds). Therefore, surface relaxation \( (T_{2s}) \) is the smallest and can be neglected.
becomes the most critical mechanism affecting the NMR relaxation.\textsuperscript{23,28} The $T_2$ value can be linked to pore size (Equation 3).\textsuperscript{26}

$$\frac{1}{T_2} = \frac{1}{T_{2s}} = \frac{S}{V} = \frac{\rho}{V} = \frac{a}{r},$$

in which $\rho$ is the surface relaxivity ($\mu$m/ns) to convert the NMR $T_2$ to the pore-size distribution, $S$ ($\mu$m$^2$) and $V$ ($\mu$m$^3$) are the pore surface area and pore volume, respectively, and $a$ is the pore shape constant.\textsuperscript{23,26,27,29,30}

Nuclear magnetic resonance (NMR) porosity, bulk volume irreducible of fluids (BVI), free fluid index (FFI), $T_{2gm}$ ($T_2$-weighted mean on a logarithmic scale), and $T_{2cutoff}$ (transition $T_2$ value separating BVI from FFI) can be determined via NMR measurements.\textsuperscript{3,31,32} Additionally, NMR analysis provides an estimate of permeability on the porosity distribution spectrum using a combination of empirical and theoretical relationships.\textsuperscript{30,33}

### 3.2 Experimental measurements

Core plug samples 1 inch (2.5 cm) in diameter and 2.0 inches (5 cm) in length, collected from the three key wells, were subjected to laboratory investigations, including (a) mineralogy analysis using X-ray diffraction (XRD), (b) composition and pore system analysis through optical thin section observations, (c) clay mineral and micropore detection using a SEM, (d) porosity and permeability measurements using the CMS-300 instrument, (e) MICP tests, and (f) NMR measurements.
X-ray diffraction analysis was conducted on the whole-rock (bulk) and clay fraction (<2 μm) to identify the clay mineral species and rock composition content (semi-quantitative) according to Chinese Industry Standard SY/T5163-2010.

The grain size and composition, as well as the pore systems, were detected by thin section using a Leica optical microscope. The thin sections of 30 μm in thickness were impregnated with a blue epifluorescent dye (stained with Alizarin Red S and potassium ferricyanide) and were point-counted to determine the types and amounts of detrital grains, pores, and authigenic cements. The thin sections prepared for the fluorescence observation of hydrocarbons in the pores were not impregnated with epoxy, and the thin section fluorescence was analyzed by

**FIGURE 2** Core photograph showing the lithology of Paleogene Funing Formation in Subei Basin

**FIGURE 3** Cross-plot of permeability vs porosity of oil shale in Funing Formation in Subei Basin

\[ y = 0.0076e^{1.363x} \]

\[ R^2 = 0.4438 \]
FIGURE 4 Thin sections and scanning electron microscope (SEM) images showing the mineralogy and composition of oil shale in Funing Formation in Subei Basin. A. Intergranular pores coexisting with intragranular pores, J20, 2752.21 m. B. Intragranular dissolution pores, J20, 2753.3 m. C. Intragranular (feldspar) dissolution pores, J20, 2753.54 m. D. Intragranular (feldspar) dissolution pores, J20, 2754.18 m. E. Feldspar dissolution pores, J23, SEM. F. Micropores within clay minerals (kaolinite and mixed-layer illite/smectite), J23, SEM. G. Webby illite, Ji 20, 2755.91 m. H. Chlorite containing micropores, Ji 20, 2754.85 m. I. Microfracture, J20, 2752.21 m. J. Carbonate cements (Fe-dolomites) filling the intergranular pores and intragranular dissolution pores, J20, 2753.54 m.

ultraviolet light using a ZEISS microscope fitted with a mercury lamp.

Scanning electron microscope analysis, using a microscope equipped with a backscattered electron (BSE) detector, was conducted on the freshly broken rock surfaces (carbon-coated) to identify the various types of clay minerals and the associated intercrystal pores, as well as the feldspar dissolution pores.
Helium porosity and gas permeability were measured using the CMS-300 instrument at a net confining pressure of 800 psi, according to the Chinese Industry Standard SY/T 5336–2006.

Mercury injection capillary pressure (MICP) tests were conducted on the core plugs following the SY/T 5346-2005 Chinese standard. The 9505 instrument was used at a temperature of 25°C and atmospheric pressure, and the mercury intrusion/extrusion curves were obtained for pressures ranging from 0.02 to 101 MPa.

The core samples were analyzed by NMR measurements to obtain the $T_2$ spectrum in the saturated state (100% brine saturated) and centrifugal state (mobile water was removed by a centrifugal machine), which reflect the entire pore-size distribution. The Niumag instrument was used for the core plug samples, which was set at a 2 MHZ frequency for the primary magnetic field, waiting time of 3000 ms, signal superposition times of 64, and echo spacing of 0.116 ms, following the Chinese Industry Standard (SY/T6490-2007). Larger pores correspond to longer $T_2$ times, while smaller pores correspond to shorter $T_2$ times.34

Nuclear magnetic resonance measurements were also performed on the sealed core plugs. The core plugs were firstly saturated with brine and then evaluated to obtain the $T_2$ spectrum. Then, the samples were kept in the MnCl₂ brine with a salinity of 15 000 mg/L to remove the water (only oil remained), and the NMR measurements were performed again to obtain the $T_2$ distribution of the residual oil.8,35

### TABLE 1  Mineralogy determined by X-ray diffraction

| Sample  | Quartz | K-feldspar | Plagioclase | Calcite | Dolomite and Fe-dolomite | Pyrite | Siderite | Total clay | Illite | Kaolinite | Chlorite | Illite/smectite mixed layers |
|---------|--------|------------|-------------|---------|--------------------------|--------|----------|------------|-------|------------|---------|-----------------------------|
| 2767    | 20     | 5          | 10          | 10      | 3                        | 1      | 0        | 51         | 17    | 3          | 3       | 77                          |
| 2823    | 19     | 5          | 8           | 6       | 1                        | 1      | 0        | 60         | 16    | 7          | 8       | 69                          |
| 2890    | 50     | 5          | 14          | 8       | 1                        | 1      | 1        | 20         | 20    | 9          | 9       | 62                          |
| 2906    | 30     | 7          | 18          | 7       | 1                        | 1      | 0        | 35         | 16    | 11         | 11      | 62                          |
| 2996    | 20     | 5          | 7           | 15      | 1                        | 2      | 0        | 49         | 24    | 5          | 4       | 67                          |
| 2752.21 | 41     | 8          | 28          | 1       | 1                        | 1      | 0        | 20         | 5     | 14         | 24      | 57                          |
| 2753.54 | 44     | 10         | 26          | 8       | 1                        | 0      | 0        | 11         | 6     | 26         | 23      | 45                          |
| 2758.12 | 42     | 13         | 27          | 1       | 1                        | 2      | 0        | 14         | 8     | 16         | 24      | 52                          |
| 2759.6  | 37     | 12         | 38          | 1       | 0                        | 1      | 0        | 11         | 8     | 15         | 18      | 59                          |
| 3010.15 | 20     | 0          | 17          | 6       | 0                        | 2      | 0        | 55         | 21    | 3          | 3       | 73                          |
| 3010.64 | 14     | 0          | 10          | 9       | 0                        | 2      | 0        | 65         | 21    | 2          | 2       | 75                          |
| 2755.91 | 37     | 9          | 24          | 0       | 1                        | 0      | 0        | 29         | 12    | 12         | 9       | 67                          |
| 3012.2  | 19     | 4          | 6           | 16      | 1                        | 2      | 0        | 52         | 29    | 4          | 4       | 63                          |
| 3013.5  | 18     | 3          | 5           | 13      | 0                        | 1      | 0        | 60         | 29    | 5          | 5       | 61                          |
| 3014.92 | 12     | 1          | 2           | 7       | 0                        | 2      | 0        | 59         | 17    | 20         | 5       | 69                          |

### RESULTS

#### 4.1 Porosity, permeability, and pore systems

The lithologies of member 3 of the Paleogene Funing Formation (E1f₃) in the Subei Basin are dominantly dark-gray, very fine-grained sandstones and siltstones (Figure 2A, B), interbedded with massive dark mudstones (Figure 2C). Cross-beddings (tabular, wavy), parallel beddings, and mud intraclasts can be observed in the siltstone successions (Figure 2A–D). An oil-stained core is commonly observed (Figure 2E), and there are many transitional lithologies, including silty mudstones and shaly siltstones (Figure 2F).

The porosity and permeability measurements, based on 88 core plug samples, show that the permeability ranged from 0.004 to 29.03 mD with an average of 4.8 mD, and the porosity fluctuated between 5.46% and 22.97%, with an average of 16.0% (Figure 3). Few samples were characterized by high porosity and low permeability (<1 mD). The correlation between the permeability and porosity (correlation coefficient: $R^2 = .44$) indicates a complex pore structure (Figure 3). Samples with the same porosity may have very different permeability values, and pore network characteristics modified by diagenesis are crucial factors in determining permeability (Torabi et al. 2013).
Pore types within the E1* reservoirs in the Subei Basin include a mix of minor amounts of intergranular pores, large amounts of secondary intergranular and intragranular pores, and abundant micropores (Figure 4). The intragranular dissolution pores, which occur within the feldspar grains, are commonly observed (Figure 4A–D) and coexisting with a minor amount of intergranular pores (Figure 4A). The optical microscope revealed the coexistence of large amounts of secondary pores and minor amounts of intergranular pores. The SEM analysis confirmed the abundance of intragranular dissolution pores due to feldspar dissolution (Figure 4E). Besides the intragranular dissolution pores, the micropores (<10 μm), which were below the resolution limits of the optical microscope, could be detected with the SEM observations within the authigenic clay minerals (kaolinite, mixed-layer illite and smectite, and chlorites) (Figure 4F, G).

Another type of pore space is microfractures (aperture < 0.1 mm), which cannot be seen with the naked eye, but can be detected by thin section analysis (Figure 4I). However, the thin section and SEM observations revealed...
that the pore spaces were occupied by cementing materials, mostly in the form of carbonate cements (Figure 4J). The XRD analysis and thin section identification confirmed the presence of the carbonate cements (calcites and dolomite) and authigenic clay minerals (chlorite, kaolinite, and mixed-layer illite/smectite), which play a significant role in reducing the reservoir quality and narrowing the pore-throat size in sandstones (Table 1).

4.2 | Pore network characteristics

4.2.1 | MICP pore-throat distribution

The surface tension of mercury and the contact angle ($\sigma = 0.48 \text{ N/m}$ and $\theta = 140^\circ$) (Equation 1) are known, and therefore, the capillary pressure curves are good representations of the pore-throat distribution. The two capillary curves and the corresponding pore-throat distribution, as well as the permeability contributions, are presented in Figure 5. Qualitatively, Figure 5 indicates that the heterogeneity of the sample in Figure 5A differed from that in the sample in Figure 5C according to the curvatures and the capillary parameters. The sample in Figure 5A displayed the lowest threshold pressure (0.68 MPa) (largest maximum pore-throat sizes $r_{\text{max}}$) and the highest $S_{\text{Hg max}}$ (maximum mercury saturation during the MICP analysis). From the corresponding Figure 5B, the pore-throat distribution was unimodal, and the relatively small number of larger pore throats significantly contributes to the sample's permeability (Figure 5B) (Table 2). The sample presented in Figure 5A exhibited the best reservoir pore structure. Conversely, the sample presented in Figure 5C was characteristic of the poorest pore structure, which is supported by the highest threshold pressure (6.88 MPa) and the lowest $r_{\text{max}}$ values (Table 2). Additionally, the pore-throat distribution and permeability contribution curves revealed that the pore throats were much smaller; however, the relatively
larger pore throats primarily contribute to the permeability (Figure 5D).

4.2.2 Nuclear magnetic resonance

Nuclear magnetic resonance $T_2$ distributions provide vital information on pore structure. The pore-size distributions of the sandstones in E1f were either unimodal or bimodal. In the NMR $T_2$ spectrum, the short components ($T_2s$) ($<1$ ms) were mainly associated with the micropores, while the long $T_2$ components ($>10$ ms) indicated the large intergranular pores and microfractures, which were mobile. The transitional $T_2$ components ($1$ ms $< T_2 < 10$ ms) were primarily related to the substantial amounts of intragranular pores (Figure 6). The main $T_2$ peaks that occurred within the $T_2$ component ranging over 10 ms indicated the abundance of intragranular pores, which agrees with the thin section and SEM analysis (Figure 4). The significantly weak right peaks imply that large intergranular pores and microfractures were rare (Figure 6).

A fixed $T_2$ value directly correlates with the pore size, and the $T_2$ spectrum is essentially the pore-size distribution. Therefore, other than the NMR porosity, many petrophysical parameters, such as BVI, FFI, $T_{2\text{cutoff}}$, and $T_{2\text{gm}}$, could be directly or indirectly derived from the NMR measurements (Table 3). Additionally, the parameters FFI and $T_{2\text{gm}}$ are commonly used for the estimation of permeability. The $T_{2\text{cutoff}}$, which separates the capillary and clay-bound water (BVI) residing in the small pores (short $T_2$ components) from the mobile water (FFI) residing in the large pores (long $T_2$ components) (Figure 6), could be determined from the method given by Gao and Li, based on the NMR measurements at saturated and irreducible conditions. Additionally, the volumes of irreducible (BVI) and mobile (FFI) fluids could be estimated based on the $T_{2\text{cutoff}}$ value. For instance, the $T_{2\text{cutoff}}$ was 2.31 ms, which is much lower than the standard value of sandstones (33 ms), and the related BVI value had been determined as 87.01% (Figure 6).

The MICP and NMR results, combined with the thin section and SEM analyses, demonstrate that the sandstones are characterized by complex and heterogeneous microscopic pore structures (Figures 4-6).

5 DISCUSSION

5.1 Effect of pore structure on oiliness

The reservoir quality index (RQI) is defined as the square root of the ratio of permeability to fractional porosity: $RQI = \sqrt{K/\Phi}$ ($K$ is in $\mu$m² and $\Phi$ is percentage) (Amaefule et al. 1993). The RQI becomes a critical parameter linking the microscopic pore structure with the macroscopic performances.

Presented in Figure 7 are the cross-plots of RQI vs MICP parameters (average pore-throat size) and NMR parameters (Table 3). The reservoir quality index (RQI) values link mercury injection capillary pressure (MICP) average pore-throat size (A) and nuclear magnetic resonance (NMR) bulk volume irreducible of fluids (BVI) values (B) in Funing Formation in Subei Basin.
(BVI). The high coefficients of determination ($R^2$) imply the capability of RQI of linking the NMR and MICP parameters (Figure 7), with both parameters describing the pore-throat systems from different aspects. The higher the RQI values, the larger the pore-throat size, and lower amounts of immobile water will be encountered (Figure 7). Therefore, the more inferior the reservoir pore structure, the lower the RQI values will be.

The core-measured irreducible water content ($S_{wi}$) also showed a negative correlation with the RQI (Figure 8), indicating that more inferior pore structures will result in higher irreducible water content. Actually, an inferior pore structure is always associated with a high content of micropores, indicating low fluid mobility because most of the micropores are not connected by effective pore throats. The MICP analysis also revealed that though there were abundant micropores in the samples, the permeability was determined by the small amounts of large pore throats (Figure 5). Furthermore, the oil saturation ($S_o$) for the sealed cores revealed a positive relationship with RQI (Figure 9), indicating that the oil saturation increases with the pore structure, that

**Figure 8**  Plot of core-measured $S_{wi}$ vs reservoir quality index (RQI) values in Funing Formation in Subei Basin

**Figure 9**  Plot of core-measured $S_o$ vs reservoir quality index (RQI) values in Funing Formation in Subei Basin

**Figure 10**  Plot of core-measured oil saturation ($S_o$) vs $S_{wi}$ (irreducible water content) in Funing Formation in Subei Basin

**Figure 11**  Nuclear magnetic resonance (NMR) $T_2$ spectrum for oil-bearing layer, oil–water-bearing layer, low porosity oil-bearing layer and dry layer
is, a good pore structure implies a high oil-bearing property. This relationship is valid for many sandstones, especially the tight sandstones with poor reservoir qualities and complex pore structures. Additionally, the $S_{wi}$ show a negative relationship with the oil saturation measured for the sealed cores, indicating that a high amount of irreducible water will result in a low oil saturation (Figure 10).

From Figure 8 to Figure 10, it can be concluded that the irreducible water content in the E$_1$f$_3$ sandstones was high, and reached as much as 95% (ranging from 30% to 97.79% with an average of 55.7%), indicating low oil saturation. In fact, the oil saturation was low in the E$_1$f$_3$ reservoir; therefore, it was vital to determine the microscopic occurrence of oil in the microscopic pore systems.

### 5.2 Microscopic oil-bearing property

The NMR analysis confirmed that the significant pore-size distribution in the E$_1$f$_3$ sandstones occurred around 1.0-10.0 ms (Figure 6). The rareness of right peaks implies that there were minor amounts of large intergranular pores in the E$_1$f$_3$ sandstones. Additionally, the high BVI values indicate that most of the pore systems were immobile, and the fluids would be residual in the small-scale (capillary or clay-bound) pores (Figure 6) (Table 3). However, reservoir quality is mostly dependent on small amounts of large-scale pores, and the MICP analysis also confirmed that the small amounts of larger pore throats significantly contribute to permeability (Figure 5).

The NMR $T_2$ spectra at the 100% saturated status were either unimodal or bimodal (mostly bimodal), but some samples displayed only weak right peaks, implying the co-existence of large-scale and small-scale pores (separation by $T_2$ cutoff) (Figures 6 and 11). Therefore, the $T_2$ spectra of water signals were reflected throughout the entire pore-size distribution. However, the $T_2$ spectra of oil signals (the water signals were removed, and oil was residual from the MnCl$_2$ brine) can reflect the microscopic oil-bearing property or the oil occurrence within the various pore sizes. Figure 11 shows the water and oil signals for the typical oil-bearing layers (Figure 11A), oil–water-bearing layer (Figure 11B), low porosity oil-bearing layer (Figure 11C), and dry layer (no mobile fluids) (Figure 11D).
For the typical oil-bearing layer, the $T_2$ spectrum of water signals, which reflects the entire pore-size distribution, was bimodal and right-skewed, indicating the abundance of large-scale pores ($T_2 > T_{2\text{cutoff}}$) (Figure 11A). The $T_2$ spectrum of oil signals (bimodal and right-skewed) revealed that most of the oils were residual within the large-scale pores, and minor amounts of oil were present in the small-scale pores. Therefore, in the typical oil-bearing layer, the large-scale pore systems play an essential role in the microscopic oil-bearing property (Figure 11A). The thin section fluorescence confirmed that the large-scale pore-throat systems were oil-bearing because most of the edges of the intergranular pores were fluorescent (Figure 12A), indicating that the large-scale pore systems were oil-saturated, agreeing well with the NMR $T_2$ spectrum of oil signals (Figures 11A and 12A).

The typical oil–water-bearing layer (both oil and water would be produced in an oil test or production) had relatively low amplitudes of right peaks, and, therefore, smaller amounts of large-scale pore systems (Figure 11B). The $T_2$ spectrum of water signals was also bimodal, and most of the right $T_2$ peaks were oil-saturated according to the $T_2$ spectrum of oil signals. Additionally, the left peaks, which are primarily associated with the intragranular pores of smaller pore size, were also oil-saturated, which could be demonstrated by the moderate amplitudes of the left peaks of the $T_2$ spectrum of oil signals (Figure 11B). The thin section fluorescence revealed that most of the intragranular pores

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**FIGURE 13** Well log expressions and microscopic oil-bearing property of typical water layers, dry layers, and oil-bearing layers. Layers 1, 2, 4, 5, 7 are dry layers, and layer 3 is water layer, while layer 6 is oil-bearing layer.
were fluorescent; for instance, the intragranular dissolution pore spaces in Figure 12B and C emitted strong blue-green fluorescence.

The typical low porosity oil-bearing layer (only a small amount of oil would be produced in an oil test or production) was characterized by bimodal $T_2$ behaviors, but with a
significantly weak right $T_2$ peak (Figure 11C). The dominant pore spaces were intragranular pores with small pore sizes, and there were no visible large intergranular pores present, resulting in poor reservoir quality and a high BVI value. Therefore, the low porosity oil-bearing layer was different from the typical oil-bearing layer due to its relatively poor reservoir quality (Figure 11C). From the NMR $T_2$ spectrum of oil signals, it could be concluded that most of the oil was present in the small-scale pore systems, and only some of the large-scale pores were oil-saturated (Figure 11C). Actually, the thin section fluorescence produced intragranular pore spaces that emitted blue-green fluorescence (Figure 12C, 12). However, the oil-bearing grades were not very high due to the rareness of large intragranular pores.

The typical dry layer (no fluid is produced during an oil test or production) displayed mostly unimodal $T_2$ and bimodal behavior (very weak right peak) (Figure 11D). The BVI values were substantially high, and most of the fluids were residual in the small-scale pore systems (capillary or clay-bound micropores). There were no evident oil signals in the $T_2$ spectrum, indicating that oil had not accumulated in the capillary or clay-bound micropores (Figure 11D). It is not strange that oil may not prefer to be accumulated in the micropores, and the thin section fluorescence confirmed that there was no visible fluorescence in the samples that were characterized by abundant micropores (Figure 12E, F).

The typical dry layers (Layers 1, 2, 4, 5, 7) characteristically display low porosity (high bulk density but low CNL porosity) and medium to high resistivity (Figure 13). The dry layers were associated with the siltstones with low porosity (<10%) but very high irreducible water content (>75%) (Figure 13). No evident oil signals were detected in the dry layers (Layer 5), and the $T_2$ distributions were primarily unimodal or bimodal but with very weak right peaks (Figure 13). The water-bearing layer (Layer 3) was recognized as high porosity (low bulk density, high AC values) but low to medium resistivity (Figure 13). The oil layer (Layer 6) was characterized by medium to high resistivity, and there was an evident deviation between the deep and shallow resistivity logs (Layer 3), with the lithology of very fine-grained sandstones. The core-measured porosity was as high as 17.49% for Layer 6 (a low porosity oil layer), and the permeability was 3.14 mD. The NMR analysis indicated that the oil-bearing layer had a bimodal $T_2$ behavior with low amplitudes, and the oil-bearing pore sizes widely ranged from 1 to 100 ms (Figure 13).

It is difficult for oil to permeate into the small-scale pores of water-wet sandstone due to strong capillary resistance. However, the presence of chlorites may change the rocks from water-wet to oil-wet, and oil accumulates in pores with a moderate amount of scattered flaky chlorite. The clay mineral assemblages of the high-grade oil-bearing cores (oil-stained or oil trace) were mostly kaolinite and chlorite, and the pore systems primarily included feldspar dissolution pores, clay mineral micropores, and minor amounts of intergranular pores (Figure 14A–C). Conversely, the clay mineral assemblages of low oil-bearing cores (fluorescence or no fluorescence) were predominantly illite, illite-smectite mixed layers, or detrital clays, and the pore systems also included feldspar dissolution pores (Figure 14D–F).

Previous studies have confirmed that oil prefers to accumulate in the residual pore spaces around carbonate cements. However, both the high and low-grade oil-bearing cores displayed abundant carbonate cements (Figure 14G,H), and carbonate cements (calcite, dolomite, and Fe-dolomite) are persistent in the E1f3 sandstones (Figure 14LJ).

6 | CONCLUSIONS

The lithologies of member 3 of the Paleogene Funing Formation (E1f3) in the Subei Basin are predominantly dark-gray siltstones interbedded with dark mudstones. The pore types include a coexistence of minor amounts of intergranular pores, large amounts of secondary intergranular and intragranular pores, and micropores, as well as microfractures.

The sandstones are characterized by complex and heterogeneous microscopic pore structures. The high threshold pressure, high values of BVI, and a considerable variation in the NMR and MICP parameters indicate a complex pore-throat system spanning wide ranges. The RQI helps to link the MICP pore-throat distribution with the NMR pore-size distribution and reflects the microscopic pore structure and macroscopic reservoir quality. Additionally, the oil saturations are low but reveal a positive relationship with RQI.

Oil and water signals for the typical oil layer, oil–water layer, low porosity oil layer, and dry layers were investigated, and oil is primarily present in the intragranular dissolution pores, with minor amounts within the large intergranular pores. Most of the micropores were not oil-saturated because they were mostly bound by capillary water. The samples abundant in chlorite clay minerals were prone to be oil-wet and have high oil-bearing potential, while the abundance in detrital clay or illite contributed to a low oil-bearing potential.

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